Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

July 31, 2013

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
ELECTRIC SERVICE QUALITY REPORT
DOCKET NO. E002/M-13-255

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the July 1, 2013 Comments of the Minnesota Department of Commerce – Division of Energy Resources and the June 28, 2013 Comments of the City of Minneapolis in the above-referenced docket.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list.

Please contact Rebecca Eilers at 612-330-5570 or rebecca.d.eilers@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE & FILINGS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION'S, ANNUAL SAFETY, RELIABILITY, AND SERVICE QUALITY REPORT FOR 2012; AND PETITION FOR APPROVAL OF RELIABILITY GOALS FOR 2013

DOCKET NO. E002/M-13-255

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the July 1, 2013 Comments of the Minnesota Department of Commerce – Division of Energy Resources and the June 28, 2013 Comments from the City of Minneapolis on our Annual Safety, Reliability, and Service Quality Report for 2013; and Petition for Approval Reliability Goals for 2013.

We appreciate the review of our Petition by parties and the Department's recommendation that the Commission accept our Report and our proposed 2013 reliability goals. We provide our Reply below.

REPLY

A. Safety Report

The Department requested we provide information about actions taken to prevent incidents similar to the incident cited in our report which resulted in injuries requiring medical attention. The reported sparking incident was addressed by a troubleman who arrived on the scene when the injury was reported. At that time, there was no further evidence of sparking. To prevent similar incidents, we have a longstanding program in place where a portion of our distribution lines are checked for hot spots once a year using infrared scanning. These infrared scans identify temperatures above ambient which reveal potential loose connections or failed devices. When we find a failure, we replace that connection or device. Given the size of our system, we are able to scan only a portion each year, but if a member of the public or one of our crew members sees a situation that does not look safe, we react immediately and stop work to investigate.

B. Reliability

1. CAIDI

The Department requested we provide a discussion on our CAIDI performance in all four work centers. Specifically, they asked us to explain why several small weather-related events would lead to a missed CAIDI goal given that the data is weather-normalized. The Department further requested we explain what factors could be contributing to our declining CAIDI performance and what we could do to improve our response going forward.

We note first that the data is not "weather-normalized" but instead "storm-normalized." The data has been neutralized to eliminate the outages from major storms. Therefore, the data is only normalized to an extent and those days that nearly qualify for a storm day are included in our data. We note that in 2012 we did not have many storm days – but we had a lot of "near misses" – so we had a lot of outages that impacted a significant number of customers that were included in our final results. As noted in our April 1, 2013 report in this docket, we had several storms, high winds and lightening in 2012 that caused widespread customer outages, but these events fell below the level of qualifying for a storm day. In fact, we had just 14 storm days across all work centers in 2012 compared to 27 storm days in 2011. As our current standards in this docket are based on a rolling five-year average, even one extensive outage that does not qualify as a storm day can quickly worsen our results.

As for the factors that could be contributing to our CAIDI performance, we note that a significant influence on CAIDI performance is the number of outages at the feeder level. This is due to the fact that (1) feeder level outages affect many customers so they have a material impact on the metrics, and (2) because we can usually restore service to customers impacted by these events through a switching procedure, they represent our shortest outages by a significant margin.

Therefore, our increased use of Intelliteam switches, which reduces the impact of feeder level outages, is starting to have an impact on our CAIDI performance. Our Intelliteam switches isolate and automatically redirect power flow during a major outage. Thus instead of a feeder breaker outage affecting thousands of people when the breaker goes out, the fault is isolated, the feeder is automatically healed and a much smaller number of customers are left without power. While this automatic process reduces the number of overall outages (and therefore improves our SAIDI performance) it also increases our CAIDI, because the CAIDI measure actually improves when many customers go off line for a short period of time. The bigger events that the Intelliteam switches are now reducing had previously diluted the effects of the smaller, shorter outages.

Because feeder level outages have such a material impact on our overall reliability statistics, the better our feeder level reliability, the better our SAIDI and SAIFI performance but the worse our CAIDI performance. So while the use of our Intelliteam switches is preventing mass extended outages on the system, it has now increased the focus on the restoration time of the smaller outages that affect fewer customers but that require more complex restoration work.

