December 6, 2023

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

RE: In the Matter of an Exploration of Comparative Performance Metrics and Improvements to Natural Gas Service Quality Reports
Docket No. G002, G022, G004, G011, G008/CI-22-548

Dear Mr. Seuffert:

The Department of Commerce ("the Department" or "DOC"), CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas ("CenterPoint Energy" or "CPE"), Commission staff, Great Plains Natural Gas Co. ("Great Plains"), Greater Minnesota Gas, Inc. ("GMG"), Minnesota Energy Resources Corporation ("MERC"), the Minnesota Office of Pipeline Safety ("MNOPS"), and Northern States Power Company d/b/a Xcel Energy ("Xcel"), collectively the Natural Gas Working Group (NGWG), respectfully submit this report to the Minnesota Public Utilities Commission ("Commission") in response to the Commission's Orders in the Gas Utilities' individual service quality annual reports for reporting year 2020.[1] This filing is submitted with respect to the Commission's ordering point establishing a working group for the continued exploration of comparative gas service quality metrics.

The NGWG met five times between April 2023 and October 2023 to discuss gas utility service quality reporting.[2] Specifically, the NGWG explored the possibility of benchmarking utility service quality by examining Delaware's Natural Gas Service Reliability and System Planning Standards; discussed whether current service quality reporting requirements could be modified to produce more uniform reporting and facilitate accurate cross-utility comparisons; reviewed each gas service quality reporting requirement to identify where, or if, currently reported information is not being utilized when evaluating a utility's quality of service; explored the possibility of producing public-facing summaries similar to what is required of electric utilities; and resolved remaining questions surrounding utilities proposed web-based metrics.

With this filing, the NGWG reports back to the Commission on its discussions regarding gas service quality reporting. The NGWG recommends several changes to gas service quality reporting and was able to confirm that there are no existing or ready-made service quality comparisons that could be used to

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[1] Docket Nos. Docket Nos. G-002/M-21-301, G-008/M-21-303, G-022/M-21-304, G-004/M-21-300, and G-011/M-21-313

[2] At the time of this filing, Docket Nos. G-002/M-23-77, G-008/M-23-79, G-011/M-23-80, G-004/M-23-78, and G-022/M-23-81 contain the most recent gas service quality reports for Xcel, CenterPoint Energy, MERC, Great Plains, and GMG, respectively.

benchmark a utility's service quality against other similarly sized utilities across the nation. A summary of the NGWG's recommendations is included at the end of the report.

Background

Commission Order on Gas Utilities' 2019 and 2018 Service Quality Reports

On July 21, 2021, the Commission Ordered each of the Gas Utilities[3] to supplement their 2020 service quality reports with a discussion of appropriate methods to compare performance nationally or regionally. This discussion was to identify existing industry service quality comparisons, what service qualities could be best for comparison, appropriate similar utilities to compare against, and how such a national comparison could be integrated in the future of service quality reporting.[4] In discussing the purpose of this ordering point at the July 15, 2021 agenda meeting, Commissioners elaborated on how they hope to use the requested information:

- tell a positive story about the Minnesota regulatory model;
- display the good work being done by Minnesota Natural Gas Companies;
- create more uniform reporting using common language while also recognizing that each utility is different, and thus may have different goals for each metric; and
- use benchmarking and comparison in a manner similar to what is being done with Minnesota's electric utilities currently.

Gas Utilities' 2021 Supplemental Discussion on Comparative Metrics

In response to the July 21, 2021, Commission Order, the Gas Utilities jointly filed a supplemental discussion in which the utilities described their search for regional/national comparative metrics on natural gas service quality and provided details on their findings. In their attempt to find comparative metrics, the Gas Utilities contacted numerous professional and trade organizations, examined their own reporting across a variety of regulatory bodies in their various jurisdictions (including those provided by peer utilities in each Gas Utility's holding company structure), reviewed filings and orders of other state utility commissions, and inquired of other gas utilities around the country using a professional trade organization polling tool. Additionally, the Gas Utilities reviewed the benchmarking effort occurring with Minnesota's electric utilities[5] and investigated data provided by the American Gas Association (AGA).[6]

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[3] Xcel Energy, CenterPoint Energy, Minnesota Energy Resources Co., Great Plains Natural Gas, and Greater Minnesota Gas.

[4] July 21, 2021 Commission Order, Docket Nos. G-002/M-20-460, G-008/20-453, G-022/20-459, G-004/M-20-452, and G-011/M-20-456

[5] During the July 15, 2021, agenda meeting, the Commission referred to the benchmarking done by electric utilities while outlining its request for the supplemental discussion on natural gas benchmarking.

[6] During the July 15, 2021, agenda meeting, the Department of Commerce queried if the AGA provides benchmarking information that could be used similarly to how the benchmarking information provided by the Institute of Electrical and Electronic Engineers (IEEE) is used for Electric service quality reports.

The Gas Utilities determined that there are not any existing or ready-made service quality comparisons that could be used for the Commission's intended purpose. Most of the available information regarding natural gas metrics relates to quantitative data about system reliability and safety which, while incorporated into the Gas Utilities' annual service quality reporting, is not the primary component of it. Additionally, this quantitative information was found to not have been compiled for benchmarking or comparative purposes.[7] The Natural Gas Utilities concluded that the heterogeneity among gas utilities has prevented the development of comparative metrics, whereas the more universally homogeneous electric distribution industry has been able to develop a mature body of comparative benchmarking information.

Because the Gas Utilities could not identify any universally reported service quality metrics beyond those regarding safety and reliability, the Gas Utilities were unable to suggest service quality metrics that would be suitable for comparison nor are they aware of a means for each utility to identify similar utilities to compare against.[8]

Commission Order on Gas Utilities' 2020 Service Quality Reports

With a stated goal to create meaningful, transparent, and public facing service quality reports, and an order to continue exploring comparative performance metrics, the Commission delegated authority to the Executive Secretary through an August 5, 2022 Order to implement a working group with the Gas Utilities, the Department, MNOPS, and Commission staff.

Discussion

Continued Exploration into Comparative Metrics (Benchmarking)

The NGWG reviewed each of the current gas service quality reporting requirements to, among other things, identify avenues by which cross-utility comparisons could be made. While discussing utilities' service interruption reporting requirements, the NGWG became aware of Delaware's Natural Gas Service Reliability and System Planning Standards.[9] Effective October 11, 2020, Delaware's Standards established gas distribution planning reporting requirements and gas reliability standards that apply to all gas distribution companies in the state.

Delaware utilizes an Annual Outage Rate ("AOR") and an Average Outage Duration ("AOD") to benchmark gas utility reliability. In addition to benchmarking utility reliability performance, Delaware's

[7] The Gas Utilities reported that, in some cases, there were representations of data on a state-by-state basis; however, there was not discrete information that each gas utility could use to identify its own comparative performance.

[8] In their search, the Gas Utilities found results of a survey from J.D. Power which asked customers how satisfied they were with their local gas utilities. While the survey provided results for large and medium sized utilities, small gas utilities, such as GMG and Great Plains, were not included.

[9] See Attachment 2

reliability and system planning standards require utilities to, on an annual basis, model their distribution system's safety and reliability and provide 5-year Infrastructure, Safety, and Reliability plans ("ISR"s).

At the fourth NGWG meeting, Rod Walker & Associates Consultancy, Inc. ("RWA") presented on the creation of Delaware's Natural Gas Service Reliability and System Planning Standards. As the consultants hired by the Delaware Public Service Commission ("DPSC") to aid in the creation of the Standards, RWA had extensive knowledge of the events that drove the creation of the standards and the approach used in the development of the standards. During their presentation, RWA explained that, while working with DPSC to create the Natural Gas Service Reliability and System Planning Standards, they had conducted a search similar to the one carried out by Minnesota's natural gas utilities with the hope of finding a national database of gas utility reliability benchmarking data metrics. However, like Minnesota's gas utilities, RWA was unable to find such data source and concluded that one does not currently exist.

Importantly, after the NGWG spoke with RWA, the Commission released a Notice of Comment on the content of Natural Gas Integrated Resource Plans ("IRPs") in Docket No. G008, G002, G011/CI-23-117 which asked whether future Gas IRPs should include infrastructure and/or distribution system planning. Modifications to utility service reliability reporting requirements may result from the discussions in Docket Nos. G008, G002, G011/CI-23-117. Because the extent to which utility distribution system planning will be incorporated into gas IRPs is unknown, the NGWG does not recommend any modifications to gas utility service reliability reporting requirements at this time.

Uniform Reporting and Docket Clean-up

Below, the NGWG outlines its recommended modifications to the gas service quality reporting requirements. Across several NGWG workgroup meetings, the NGWG reviewed each reporting requirement and discussed the reporting requirement's origin; how the information is being used when evaluating a utility's quality of service; if the currently collected information is achieving its intended purpose; and whether a reporting requirement could be modified to better facilitate cross utility comparisons, utilize industry standard metrics or information that is already being reported to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and/or to provide additional clarity on the information being requested and the expectations for how it should be presented within a service quality report.

The NGWG had difficulty in identifying service quality metrics that could be used to make accurate cross-utility comparisons. Differences in utility size and system material composition, geographic area, and business models make it difficult to accurately compare gas utilities' service quality performance. For instance, the number of leaks reported by a utility each year is influenced by a multitude of variables such as the frequency of leak surveys, the section of the distribution system being surveyed in a given year, and the leak survey technology being used. The impact these variables have on the number of leaks reported by a utility each year makes cross-utility comparisons less accurate than they would otherwise be.

The NGWG notes that Commission staff communicated with the Commission's Consumer Affairs Office (CAO) on all recommended modifications to ensure that CAO did not object to the NGWG's recommendations. For all reporting requirements not discussed below, the NGWG recommends continuing the status quo.

PHMSA Annual Reports

The NGWG found value in the Gas Utilities' Annual PHMSA Gas Distribution Reports. These reports include a description of the utility's distribution system, the total number of leaks reported on mains and services, excavation damages by cause, the number of EFVs and manual service line shut-off valves installed during the year, and the total number services with EFVs or manual service line shut-off valves at the end of the year. Utilities are not currently required to append these PHMSA reports to their service quality reports, although some currently do so voluntarily. Because of the relevance of the information provided in the Annual PHMSA Gas Distribution Reports, the NGWG recommends that the Gas Utilities append these reports to their service quality reports on a go forward basis.

Recommendation:

Require the Gas Utilities to append their annual PHMSA Gas Distribution Reports to all future Gas Service Quality Reports.

Involuntary Service Disconnections

The NGWG recommends that the Gas Utilities report on involuntary service disconnections using the new Residential Customer Status Reporting Template. The Residential Customer Status Reporting Template is utilized by utilities to report Cold Weather Rule data, including involuntary disconnections, in Docket No. E,G-999/PR-YY-02. The Commission's previous reporting requirements had utilities "reference" the disconnection information submitted under Minn. Stat. §§ 216B.091 and 216B.096 without any additional guidance on how this information should be reported. Because of this, utilities provide disconnection data in a variety of formats. Some use the old reporting template and provide annual disconnection data, others provide only monthly disconnection data, and some use the new Residential Customer Status Reports.

The new Residential Customer Status Report's table headings clearly indicate what information is being requested, which resolves reporting ambiguities present in the previous reporting template.[10] Additionally, the NGWG believes it would be beneficial for utilities to provide a narrative regarding their involuntary disconnection performance as needed, including any steps taken by the utility to improve its performance in the future.

Recommendation:

Require the Gas Utilities to provide data on Involuntary Service Disconnections by appending their December Residential Customer Status Reports, including data for January through December as filed in Docket No. E,G-999/PR-YY-02, in their annual service quality reports. Utilities shall also provide a narrative explanation of their involuntary service disconnection performance, as needed, including steps taken to improve performance in the future.

Previous Language:

[10] See April 14, 2023 Staff briefing papers at page 25, and April 20, 2023 ex parte communication in Docket No. G022/M-22-193.

In lieu of reporting data on involuntary service disconnections as contained in Minn. Rules, part 7826.1500, each utility shall reference the data that it submits under Minn. Stat. §§ 216B.091 and 216B.096.[11]

Customer Deposits

The NGWG recommends requiring utilities to update the Commission on their customer deposit practices when changes are made to customer deposit policies. The NGWG recognizes that customer deposits, if required at all, are only collected in a select set of circumstances. For that reason, few customer deposits are collected and/or held by a utility each year. Additionally, Commission staff confirmed with CAO that complaints regarding customer deposits are handled individually, and the annual information being provided in Gas Utilities' annual service quality reporting is not referenced when responding to such complaints. The revised reporting requirement for customer deposits would allow the Commission to stay informed on utility's customer deposit policies without hearing from utilities regarding their customer deposits on an annual basis.

Recommendation:

In place of any prior Customer Deposit reporting requirements, require that Utilities report on Customer Deposits within their annual service quality reports any time their deposit collection policies change. These reports shall include a description of the previous deposit collection policy, a description of the new deposit collection policy, the reason for the policy change, and data from the previous three years regarding the number of customers who were required to make a deposit as a condition of receiving service and the total number of deposits held at the end of each year.

Previous Language:

Each utility shall report the customer deposit data contained in Minn. Rules, part 7826.1900.[12]

And

Require the utilities to explain, beginning with their 2011 annual reports, the types of deposits (such as new deposits from new and reconnecting customers and the total number of deposits currently held) included in the reported number of "required customer deposits."[13]

Excavation Damages

The NGWG found that the number of damages based on data included in annual PHMSA reporting requirements provides a means to standardize reporting on gas line damages across utilities and can provide a comparative measure. However, the NGWG notes that the number of excavation damages

[11] August 26, 2010 Order, Docket No. G999/CI-09-409

[12] Id.

[13] March 6th, 2012 Order, Docket Nos. G002/M-11-360, G-001/M-11-361, G-004/M-11-363, G-007,011/M-10-374, G-008/M-10-378, and G-022/M-11-356

alone is not necessarily a reflection of service quality. For that reason, the NGWG's recommendation also includes a requirement for utilities to report the number of at-fault excavation damages and the number of excavation damages per 1,000 excavation tickets. The NGWG would still advise caution before drawing conclusions about one utility's service quality performance by comparing it to another utility's performance.

The NGWG believes the reporting of excavation damages should replace the current gas line damage and mislocate reporting requirements. Most, if not all, of a utility's gas line damages are from excavations, and at-fault excavation damages encompass mislocates. Utilities' PHMSA Annual Distribution Reports, which will be appended to all service quality reports going forward, include information on the number of times a utility mismarked or failed to mark a gas line in response to a locate request should the Commission or the Department desire that additional information.

Recommendation:

In place of the mislocate and system damage reporting requirements set by the Commission's August 26, 2010 Order in Docket No. G999/CI-09-409, require the Gas Utilities to report on excavation damages within their Annual Service Quality Reports using the following metrics:

a. *The number of excavation tickets received;*
b. *The number of excavation damages;*
c. *The number of excavation damages per 1,000 excavation tickets; and*
d. *The number of at fault damages.*

An "at fault damage" shall be defined as a damage where the root cause of the damage falls under the responsibility of the utility or its contractors including mislocates made by the company or its contract locating companies.

Previous Language:

Each utility shall report data on the number of gas lines damaged. The damage shall be categorized according to whether it was caused by the utility's employees or contractors, or whether it was due to any other unplanned cause.[14]

And

Each utility shall report data on mislocates, including the number of times a line is damaged due to a mismarked line or failure to mark a line. IPL and Xcel may include both gas and electric utility data in their reports.[15]

[14] August 26, 2010 Order, Docket No. G999/CI-09-409

[15] Id.

Customer Service Operation and Maintenance Expenses

The NGWG recommends removing the requirement for utilities to report on customer service O&M expenses annually as a part of utilities service quality reports. Since its inclusion in service quality reports, the O&M expense data has generated little discussion within each utility's service quality dockets. The Gas Utilities anticipate customer service O&M expenses will continue to be reviewed in general rate case proceedings.

Recommendation:

Going forward, the Gas Utilities shall no longer be required to provide information on customer service operation and maintenance expenses in their annual service quality reports pursuant to Order Point 2.O. of the Commission's August 26, 2010 Order in Docket No. G-999/CI-09-409.

Previous Language:

Each utility shall report customer-service related operations and maintenance expenses. The reports shall include only Minnesota-regulated, customer-service expenses and shall be based on the costs each utility records in its FERC accounts 901 and 903, plus payroll taxes and benefits.[16]

Excess Flow Valve ("EFV") and Manual Shut-off Valve Reporting

Utilities have two reporting requirements for EFVs and manual shut-off valves, both stemming from the Commission's investigation into Natural Gas Utilities' practices, tariffs, and assignment of costs for the installation of EFVs and other gas safety equipment in Docket No. G-999/CI-18-41.[17] Through this Docket, the Gas Utilities were required by the Commission to report the status of EFV and manual shut-off valve installations by customer class throughout the utilities' service territories; report a plan and timeline for completing the installation of EFVs and manual shut-off valves for the remainder of the utilities' service territories; and hold face-to-face meetings with the decision-makers of K-12 public districts and non-public schools with buildings in the utilities' service territory, public and private universities and colleges, hospitals, and multi-unit residential and nursing facilities.[18]

Over time, reporting on EFVs has moved from Docket No. G-999/CI-18-41 to Gas Utilities' Annual Service Quality Reports. Beginning with their 2017 annual service quality reports, the Gas Utilities were instructed to discuss how to provide ongoing monitoring and metrics toward the deployment of EFVs

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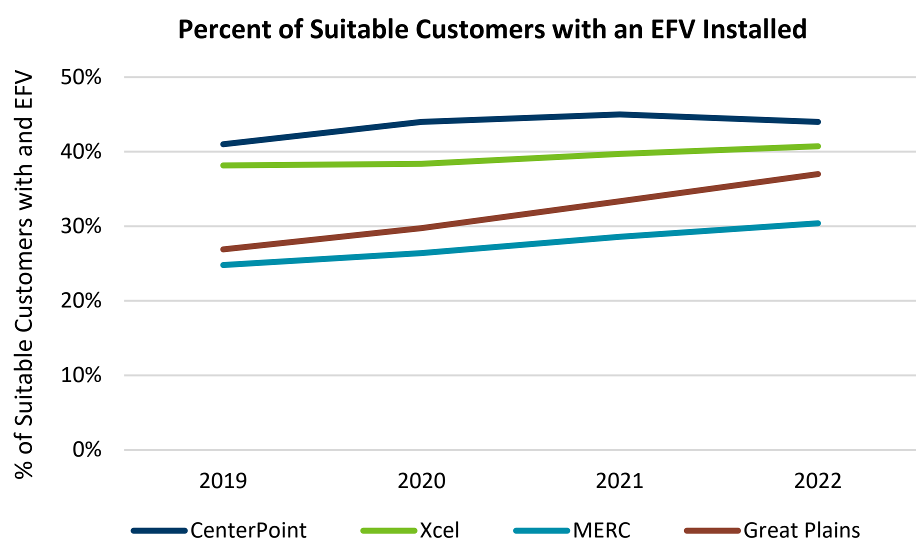
[16] Id.