With respect to how we are going to improve our CAIDI performance going forward, we note that we have taken the following actions to date:

- *Increased Feeder Patrol*- We identified our 10 worst performing feeders (based on the number of outages) and increased our troublemens' patrol of those specific feeders. The troublemen check the overall feeder including the insulators, wire condition, transformers, switches, and arrestors to see if anything needs service to prevent outages.
- *More Frequent Testing*- We are testing lightening arrestors (devices that protect our system from the damaging effects of lightening) on a proactive basis. We have a full-time employee fully dedicated to testing lightening arrestors throughout the system.
- *Additional Animal Protection*- We just began installing a new piece of protection equipment called Animal Guards on transformers that have the largest number of outages caused by animal contact. This device is installed on the primary bushing of a transformer and protects the equipment so the animal cannot make contact with it and cause a potential outage.
- *Proactive Staffing*- We are adjusting our staffing levels more proactively based on weather forecasts. This helps us be more prepared to react and respond to potential outages.

2. Northwest Work Center

In their Comments, the Department requested a discussion around our Northwest work center, as well as specific actions we are taking to improve performance there.

First, we provide a general discussion around our Northwest work center. Our Northwest work center covers a wide geographic and mostly rural area. As with most rural areas, much of our Northwest region (except the city of St. Cloud) is not equipped with switching capability; therefore, when a feeder is out, there is no way to switch it to a different feeder section and the customers remain out of service while we fix the issue. This is different than metro areas where the system is looped and we can more easily isolate the affected customers and restore the other customers while we work on the impacted portion of the feeder.

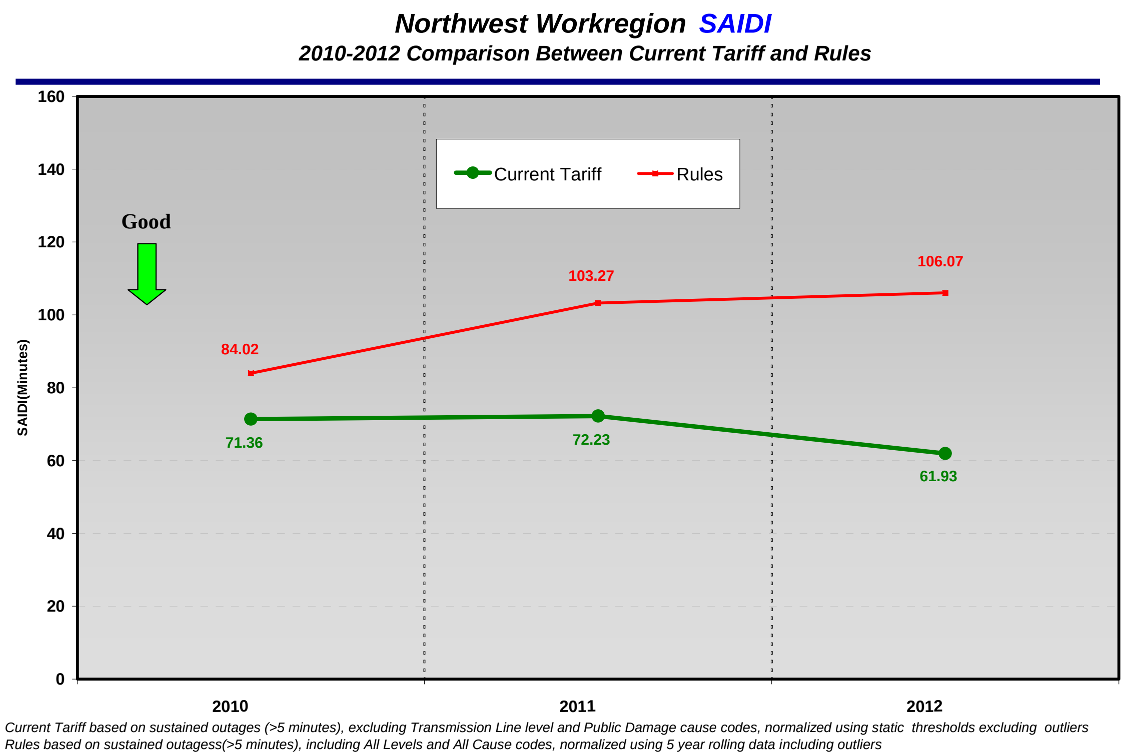
Another unique aspect to our Northwest work center is that despite its wide territory, it has a relatively small customer population. These two characteristics have an impact on our overall work center metrics. For instance, if our Northwest work center had an event that caused 100,000 customers to have their service interrupted, that would be 88 percent of our Northwest customers and would cause a large impact on all our performance metrics for that region. If that same event were to happen in our Metro West work center, that would only be 17 percent of customers, not quite the severe impact on the overall statistics. Therefore, distribution events affect our rural work centers' statistics more greatly which can cause more variability year to year.