[17] In October 2016, PHMSA amended 49 C.F.R § 192.383 to require that natural gas utilities install an EFV on an existing service line if a customer requests one, and left it up to the "operator's rate-setter" to determine how the costs of installation should be allocated (the "2016 Rule"). PHMSA also required natural gas utilities to notify customers of their right to request an EFV, including specific requirements for the notice. Docket No. G-999/CI-18-41 was opened for the purpose of gathering the information necessary for the Commission to carry out its role under the 2016 Rule.

[18] See August 20, 2018 Order in Docket No. G-999/CI-18-41.

and manual shut-off valves pursuant to the Commission's August 20, 2018 Order in Docket No. G-999/CI-18-41,[19] and propose uniform reporting requirements for reporting annual and total EFV and manual shut-off valves installations on utilities' distribution system for inclusion in future service quality reports.[20,21] Additionally, the Commission's February 23, 2021 Order in Docket No. No. G-999/CI-18-41 moved all future utility reports detailing progress of holding face-to-face meetings with the decision-makers of specified customers to Utilities' annual gas service quality dockets. Such reporting was set to continue through the 2025 reporting period.[22]

The NGWG found that several utilities have completed their EFV-related outreach pursuant to the Commission's Orders but continue to re-report the details of their outreach because EFV outreach reporting was set to continue through 2025. The Gas Utilities install EFVs and manual shut-off valves as new eligible service lines are installed, existing service lines are repaired or replaced, or if a customer requests installation. This means that, absent any additional intervention, the percent of customers eligible for an EFV who have an EFV installed will slowly continue to rise over time.



The NGWG recommends the Commission allow utilities that have completed the EFV outreach required by the Commission's July 13, 2019 Order in Docket No. 18-41 to cease reporting on EFVs, manual shut-off valves, and related outreach in their annual service quality reports. The information utilities provide on their EFV outreach efforts is being recycled as utilities complete their outreach requirements.

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[19] See April 12, 2018 Order in Docket Nos. G-004/M-18-286, G-008/M-18-312, G-022/M-18-314, G-002/M-18-316, and G-011/M-18-317.

[20] See November 14, 2019 Order in Docket Nos. G-004/M-19-280, G-004/M-19-300, G-011/M-19-303, and G-002/M-19-305.

[21] GMG was not required to participate in the development of uniform EFV reporting requirements because there are few GMG customers eligible for EFV installation that do not already have an EFV installed.

[22] See February 23, 2021 Order in Docket No. G-999/CI-18-41.

Additionally, going forward the percent of eligible customers with an EFV or manual shut-off valve installed will rise over time naturally, and will not provide a meaningful measure of utility service quality performance. Information on the total number of EFVs and manual shut-off valves installed on a utility's gas distribution system, and the number of EFVs and manual shut-off valves installed each year will continue to be included in gas service quality reports as a part of Gas Utilities' Annual PHMSA Gas Distribution Reports.

Recommendation:

Allow the Gas Utilities to confirm with the Commission that they have completed their EFV and manual shut-off valve outreach pursuant to the Commission's July 31, 2019 Order in Docket No. 18-41. Upon receiving confirmation from the Commission, utilities that have competed their EFV and manual shut-off valve outreach may cease annual reporting on EFVs, manual shut-off valves and related outreach in their annual service quality reports, including the reporting of EFV and manual shut-off valve data pursuant to the Commission's November 14, 2019 Order in Docket Nos. G-004/M-19-280, G-004/M-19-300, G-011/M-19-303, and G-002/M-19-305.[23] Utilities shall continue appending their annual PHMSA reports to their service quality reports, which contains information on the number of EFVs and manual shut-off valves installed on their system.

MNOPS Violation Letter and Emergency Response Violation Reporting Requirements

In their service quality reports, the Gas Utilities are currently required to report provide the number of emergency violation citations and the number of violation letters received from MNOPS each year. As a NGWG member, MNOPS provided clarity on how violations and violation letters function, noting that violation letters may contain multiple violations, and that other MNOPS violations exist other than emergency response violations. The NGWG recommends that the Commission update its MNOPS violation reporting requirements to require utilities to instead provide a summary of any violations cited by MNOPS and a count of violations by citation code. The NGWG believes that its recommended reporting requirement will provide the Commission with a more wholistic view into the MNOPS violations the Gas Utilities receive in a given year and will clear up any confusion on the differences between a MNOPS violation and a MNOPS violation letter.

Recommendation:

In place of prior reporting requirements on MNOPS violations and violation letters, the Gas Utilities shall instead provide a summary of any violations cited by MNOPS along with a description of the violation and remediation in each circumstance, and a count of violations by citation code within their Annual Service Quality Reports.

[23] GMG previously reported, in multiple annual service quality reports, that it completed the EFV and manual shut-off valve outreach requirements and has not been including additional EFV-related information and those service quality reports were accepted by the Commission; hence GMG interprets that as having received the necessary Commission confirmation of completion.

Previous Language:

A summary of any emergency response violations cited by MNOPS along with a description of the violation and remediation in each circumstance.

And

The number of violation letters received by the utility from MNOPS.[24]

Integrity Management Plan Reporting

Two Commission Orders detail the integrity management plan information required to be included within Gas Utilities' service quality reports. First, the Commission's November 14, 2019, Order[25] requires the gas utilities to provide information based on their filings under 49 CFR 192.1007 (e)[26] which includes the following information:

- Number of hazardous leaks either eliminated or repaired as required by 49 CFR § 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;
- Number of excavation damages;
- Number of excavation tickets (receipt of information by the underground facility operator from the notification center);
- Total number of leaks either eliminated or repaired, categorized by cause; and
- Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material.

Second, the Commission's January 7, 2020 Order[27] required CenterPoint to include distribution integrity management plan ("DIMP") and transmission integrity management plan ("TIMP")[28] data in its service quality reports that address the 9 metrics and 25 sub-metrics developed in an affiliated interest docket.[29] As a part of the same Order, the Commission required Xcel, MERC, GMG, and Great Plains to file DIMP/TIMP data based on several of the metrics created for CenterPoint, including:

[24] See April 12 2019 Order in Dockets G-002/M-18-316, G-008/M-18-312, G-004/M-18-286, and G-022/M-18-314 as well as January 7, 2020 Order in Docket No. G-011/M-19-303

[25] Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280.

[26] 49 CFR 192.1007 (e) states that a written integrity management plan must contain "performance measures from an established baseline to evaluate the effectiveness of an integrity management program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks."

[27] Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[28] The federal Pipeline Safety Improvement Act of 2002 and implementing regulations require operators of natural-gas transmission and distribution pipelines to implement programs to assess and improve the safety, reliability, and integrity of their natural-gas infrastructure. These Programs are known as distribution, and transmission integrity management programs. (*See 49 C.F.R. pt. 192 subps. O and P).*

[29] CenterPoint, along with the OAG and the Department, reached agreement in a separate affiliated interest agreement docket on reporting metrics for evaluating the cost-effectiveness of safety and reliability infrastructure

- Leak count by facility type and threat:
    - Total count by cause – above ground
    - Total count by cause – mains
    - Total count by cause – services
- Leak count on main my material
- Leak count on service by material

The NGWG notes that because a gas utility's excavation damages and excavation tickets required by the Commission's November 14, 2019, Order are already reported elsewhere within Gas Utilities' service quality reports, the Commission's Integrity Management Plan and DIMP/TIMP reporting requirements are effectively gathering information on the quantity and severity of detected leaks in a given year.

Gas Utility DIMP and TIMP reports are not standardized, and so each Gas Utility reports different information. CenterPoint's DIMP and TIMP gas service quality reporting requirements were developed specifically for CenterPoint based on the information the Company includes within its DIMP and TIMP reports. These were not initially intended to serve as standardized reporting requirements, and other Minnesota Gas Utilities were not involved in their development.

However, despite this, the Office of the Attorney General ("OAG"), which was a participant in CenterPoint's affiliated interest docket, recommended that CenterPoint's DIMP/TIMP metrics be adopted by all the Gas Utilities, noting that such information would allow the Commission, and other interested parties, to more fully scrutinize the DIMP and TIMP project costs included in MERC, Xcel, and Great Plain's gas utility infrastructure cost ("GUIC") riders.[30,31]

The NGWG notes that decisions on the recovery of DIMP and TIMP project costs occur within individual utilities' GUIC rider dockets, or as a part of general rate case proceedings. Commission staff, as a member of the NGWG, confirmed that the DIMP and TIMP information provided annually in Gas Utilities' service quality reports are not utilized for GUIC riders or general rate cases. Utilities already provide all relevant information within those individual dockets.

The NGWG believes that leak reporting could be standardized and have a greater impact on the evaluation of a utility's quality of service if the reporting requirements were modified to more closely align with the information utilities provide PHMSA as a part of their annual distribution reports. All Minnesota Gas Utilities provide PHMSA with the same information through their Annual Gas Distribution Reports. Aligning the Gas Utilities' leak reporting requirements with the PHMSA annual reports would remove previously required DIMP/TIMP information that is not collected by each utility, including the number of above ground leaks, leaks by material, and hazardous leaks by material.

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investments. See *In the Matter of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas (the Company), for Approval of an Affiliated Interest Agreement between CenterPoint Energy and Minnesota Gas and Minnesota Limited, Docket No. G-008/AI-18-517, Commission Order (January 14, 2019).*

[30] See June 17, 2019 OAG Comments in Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[31] Through GUIC riders, utilities get expedited recovery of DIMP and TIMP project costs.

However, the NGWG does not believe that leak data could serve as a comparable metric and would advise against drawing conclusions across utilities. As was previously mentioned, there are many factors that impact the number of leaks reported by a utility each year, including the section of the distribution system being surveyed in a given year, the frequency of leak surveys, the amount of excavation that occurred in a given year, the leak survey technology being used, and more.

Although these uniform metrics are not necessarily comparable, adopting the NGWG's recommended reporting requirements would allow for Commission staff to more accurately display the service quality performance of several utilities on a single graph. Such figures are becoming more common since Commission staff began writing a single briefing paper to cover all five utilities' service quality reports.

The Department stated a preference for keeping the current integrity management plan reporting requirements and will be available to answer any questions about its position at the Commission's agenda meeting discussing this docket.

The NGWG does not take a position on CenterPoint's utility-specific DIMP/TIMP reporting requirements developed and agreed upon as a part of its affiliated interest docket. Instead, the NGWG's recommendation is intended for the other four Gas Utilities. Finally, the NGWG notes that the Commission's June 1st, 2021, Order Establishing Frameworks for Implementing NGIA in Docket No. G-999/CI-21-566 requires the DIMP/TIMP metrics reported in gas service quality reports be included in Natural Gas Innovation Act ("NGIA") Plans.

Recommendation:

Going forward, Xcel Energy, MERC, GMG, and Great Plains shall report the following metrics from their Annual PHMSA Distribution Reports in their service quality reports in place of any previously ordered Integrity Management Plan, Distribution Integrity Management Plan, and Transmission Integrity Management Plan reporting requirements:

- *Miles of Distribution Main*
- *Number of Main Leaks*
- *Number of Main Leaks by Cause*
- *Number of Hazardous Main Leaks by Cause*
- *Main Leaks per 1,000 Miles of Main*
- *Number of Services*
- *Number of Service Leaks*
- *Number of Service Leaks by Cause*
- *Number of Hazardous Service Leaks by Cause*
- *Service Leaks per 1,000 Services*

Previous Language:

> *Require utilities to file, based on their filing under 49 CFR 192.1007 (e) and the baseline information provided on May 1, 2019, an update of: integrity management plan performance measures; monitoring results; and evaluation of effectiveness.*[32]
>
> *And*
>
> *Xcel, MERC, GMG, and Great Plains must annually file, as part of their natural gas service quality reports, TIMP/DIMP data in categories 1–3 in the table above, which includes leak count by facility type and threat; leak count on main by material; and leak count on service by material.*[33]

Public-Facing Summaries of Service Quality Reports

As a part of the NGWG's effort to improve the transparency and accessibility of service quality information, the NGWG reviewed electric utilities service reliability and service quality ("SRSQ") public facing summaries and discussed whether similar documents could be adopted for use in Gas Service Quality Reports.

Currently, Minnesota's investor-owned electric utilities are required to file public facing summaries of their annual SRSQ reports and publish those summaries in locations visible to customers.[34] These public facing summaries are two pages in length and typically contain a map displaying the utilities' service territory, information on how to reach customer service, service interruption data, call center response data, and service extension data. There have been no Commission orders detailing what information is required to be included within these public facing summaries.

After discussing the Electric Utilities' public facing summaries, the NGWG was unable to come to a consensus on whether Gas Utilities should provide public facing summaries as a part of their service quality reports. Public facing summaries would improve the transparency and accessibility of gas service quality data. However, the NGWG debated whether such information would be beneficial and/or reassuring to the public given the negative press currently surrounding the natural gas industry. For instance, although the Gas Utilities, the Department, and the Commission may be comfortable with the number of leaks being reported on the gas system and a utility's emergency response time, a member of the public who is fearful of natural gas may review this information and conclude that the utility has poor service quality.

Should the Commission be interested in continuing to explore public facing summaries of gas service quality reports, the NGWG would recommend that the Commission first receive cost estimates from each utility to better understand the costs associated with developing and producing such reports on an annual basis. Additionally, the Commission may wish to request that electric utilities share information

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[32] November 14, 2019 Order in Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[33] January 7, 2020 Order in Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[34] December 2, 2021 Order in Docket Nos. E-015/M-21-230, E-017/M-21-225, and E-002/M-21-237

on how many times their public facing summaries are being accessed on their websites by members of the public. This would allow the Commission to understand the demand for these types of public facing summaries, and the cost to produce them.

Utility Web-Based Metrics

Background

In response to recommendations by the Department, the Commission's August 5, 2022, Orders[35] required the Gas Utilities to propose web-based service metrics similar to those required of electric utilities by September 1, 2022, as a supplemental filing in their 2021 gas service quality report dockets.

On September 1, 2022 the Gas Utilities submitted a joint compliance filing in which they outlined their proposed web-based metrics, which included the following information:

- The uptime percentage for their general websites and payment services
- The error rate percentage for their payment services
- The yearly total number of website visits;
- The yearly number of logins via electronic customer communication platforms
- The yearly number of emails or other customer service electronic communications received;
- And a categorization of email subject and electronic customer service communications by subject, including categories for communications related to assistance programs and disconnections as part of reporting under Minnesota Rule 7826.1700.

In their filing, the Gas Utilities explained that there may be situations in which a utility would be unable to utilize an automated method to provide the web-based metrics. The Gas Utilities explained that, in such situations, a Gas Utility should be exempt from providing that particular metric as it would be unreasonable for the utility to manually tabulate the metrics.

The Commission responded to the Gas Utilities' proposed metrics in its May 1, 2023 Order, in which the Commission requested that the Gas Utilities jointly file a reporting template for the requested information within 90 days of Order's issuance. The reporting template was to include:

- A uniform list of customer service electronic communication types
- A uniform list of subject matter for which to categorize email or customer service communications based on the complaint reporting categories outlined in Minn. R. 7826.2000 when feasible.

This request was in response to Commission staff's observation that the communication categories utilized in electric utilities' web-based metrics differed both across utilities, and across reporting years for some individual utilities. Staff suggested that consistency in reporting categories would allow the Commission to better understand how the customers of each Gas Utility interact with their utility through web-based means, and how these interactions differ between the customers of each utility.

[35] Docket Nos. G-002/M-21-301, G-008/M-21-303, G-022/M-21-304, G-004/M-21-300, and G-011/M-21-313

On August 1st, 2023 the Gas utilities requested an extension, which was approved by the Commission. The extension allows for the Utilities' response to the Commission's May 1, 2023, Order to be included in the NGWG's final report. The Utilities' response is provided below.

Gas Utilities' Proposal for Web-Based Metrics

After further discussion within the NGWG, the Gas Utilities recommend to report:

- The percentage of uptime of the utility's enterprise-wide website (may not be state specific)
- The percentage of uptime for web payment services ability (defined as the percentage of time that web payment services are available to some customers on utility-based platforms)
- The error rate percentage for the utility-based payment services (defined as payment processing error rate – does not include errors outside of the utility's control such as non-sufficient funds ("NSF"), expired customer debit or credit cards, etc.)
- The yearly total number of website visits to initial facing enterprise-wide website (may not be state specific);
- The yearly number of logins via electronic customer communication platforms (to include enterprise-wide website and mobile apps, if applicable; may not be state specific and provides combined total for all customer logins, regardless of platform)

Based on the review of the various systems each of the Gas Utilities utilize, it was determined that the utilities have the ability to report on the web metrics listed above. To the extent that the metrics identified herein differ from those identified by the Gas Utilities in their September, 2022 joint filing, the Gas Utilities believe that these metrics are most appropriate because they are more well-suited to serve the Commission's purpose of providing meaningful information to review that can be reported by the Gas Utilities without unduly burdensome manual tabulation.

Summary of Conclusions and Recommendations

The NGWG supports the conclusion of the Gas Utilities' supplemental discussion on comparative metrics that there are no already existing gas service quality metrics and associated databases that would allow for the comparison of one Gas Utility's service quality to other similarly sized utilities across the nation. The NGWG has found that, in some instances, currently reported service quality metrics could be modified to standardize the information being reported by each utility. Such standardization ensures that figures displaying multiple utilities' service quality performance are accurate, and, in the case of excavation damages, could allow for cross utility comparisons.

However, the NGWG does still advise caution before drawing conclusions about one utility's service quality performance by comparing it to another utility's performance. Differences in utility size, geographic area, and business models make it difficult to accurately compare gas utilities' service quality performance.

With that said, the NGWG recommends the Commission make several changes to the reporting requirements for Gas Utilities' service quality reports:

1. Require the Gas Utilities to append their annual PHMSA Gas Distribution Reports to all future Gas Service Quality Reports.

2. Require the Gas Utilities to provide data on involuntary Service Disconnections by appending their December Residential Customer Status Reports, including data for January through December as filed in Docket No. E,G-999/PR-YY-02, in their annual service quality reports. Utilities shall also provide a narrative explanation of their involuntary service disconnection performance, as needed, including steps taken to improve performance in the future.

3. In place of any prior Customer Deposit reporting requirements, require that Utilities report on Customer Deposits within their annual service quality reports anytime their deposit collection policies change. These reports shall include a description of the previous deposit collection policy, a description of the new deposit collection policy, the reason for the policy change, and data from the previous three years regarding the number of customers who were required to make a deposit as a condition of receiving service and the total number of deposits held at the end of each year.

4. In place of the mislocate and system damage reporting requirements set by the Commission's August 26, 2010 Order in Docket No. G999/CI-09-409, require the Gas Utilities to report on excavation damages within their Annual Service Quality Reports using the following metrics:

   a. The number of excavation tickets received;
   b. The number of excavation damages;
   c. The number of excavation damages per 1,000 excavation tickets; and
   d. The number of at fault damages.

   An "at fault damage" shall be defined as a damage where the root cause of the damage falls under the responsibility of the utility or its contractors including mislocates made by the company or its contract locating companies.

5. Going forward, the Gas Utilities shall no longer be required to provide information on customer service operation and maintenance expenses in their annual service quality reports pursuant to Order Point 2.O. of the Commission's August 26, 2010 Order in Docket No. G-999/CI-09-409.