Lastly, the make-up of the rural Northwest territory can impact the drive time it takes for our responders to arrive at the service location. This region can also be more severely impacted by wind and snow than our typical metro locations. We do require our responders to live within 20 miles of the service center and, among our service centers, our Northwest region has one of the fastest response times for the first responders to accept an outage call. However, because of some of the significant damage we experience, as well as the large service territory overall, the total restoration time quickly adds up.

In analyzing our Northwest work center performance, we also look at the results under our Quality of Service Plan (QSP) Tariff, which uses a different reporting methodology.[1] Below we provide graphs showing our Northwest region's SAIDI, SAIFI, and CAIDI performance over the last three years comparing the current QSP Tariff and the Minnesota Rules based reporting methods. We note that while these

[1] The QSP Tariff can be found in our Minnesota Electric and Gas Rate Books MPUC. No. 2 Section 6, Sheets 7.1 through 7.10.

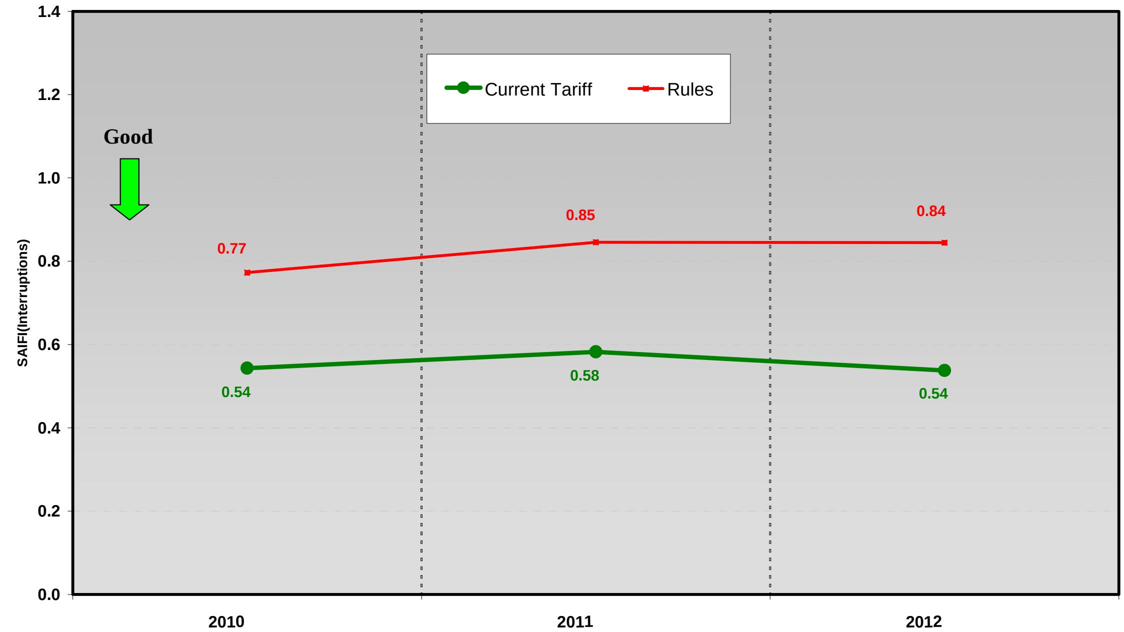
two reporting calculations are different, this is the exact same customer experience – just a different way to view it.[2] As can be seen below, the QSP Tariff calculations have an opposing trend from the MN Rules reporting methodology and in fact, it looks like we are maintaining or even improving our performance.



[2] The current Tariff Method has a static storm day threshold based on first removing extreme outlier days. This method excludes Transmission Line Levels and Public Damage cause codes. The MN Rules Method has a moving storm day threshold based on the previous five years of data. It includes all days, including extreme outliers, and it includes all Levels and all cause codes.