6. Allow the Gas Utilities to confirm with the Commission that they have completed their EFV and manual shut-off valve outreach pursuant to the Commission's July 31, 2019 Order in Docket No. 18-41. Upon receiving confirmation from the Commission, utilities that have competed their EFV and manual shut-off valve outreach may cease annual reporting on EFVs, manual shut-off valves and related outreach in their annual service quality reports, including the reporting of EFV and manual shut-off valve data pursuant to the Commission's November 14, 2019 Order in Docket Nos. G-004/M-19-280, G-004/M-19-300, G-011/M-19-303, and G-002/M-19-305. Utilities shall continue appending their annual PHMSA reports to their service quality reports, which contains information on the number of EFVs and manual shut-off valves installed on their system.

7. In place of prior reporting requirements on MNOPS violations and violation letters, the Gas Utilities shall instead provide a summary of any violations cited by MNOPS along with a description of the violation and remediation in each circumstance, and a count of violations by citation code within their Annual Service Quality Reports.

8. Going forward, Xcel Energy, MERC, GMG, and Great Plains shall report the following metrics from their Annual PHMSA Distribution Reports in their service quality reports in place of any previously ordered Integrity Management Plan, Distribution Integrity Management Plan, and Transmission Integrity Management Plan reporting requirements:
   a. Miles of Distribution Main
   b. Number of Main Leaks
   c. Number of Main Leaks by Cause
   d. Number of Hazardous Main Leaks by Cause
   e. Main Leaks per 1,000 Miles of Main
   f. Number of Services
   g. Number of Service Leaks
   h. Number of Service Leaks by Cause
   i. Number of Hazardous Service Leaks by Cause
   j. Service Leaks per 1,000 Services

The NGWG believes that utilities' annual service quality reports are an appropriate venue for additional discussions surrounding Gas Utilities' reporting requirements for their Service Quality Reports, especially for utilities with utility-specific reporting requirements who wish to modify their specific reporting requirements.

Regarding web-based metrics, the Gas Utilities recommend the following:

9. Beginning with their 2024 service quality reports (filed in 2025) the Gas Utilities shall report the following web-based metrics within their annual service quality reports:
   a. The percentage of uptime of the utility's enterprise-wide website (may not be state specific)
   b. The percentage of uptime for web payment services ability (defined as the percentage of time that web payment services are available to some customers on utility-based platforms)
   c. The error rate percentage for the utility-based payment services (defined as payment processing error rate – does not include errors outside of the utility's control such as non-sufficient funds ("NSF"), expired customer debit or credit cards, etc.)
   d. The yearly total number of website visits to initial facing enterprise-wide website (may not be state specific);
      i. The yearly number of logins via electronic customer communication platforms (to include enterprise-wide website and mobile apps, if applicable; may not be state specific and provides combined total for all customer logins, regardless of platform)

Sincerely,

/s/ Bridget Dockter
Manager, Policy & Outreach
Xcel Energy

/s/ Emily Suppes
Director, Regulatory Affairs
CenterPoint Energy Minnesota Gas

/s/ Richard Stasik
Director – State Regulatory Affairs
Minnesota Energy Resources Corporation

/s/ Travis R. Jacobson
Director of Regulatory Affairs
Great Plains Natural Gas Company

/s/ Kristine A. Anderson
Corporate Attorney
Greater Minnesota Gas, Inc.

/s/ Trey Harsch
Rates Analyst II
Minnesota Public Utilities Commission

/s/ John Kundert
Financial Analyst
Minnesota Department of Commerce

Attachment 1

Summary of Current Gas Service Quality Reporting Requirements

Summary of Current Gas Service Quality Reporting Requirements

Call Center Response Time

Utilities, excluding GMG, report:[36]

- The percent of calls answered within 20 seconds as described in Minn. Rules part 7826.1200;[37] and
- The average time required to answer an incoming call.
- CenterPoint will continue reporting IVR "zero-out" data[38]

GMG reports:[39]

- The total number of phone calls received during each annual reporting period; and
- The number of time a phone rings before it is answered.

Meter Reading Performance

As described in *Minn. Rules, part 7826.1400,* regulated gas utilities report:[40]

- The number and percentage of customer meters read by utility personnel;
- The number and percentage of customer meters self-read by customers;
- The number and percentage of customer meters that have not been read by utility personnel for periods of six to 12 months and for periods of longer than 12 months, and an explanation as to why they have not been read; and
- Data on monthly meter reading staffing levels, by work center or geographical area.

MERC's reports include data both with and without farm tap account information.[41]

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[36] August 26, 2010 Order, Docket No. G999/CI-09-409

[37] "Utilities shall answer 80 percent of calls made to the business office during regular business hours within 20 seconds. 'Answer' means that an operator or representative is ready to render assistance or accept the information to handle the call. Acknowledging that the customer is waiting on the line and will be served in turn is not an answer. If the utility uses an automated call-processing system, the 20-second period begins when the customer has selected a menu option to speak to a live operator or representative. Utilities using automatic call-processing systems must provide that options, and they must not delay connecting the caller to a live operator or representative for purposes of playing promotional announcements" – Minn. Rule 7826.1200 subd. 1

[38] November 25, 2015 Order, Docket No. G-008/M-15-414

[39] January 18, 2011 Order, Docket No. G999/CI-09-409

[40] August 26, 2010 Order, Docket No. G999/CI-09-409

[41] Id.

Additionally, utilities will explain whether the difference between the total percentage of meters (100%) and the percentage of meters read (by both the utility and customers) is equal to the percentage of estimated meter reads.[42]

Involuntary Service Disconnection Data

In lieu of reporting data on involuntary service disconnections as contained in Minn. Rules, part 7826.1500, each utility references the data that it submits under Minn. Stat. §§ 216B.091 and 216B.096 which includes:[43]

- Number of customers
- Number and total amount of accounts past due amount
- Total revenue received from the low-income home energy assistance program and other sources contributing to the bills of low-income person
- Average monthly bill
- Total sales revenue
- Total write-offs due to uncollected bills
- The number of disconnection notices mailed
- The number of accounts disconnected for nonpayment
- The number of accounts reconnected to service
- The number of accounts that remain disconnected, grouped by the duration of disconnection, as follows
    - 1-30 days
    - 31-60 days
    - And more than 60 days
- Monthly reports for October through April must also include:
    - Number of cold weather protection requests
    - Number of payment arrangement requests received and granted
    - Number of rights to appeal notices mailed to customers
    - Number of reconnect requests appeals withdrawn
    - Number occupied heat-affected accounts disconnected for 24 hours or more for electric and natural gas service separately
    - Number occupied non-heat-affected accounts disconnected for 24 hours or more for electric and gas service separately
    - Number of customers granted cold weather rule protection
    - Number of customers disconnected who did not request cold weather rule protection

[42] March 6th, 2012 Order, Docket Nos. G002/M-11-360, G-001/M-11-361, G-004/M-11-363, G-007,011/M-10-374, G-008/M-10-378, and G-022/M-11-356

[43] August 26, 2010 Order, Docket No. G999/CI-09-409

  - Number of customers disconnected who requested cold weather rule protection
- The number of utility heating service customers whose service is disconnected or remains disconnected for non-payment as October 1 and October 15. If customers remain disconnected on October 15, a utility must file a report each week between November 1 and the end of the cold weather period specifying:
  - The number of utility heating service customers that are or remain disconnected from service for non-payment
  - The number of utility heating service customers that are reconnected to service each week.

Service Extension Requests

As described by *Minn. Rules, part 7826.1600, items A and B* utilities, excluding GMG, report:[44]

- The number of customers requesting a service extension by customer class
  - The interval between the date service was installed and the latter of the customer-requested in-service date or the date the premises were ready for service
- The number of customers requesting service at a location previously served by the utility
  - The interval between the date service was installed and the latter of the customer-requested in-service date or the date the premises were ready for service

Additionally, these same utilities report:[45]

- The types of extension requests, such as requests for reconnection after disconnection for nonpayment, for both locations previously served and not previously served.

GMG reports:[46]

- Information on extensions to new service areas;
- The addition of new customers on existing mains;
- A discussion of requests for change in service to areas already served by the company;
- Copies of advertisements to potential new customers;
- The date deposits were first taken for a new service area; and
- An explanation of why customers along existing mains and services were denied service.

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[44] August 26, 2010 Order, Docket No. G999/CI-09-409

[45] March 6th, 2012 Order, Docket Nos. G002/M-11-360, G-001/M-11-361, G-004/M-11-363, G-007,011/M-10-374, G-008/M-10-378, and G-022/M-11-356

[46] April 8th 2016 Order, Docket No. G022/M-15-1090

Customer Deposits

As described by Minn. Rules part 7826.1900, utilities report:[47]

- The number of customers who were required to make a deposit as a condition of receiving service.

Additionally, utilities report:[48]

- The different types of deposits included in the reported number of "required deposits"

Customer Complaints

As described by Minn. Rules part 7826.2000, utilities excluding GMG, report:[49]

- The number of complaints received
- The number and percentage of complaints alleging:
    - Billing errors
    - Inaccurate metering
    - Wrongful disconnection
    - High bills
    - Inadequate service
    - Involving service extension intervals
    - Service-restoration intervals
    - Any other identifiable subject matter involved in five percent or more of customer complaints
- The number and percentage of all complaints resolved by taking any of the following actions:
    - Taking the action the customer requested
    - Taking an action the customer and the utility agree is an acceptable compromise
    - Providing the customer with information that demonstrates that the situation complained of is not reasonably within the control of the utility
    - Refusing to take the action the customer requested
- The number of complaints forwarded to the utility by the Commission's Consumer Affairs Office for further investigation and action.

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[47] August 26, 2010 Order, Docket No. G999/CI-09-409

[48] March 6th, 2012 Order, Docket Nos. G002/M-11-360, G-001/M-11-361, G-004/M-11-363, G-007,011/M-10-374, G-008/M-10-378, and G-022/M-11-356

[49] August 26, 2010 Order, Docket No. G999/CI-09-409

GMG reports:[50]

- Complaints received from CAO
- The total number of complaints resolved for each of the following categories:
  - Billing errors
  - Inaccurate metering
  - Wrongful disconnection
  - High bills
  - Inadequate service
  - Service extension intervals
  - Service restoration intervals

Additionally, Utilities must include customer complaint data from Minnesota Rules 7820.0500 in their Annual Service Quality Reports.[51]

Gas Emergency Phone Line Answer Time

Utilities report:[52]

- Telephone answer times to the utility's gas emergency phone line.

GMG will report:[53]

- The total number of gas emergency calls received.

Gas Emergency Response Times

Utilities report:[54]

- The percentage of emergencies responded to within one hour and within more than one hour.
- The type of gas emergency calls included in the summary of gas emergency response times.

[50] January 18, 2011 Order, Docket No. G999/CI-09-409

[51] January 18, 2023 ,Docket Nos. E,G-999/PR-22-13, E-111/M-22-168, E-015/M-22-163, E-017/M-22-159, E-002/M-22-162, G-004/M-22-211, G-022/M-22-193, G-011/M-22-219, and G-002/M-22-210

[52] August 26, 2010 Order, Docket No. G999/CI-09-409

[53] January 18, 2011 Order, Docket No. G999/CI-09-409

[54] August 26, 2010 Order, Docket No. G999/CI-09-409

Additionally, Xcel, CenterPoint, and MERC shall report:[55]

- The average number of minutes it takes to respond to an emergency.

Mislocates

Utilities report:[56]

- The number of times a line is damaged due to mismarked line or failure to mark a line.

Gas Line Damages

Utilities report:[57]

- The number of gas lines damaged, with damage categorized according to whether it was:
  - caused by the utility's employees or contractors, or
  - if it was due to an unplanned cause.

Service Interruptions

Utilities, excluding GMG, report:[58]

- The number of service interruptions categorized according to whether it was:
  - caused by the utility's employees or contractors, or
  - whether it was due to any unplanned cause.

Additionally, these utilities report:[59]

- The number of customers whose service was interrupted.
- The average duration of interruptions.

GMG reports:[60]

- The number of unplanned service interruptions for outages due to:

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[55] Id.

[56] Id.

[57] August 26, 2010 Order, Docket No. G999/CI-09-409

[58] August 26, 2010 Order, Docket No. G999/CI-09-409

[59] March 6th, 2012 Order, Docket Nos. G002/M-11-360, G-001/M-11-361, G-004/M-11-363, G-007,011/M-10-374, G-008/M-10-378, and G-022/M-11-356

[60] January 18, 2011 Order, Docket No. G999/CI-09-409

    - Low system pressure
    - Third party damage
    - Other causes
- The number of customers affected by each outage
- The number of outages caused by GMG's employees or contractors

Major Incident Reporting

Utilities report:[61]

- Summaries of major events that are immediately reportable to the Minnesota Office of Pipeline Safety (MNOPS) according to the criteria used by MNOPS to identify reportable events.[62]
- Each summary shall include the following items:
    - The location
    - When the incident occurred
    - How many customers were affected
    - How the company was made aware of the incident
    - The root cause of the incident
    - The actions taken to fix the problem
    - What actions were taken to contact customers
    - Any public relations or media issues
    - Whether the customer or the company relighted
    - The longest any customer was without gas service during the incident.

Customer-service Related Operations and Maintenance Expenses

Utilities Report:

- Customer-service related operations and maintenance expenses. The reports shall only include Minnesota-regulated, customer-service expenses and shall be based on the

[61] August 26, 2010 Order, Docket No. G999/CI-09-409

[62] The MOPS criteria for a reportable event is the release of natural gas causing any of the following: (1) Evacuation of 10 or more people, (2) Evacuation of a school, hospital or health care facility, (3) Rerouting of traffic or closing a highway by public emergency responders, (4) 50 or more customers out of service, (5) Media attention, and (6) Unintentional fire or explosion. In addition, for natural gas and liquified natural gas (LNG) per CFR Title 49 Part §191.3, Definitions, a reportable incident means any of the following: (1) An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and (i) A death, or personal injury necessitating in-patient hospitalization; or (ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more. (2) An event that results in an emergency shutdown of a LNG facility. (3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2). – (April 29, 2010 Staff Briefing Papers, Docket No. G999/CI-09-409)

costs each utility records in its FERC accounts 901 and 903, plus payroll taxes and benefits.

Integrity Management Plans

Utilities report:[63]

- Based on the utility's filing under 49 CFR 192.1007 (e): and the baseline information provided on May 1, 2019, an update of: integrity management plan performance measures; monitoring results; and evaluation of effectiveness.

  Staff notes that this includes the following information:
    - Number of hazardous leaks either eliminated or repaired as required by 48 CFR 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;
    - Number of excavation damages;
    - Number of excavation tickets (receipt of information by the underground facility operator from the notification center);
    - Total number of leaks either eliminated or repaired, categorized by cause; and
    - Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material

Distribution and Transmission Integrity Management Plans (DIMP/TIMP)

CenterPoint is required to:[64]

- annually file TIMP/DIMP data addressing the 29 metrics developed in its affiliated interest docket,[65] updating three-year averages each year.

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[63] November 14, 2019 Order, Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[64] January 7, 2020 Order, Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[65] CenterPoint, along with the OAG and the Department, reached agreement in a separate affiliated interest agreement docket on reporting metrics for evaluating the cost-effectiveness of safety and reliability infrastructure investments. See *In the Matter of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas (the Company), for Approval of an Affiliated Interest Agreement between CenterPoint Energy and Minnesota Gas and Minnesota Limited, Docket No. G-008/AI-18-517, Commission Order (January 14, 2019).*

Xcel, MERC, GMG, and Great Plains shall report TIMP/DIMP including the following information:[66]

- leak count by facility type and threat;
- leak count on main by material; and
- leak count on service by material.

EFV and Manual Shut-off Valves

Utilities, excluding GMG, shall report:[67]

- The number of customers suitable for EFVs;
- The number of EFVs installed;
- The number of customers who requested an EFV be installed;
- The percent of suitable customers with an EFV installed;
- The number of customers unsuitable for an EFV;
- The number of customers suitable for manual shut-off valves;
- The number of manual shut-off valves installed;
- The number of customers who requested a manual shut-off valve be installed; and
- The percent of suitable customer with manual shut-off valves.

All Utilities were authorized to submit remaining reports required by a July 13, 2019 Order (Docket No. 18-41) in their service quality reports. These reports detail utility progress toward holding face-to-face meetings with the decision makers of specified customers regarding the installation of EFVs and manual service line shut off valves in eligible buildings within the utility's service territory. Reports are due through the 2025 reporting period.

MNOPS Emergency Response Violations and Violation Letters Received from MNOPS

Utilities shall report:[68]

- A summary of any emergency response violations cited by MNOPS along with a description of the violation and remediation in each circumstance.

[66] January 7 2020 Order, Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280

[67] November 14 2019 Order, Docket Nos. G-022/M-19-304, G-002/M-19-305, G-008/M-19-300, G-011/M-19-303, and G-004/M-19-280.

[68] April 12 2019 Order in Dockets G-002/M-18-316, G-008/M-18-312, G-004/M-18-286, and G-022/M-18-314 as well as January 7, 2020 Order in Docket No. G-011/M-19-303.

- The number of violation letters received by the utility from MNOPS for the year in question

Web-Based Metrics

- TBD

Utility-Specific Requirements

Xcel: Meter Equipment Malfunctions (Field Orders)

Xcel reports:[69]

- Volume of investigation and Remediate
- Volume of investigate and refer
- Volume of remediate upon referral field orders
- Average response time for each of the above categories by month and year
- Minimum days, maximum days, and standard deviation for each category
- Volume of excluded field orders

CenterPoint: Steel Service Line Relocation

CenterPoint reports:[70]

- Annual compliance filings showing for each steel service line relation and each relocation of meters rated at 630 cubic feet per hour (CFH) or greater:
    - The itemized costs associated with each relocation

CenterPoint: Additional Call Center Detail

CenterPoint reports:[71]

[69] November 30, 2010 Order in Docket No. G002/CI/08-871

[70] March 15, 2010 Order in Docket No. G008/M-09-1190

[71] June 8, 2005 Order in Docket No. G008/GR-04-901

- The information contained in its Minn. Rule 7820.0500 annual report on Public Utilities Commission "formal" complaints on a quarterly basis, and provide the same information on a quarterly basis for complaints from other state agencies and the Better Business Bureau.
- The total number of calls its call center receives
- The number of these calls that come into the dedicated line for emergencies, billing inquiries, credit/payment arrangements, and service connection/disconnection requests.

Attachment 2

Delaware's Natural Gas Service Reliability and System Planning Standards

DEPARTMENT OF STATE

PUBLIC SERVICE COMMISSION

8000 Gas Regulations

8003 Natural Gas Service Reliability and System Planning Standards

EFFECTIVE DATE: October 11, 2020

1.0 Purpose and Scope

1.1 Natural gas system safety is the overriding goal for Delaware's natural gas system operators. Reliable natural gas service is an essential service to Delaware citizens and is of great importance to the Delaware Public Service Commission ("Commission"). This regulation sets forth distribution planning requirements, reliability standards, and reporting requirements to assure the continued Reliability and Natural Gas quality of service being delivered to Delaware regulated public utility customers and applies to all Delaware Gas Distribution Companies ("GDCs").

1.2 Nothing in this regulation relieves a GDC from compliance with any requirement set forth under any other regulation, statute or order, such as the GDC's operations, maintenance and emergency manuals, federal pipeline safety regulations contained in 49 CFR Part 192 and Delaware Pipeline Safety Compliance Programs.

1.3 Compliance with this regulation is a minimum standard. Compliance does not create a presumption of safe, adequate and proper service. Each GDC must exercise its professional judgment based on its systems and service territories. Nothing in this regulation relieves any GDC from the requirement to furnish safe, adequate and proper service and to keep and maintain its property and equipment in such condition as to enable it to do so. (26 **Del.C.** §209)

1.4 Each GDC is responsible for maintaining the Reliability of natural gas service to all its customers in the state of Delaware. Pursuant to this requirement, GDCs may be subject to penalties as provided for in Section 10.0 or allowed under other applicable Delaware law.

1.5 GDCs are encouraged to explore the use of proven state of the art technology, to provide cost effective natural gas service Reliability improvements.

2.0 Definitions

The following words and terms, as used in these Regulations, shall have the following meanings, unless the context clearly indicates otherwise:

"**Acceptable reliability level**" means the minimum acceptable level of natural gas service based on the targets set for Annual Outage Rate (AOR) and Average Outage Duration (AOD), as set forth in these regulations.

"**Annual outage rate**" or "**AOR**" means the frequency of sustained customer outages during the reporting year. AOR can be expressed as "events per customer per year" and defined as:

$$AOR = \frac{\text{Total Number of Sustained Customer Outages per Reporting Period}}{\text{Total Number of Customers}}$$

"**Average outage duration**" or "**AOD**" means the average time in minutes required to restore service to those customers that experienced sustained outages during the reporting period. AOD is defined as follows:

$$AOD = \frac{\text{Sum of all Sustained Customer Outage Durations per Reporting Period}}{\text{Total Number of Sustained Customer Outages per Reporting Period}}$$

"**Benchmark**" means the standard service measure of AOR and AOD as set forth in these regulations.

"**Capacity**" means the rated continuous load-carrying ability, expressed in Volume ("V"), of pipelines, regulators, or other gas equipment.

"**Commission**" or "**PSC**" means the Delaware Public Service Commission.

"**Corrective actions**" means the maintenance, repair, or replacement of a GDC's utility system components and structures to allow them to function at an acceptable level of reliability.

"**Delivery Facilities**" means the GDC's physical natural gas distribution system used to provide gas service to Delaware retail customers, normally inclusive of Distribution and Transmission Facilities. A GDC that typically operates at pressures of 200 psi or below and that are used to deliver natural gas to customers, up through and including the point of physical connection with natural gas facilities owned by the customer.

"**DPA**" means the Delaware Division of the Public Advocate.

"**Gas distribution company**" or "**GDC**" means a public utility owning or operating natural gas transmission and/or Distribution Facilities in Delaware.

"**Major reliability event**" means an outage of 1000 customers or more that is caused by a loss of natural gas pipeline supply or a weather event. Major reliability event outages shall be excluded from the GDC's AOR, and AOD calculations for comparison to reliability benchmarks. Outage data for major reliability events shall be collected and reported according to the reporting requirements set forth in this regulation.

"**Natural gas distribution system**" means that portion of a natural gas system that delivers gas energy from tap stations on the transmission system to points of connection at the customers' premises.

"**Natural gas quality**" means the characteristics of natural gas received by the customer. Characteristics of gas service that detract from its quality include liquids and particulates from the processing of natural gas upstream and compression of gas in transmission systems supplying gas to the GDC, either prolonged or transient. Natural gas quality problems shall include, but are not limited to, disturbances such as high or low pressure, moisture control, compressor oil carryover, and sulfur.

"**Natural gas service**" means the supply, transmission, and distribution of natural gas energy as provided by a GDC.

"**Outage**" means the loss of natural gas service to one or more customers. It is the result of a planned maintenance activity or one or more unplanned component failures, depending on system configuration or other events. Types of outages include planned and unplanned.

"**Outage, duration**" means the period (measured in minutes) from the initiation or report of a loss of natural gas service to a customer until such service has been restored to that customer.

"**Outage management system**" or "**OMS**" means a software system that provides database information to effectively manage service interruptions and minimize customer outage times.

"**Outage, planned**" means a loss of natural gas service that results when one or more components are deliberately taken out of service at a selected time, usually for the purposes of preventive maintenance, repair or construction. Where attempts have been made to notify customers in advance, planned outages shall not be included in reliability calculations.

"**Outage, sustained**" means a loss of natural gas service to one or more customers that is longer than 30 minutes in duration.

"**Outage, unplanned**" means a loss of natural gas service that results when one or more components are out of service at a selected time, usually as a result of a weather event, low pressure condition, water infiltration or some other unexpected operational event or outside force.

"**Pipeline**" means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

"**Related projects**" means individual projects whose completion is required, contingent, or dependent on each other for overall completion of the specified scope of work.

"**Reliability**" means the degree of performance of the elements of the natural gas system that results in gas being delivered to customers within accepted standards. Reliability may be measured by the frequency and duration of adverse effects on natural gas distribution service.

"**Restored**" means that gas service is available at the customer's premise and all GDC equipment, up to and including the meter, is gassed up. For inaccessible meters and customers that are not ready for service, the outage will be considered corrected when the GDC has attempted to restore gas to the customer.

"**Staff**" means the Staff of the Delaware Public Service Commission.

"**Sum of all sustained customer outage durations**" means the summation of the restoration time (in minutes) for each customer outage during the reporting period.

"**Total number of customers served**" means the number of customers provided with gas service by the distribution facility for which a reliability measure is being calculated on the last day of the time period for which the reliability measure is being calculated.

"**Total number of sustained customer outages**" means the sum of the number of customer outages for each outage event during the reporting period. Customers who experienced multiple outages during the reporting period are counted for each outage event the customer experienced during the reporting period.

"**Transmission facilities**" means natural gas facilities located in Delaware and owned by a GDC that operate at pressures above 200psi and that are used to transmit and deliver natural gas to customers up through and including the point of physical connection with gas facilities owned by the customer.

3.0 Gas Service Reliability and System Planning

3.1 Each GDC shall install, design, construct, operate, and maintain its Delivery Facilities in conformity with the requirements set forth in the GDC's operations, maintenance and emergency manuals, federal pipeline safety regulations contained in 49 Code of Federal Regulations ("CFR") Part 192, and Delaware Pipeline Safety Compliance Programs or their successor organizations.

3.2 Each GDC shall develop and maintain a System Planning and Modeling Program as described in Section 5.0 to ensure the safety, Reliability, and quality of Natural Gas Service of its Natural Gas Distribution System.

4.0 Reliability and Quality Performance Benchmarks

4.1 The measurement of Reliability and quality performance shall be based on annual AOR and AOD calculations. The AOR and AOD calculations shall be derived using criteria outlined in the definitions of AOR and AOD. The AOR and AOD calculations shall include all Delaware customer Outages excluding Major Reliability Events.

4.2 Each GDC shall take measures to maintain its overall gas service Reliability and quality performance within the Benchmark standards that will be determined after GDCs have tracked and reported three years of AOR and AOD metrics data.

4.2.1 The three-year average AOR shall not exceed [placeholder for AOR target] outages. (To be determined after three years of data are available.)

4.2.2 The three-year average AOD shall not exceed [placeholder for AOD target] minutes. (To be determined after three years of data are available.)

4.3 Each GDC will be required to track AOR and AOD metrics beginning on 1/1/2021. After the GDCs submit the Reliability Performance Reports as required in Section 8.0, the Commission shall establish AOR and AOD Benchmarks for each GDC. The Benchmarks will be reviewed annually and may be reset based on each GDC's historical performance, reliability investments and comparisons to other GDCs, if available.

4.4 When performance does not meet the Acceptable Reliability Level, additional monitoring and enforcement actions that may be taken including the following: additional remedial review; requiring additional GDC reporting; conducting an informal investigation; initiating a formal complaint; requiring a formal improvement plan with enforceable commitments; requiring an implementation schedule; and assessing penalties and fines.

5.0 Natural Gas Distribution System Planning and Modeling Program

5.1 Each GDC shall have a robust system planning and modeling program based on natural gas industry best practices designed to review, on an annual basis or more often as needed, issues with the Natural Gas Distribution System affecting safety and Reliability to proactively plan for system improvements to be incorporated in the various plans (annual GDC capital plans and Infrastructure, Safety and Reliability Plans). Best practices that should be incorporated into system planning and modeling programs include:

Best Practice	**Time Frame** Annual (minimum)
Typical system planning activities.	Review existing issues

	Calibrate system using actual peak day pressures
	Model base system to identify problem areas
	Model improvements for effect on system
	Model various scenarios as needed
	Identify improvements needed to system
	Capital planning (5 year minimum, 10-20 year preferred)
Planning model calibration/adjustments to actual system conditions.	5% or less
Operations staff involved in system planning and modeling activities?	Yes
Planning integrated to capital planning program for system improvements.	Within same planning year
Technology used in planning and modeling, how data is managed.	Synergi, GasWorks or similar simulation programs
Describe modeling scenarios used.	Design Day (most recent “worse case”)
	1 in 10 year, 1 in 30-year, multi-day event scenario

5.2 Each GDC shall develop and maintain a comprehensive prioritization program for analyzing the Reliability performance of its Natural Gas Distribution System during the course of each year, which shall include methods to measure and improve worst performing areas of the gas distribution system. Areas of prioritization may include replacement of aging infrastructure (cast iron, bare steel, aldyla plastic) and should tie into system planning and modeling program efforts. Natural Gas Distribution System areas are to be determined by the GDC.

6.0 Infrastructure, Safety, and Reliability Plan

6.1 Each GDC shall submit annually a proposed rolling 5-year Infrastructure, Safety, and Reliability Plan ("ISR") identifying proposed capital spending necessary to maintain the Reliability and quality of its Natural Gas Distribution Services. The proposed ISR shall be submitted no later than April 30, 2021 or 90 days following the effective date of this regulation, whichever is later, and no later than April 30th every year thereafter. The initial report shall address 2021, and subsequent reports will address the current year in which it is submitted and four subsequent years. The proposed ISR shall be structured under the following major spending categories:

6.1.1 Mandatory

6.1.1.1 New business - Customer requirements

6.1.1.2 Facility relocations

6.1.1.3 Required Statutory and Regulatory Requirements

6.1.1.4 Reliability - emergency failures/system improvements

6.1.1.5 Infrastructure Replacement Programs

6.1.2 Non-Mandatory

6.1.2.1 Supply/Capacity/Load/System Pressure

6.1.2.2 Asset Condition

6.1.2.3 Other Reliability (LNG, regulator station upgrades)

6.2 Mandatory spending shall include investments required to comply with customer requests, facility relocations, statutory and regulatory requirements, to repair failed equipment and for infrastructure replacement programs. The proposed budgets may be for a combination of discrete projects and projects that are funded but whose specific scope has not yet been defined ("blanket projects").

6.3 Non-Mandatory spending shall include projects, programs, or other investments necessary to maintain or improve Natural Gas Distribution Services that are not included in the mandatory spending category. Projects or groups of Related Projects shall be supported with project authorization documents, including detailed cost estimates. Infrastructure replacement and Reliability-based programs shall be supported by guidelines or program documents. The proposed budgets may be for a combination of discrete projects and blanket projects.

6.4 To support each proposed annual budget, the proposed ISR shall describe:

6.4.1 How the GDC developed the spending plan and levels;

6.4.2 The justification, scope, system planning and modeling outputs; and

6.4.3 Estimated cost for each planned project of $1,000,000 or more.

6.5 The proposed ISR shall include the GDC's estimated cost of plant in service and cost of removal for each year of the five-year term.

7.0 Review and Acknowledgement

7.1 Each ISR ("Plan") shall be submitted to the Staff and the DPA. Within the first 90 days following submission of each Plan, the GDC, Staff, and the DPA shall cooperate in good faith and schedule, if necessary, at least two sessions to meet and confer on the proposed Plan and discuss any proposed modifications.

7.2 No later than 120 days following the GDC's submission of each Plan to Staff and the DPA, the GDC shall file the proposed Plan with the Commission.

7.3 Staff and the DPA may submit comments on the Plan to the Commission by filing those comments within ten days of the GDC's filing of its proposed Plan.

7.4 The GDC has the right to file reply comments to Staff and the DPA comments to the Commission within ten days of their filings to the proposed Plan.

7.5 The Commission shall acknowledge that the Plan and any associated comments have been filed and that the Plan is consistent with the requirements of this regulation. Commission acknowledgement shall not constitute Commission pre-approval of any proposed capital spending necessary to maintain the Reliability and quality of the GDC's distribution services.

7.6 Any party may challenge the GDC's attempt to recover the amounts spent when the GDC seeks to include those amounts in rates.

7.7 The GDC's obligation to maintain the Reliability and quality of its Natural Gas Distribution System may necessitate executing on the Plan prior to the PSC's acknowledgement. In executing the ISR Plan, the circumstances encountered during the year may require reasonable deviations from the filed ISR Plan.

8.0 Annual Reports

8.1 Reliability Performance

8.1.1 By April 30 of each year, each GDC shall file with the Commission an annual Reliability Performance Report ("RPR") providing an overall assessment of the state of system Reliability in the GDC's service territory for the previous calendar year activities. The RPR shall include an assessment of the results/effectiveness of Reliability objectives, planned actions, projects, and programs implemented to achieve the Acceptable Reliability Level. The RPR shall include the GDC's actual year-end performance measure results.

8.1.2 The RPR shall include the GDC's Delivery facilities' year-end performance measures as follows:

8.1.2.1 AOR and AOD measures:

8.1.2.1.1 AOR and AOD measured by Planned and Unplanned Outages for the current year and three-year average reflecting Delaware performance, classified by distribution systems as identified in subsection 4.4. and in total, as compared to the Benchmarks established in subsection 4.2.

8.1.2.1.2 AOR and AOD measured by Planned, Unplanned Outages and in total for the current and previous five (5) years compared to Benchmarks.

8.1.3 The RPR shall identify distribution systems that are identified by the GDC as having the poorest Reliability according to the criteria established in subsection 4.4.

8.1.3.1 Current and previous five (5) year summary level Outage data shall include:

8.1.3.1.1 Number of Outages by Outage type (Planned and Unplanned).

8.1.3.1.2 Number of Outages by Outage cause.

8.1.3.1.3 Total number of customers at year end.

8.1.3.1.4 Total number of customers that experienced an Outage.

8.1.3.1.5 Total customer minutes of Outage time by Outage type.

8.1.3.1.6 Total customer minutes of Outage time by Outage cause.

8.1.3.2 The GDC shall indicate any planned Corrective Actions to improve system performance and target dates for completion or explain why no action is required.

8.1.4 The RPR shall include a summary of each Major Reliability Event for which data was excluded, and an assessment of the measurable impact on reported performance measures.

8.1.5 In the event that an GDC's Reliability performance measure does not meet the performance measures established in subsection 4.2, the RPR shall include a description of system issues impacting Reliability and all Corrective Actions that are planned by the GDC; the estimated cost of Corrective Actions; and the target dates by which the Corrective Actions shall be completed. If no Corrective Actions are planned, an explanation shall be provided.

8.2 Infrastructure, Safety, and Reliability Plan Annual Report

8.2.1 By April 30th of each year, starting April 30, 2021, each GDC shall submit an ISR annual report simultaneous with ISR plan submission discussed in Section 6.0 for the previous year, which shall include:

8.2.1.1 Overall progress.

8.2.1.2 Budget to actual variance for each spending category, and discussion of the drivers of the variance. An explanation of the variance for any program or project exceeding $1,000,000 that was completed in the reporting year and exceeds +/- 10% of the proposed budget.

8.2.1.3 Comparison of actual versus planned project implementation and discussion of deviations, including delays and accelerated work; and an explanation for inclusion of any program, project, or group of Related Projects with a total cost estimate exceeding $1,000,000 that were not previously included in an ISR.

8.2.1.4 Comparison of infrastructure replacement program activities to the ISR, and discussion of deviations and drivers.

9.0 Major Reliability Event Report

9.1 Each GDC shall notify the Commission of Major Reliability Events as soon as practical, but not more than 36 hours after the onset of a Major Reliability Event. Initial notification is required when more than 1000 of a GDC's customers experience a Sustained Outage during a 24-hour period.

9.2 Each GDC is expected to restore service to customers as quickly and safely as permitted by Major Reliability Event conditions. The GDC's restoration effort may be subject to review. The Commission may require subsequent Corrective Actions and impose penalties as permitted by Section 10.0 or other applicable Delaware law.

9.3 Within 15 business days after the end of a Major Reliability Event, the GDC shall submit a written report to the Commission, which shall include the following:

9.3.1 The date and time when the GDC's Major Reliability Event control center opened and closed;

9.3.2 The total number of customers out-of-service over the course of the Major Reliability Event in six-hour increments;

9.3.3 The date and time when 75%, 95% and 100% of customers affected by a Major Reliability Event were Restored;

9.3.4 The total number of service orders completed, by order type;

9.3.5 The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor responses to the requests for assistance; and

9.3.6 A timeline profile in six-hour increments of the number of company crews, mutual aid crews, and non-company contractor crews working on restoration activities during the duration of the Major Reliability Event.

10.0 Penalties and Other Remedies

10.1 Any GDCs subject to Commission regulation who violate any of the requirements of this regulation is subject to penalties and other remedial actions in accordance with this section and other applicable Delaware law.

10.2 No penalty shall be assessed except after a public hearing at which the GDC, Staff, the DPA, or any other affected person may present evidence. The Commission shall be responsible for assessing any penalty under this section, consistent with Delaware law.

10.3 A GDC shall be considered in violation of the AOR or AOD performance Benchmark standard when its actual results exceed the Benchmark standards as defined in subsection 4.2. However, no GDC shall be penalized before the Commission has established Benchmark standards in accordance with the procedure described in subsection 4.2.

10.4 Penalty assessments are payable as provided by Delaware statute.

10.5 Nothing in this section relieves any GDC from penalties that may be assessed due to non-compliance with any requirement set forth under any other federal, state or local regulation, statute, ordinance or order.

11.0 Reporting Specifications and Implementation

11.1 Each GDC must maintain sufficient records to permit a review and confirmation of material contained in all required planning documents and reports. Reports shall be submitted electronically via Delafile to the PSC Secretary, with certification of authenticity by an officer of the corporation.

11.2 Subject to and without waiving the requirements of 29 **Del.C.** Ch. 100 (the "Freedom of Information Act" or "FOIA"), GDCs may request information required to be provided by this regulation to be classified as confidential, proprietary or privileged material. The GDC must attest that such information is not subject to inspection by the public or other parties without execution of an appropriate proprietary agreement. Each GDC requesting such treatment of information is also obligated to file one (1) additional electronic and paper copy of the information, excluding the confidential or proprietary information. The Commission, in accordance with the FOIA and 26 **DE Admin. Code** 1001, will treat such information as "confidential, not for public release" upon receipt of a properly filed request. The Commission, designated Presiding Officer, or Hearing Examiner shall resolve any dispute over the confidential treatment of information in accordance with the FOIA and 26 **DE Admin. Code** 1001.

24 DE Reg. 405 (10/01/20)