Northwest Workregion SAIFI

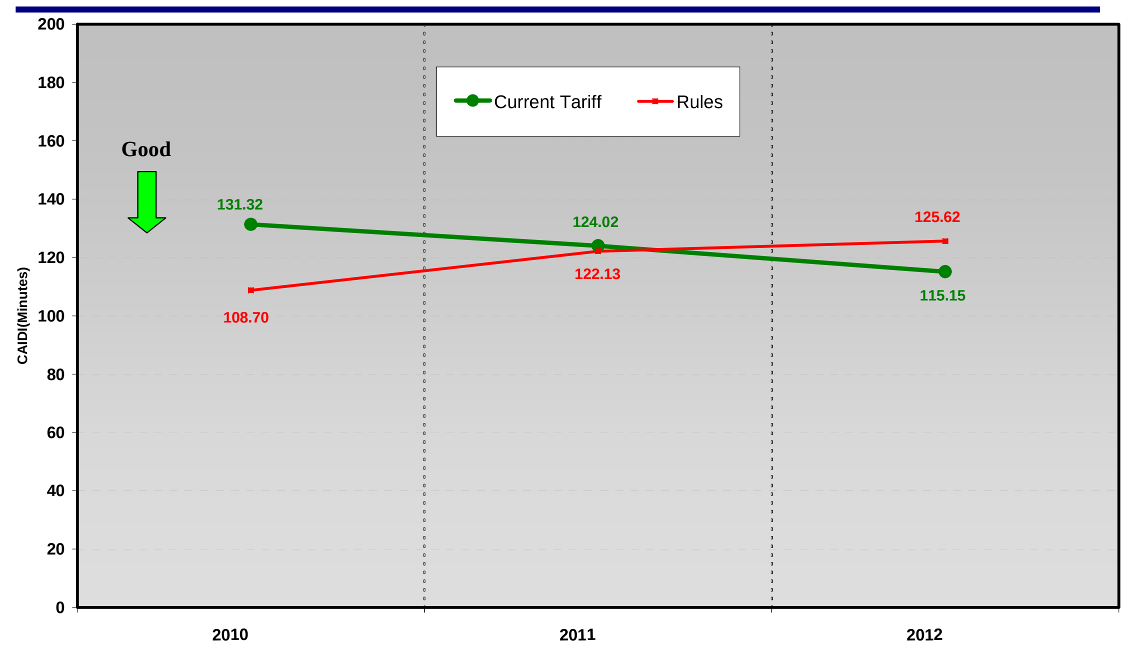
2010-2012 Comparison Between Current Tariff and Rules



Current Tariff based on sustained outages (>5 minutes), excluding Transmission Line level and Public Damage cause codes, normalized using static thresholds excluding outliers
Rules based on sustained outagess(>5 minutes), including All Levels and All Cause codes, normalized using 5 year rolling data including outliers

Northwest Workregion CAIDI

2010-2012 Comparison Between Current Tariff and Rules



Current Tariff based on sustained outages (>5 minutes), excluding Transmission Line level and Public Damage cause codes, normalized using static thresholds excluding outliers
Rules based on sustained outagess(>5 minutes), including All Levels and All Cause codes, normalized using 5 year rolling data including outliers

Under the Minnesota Rules calculation method, we removed eight storm days in the Northwest work center in both 2010 and 2011. However, in 2012, there was only *one* storm day that was excluded because there was a significant increase in the storm day threshold level. Since 2004 the storm day threshold (or number of daily outages required to qualify as a storm day) for the Northwest region has been between 25-27 outages. In 2012, that threshold jumped up to 37 events per day. This was due to a large increase in the standard deviation of events per day used in the threshold calculation. We typically have one or two days a year in the Northwest region with 100 or more events; however, in 2011 we had four, with one of them being close to 300 events.

Had we been at recent outage threshold levels (between 25-27 outages) in 2012, we would have had many more storm days, as opposed to the one storm day we actually had. Below we provide three illustrations for our 2012 goals using storm day thresholds that would have been in line with previous years' thresholds:

- If the threshold had been at 26 or 27 outages, we would have had four storm days and we would have been on target for all three metrics with the following results:
  - 85.05 SAIDI/0.77 SAIFI/110.19 CAIDI
- If the storm day thresholds had been at 25 outages, we would have had seven storm days and again, we would have met the target for all three metrics with the following results:
  - 78.73 SAIDI/0.74 SAIFI/105.75 CAIDI
- Even if the threshold had gone up a reasonable amount to 28-31 outages, we still would have had three storm days and still been on target for SAIDI and SAIFI and been only a little over two minutes off on CAIDI, with the below results:
  - 90.69 SAIDI/0.79 SAIFI/114.14 CAIDI

The above examples are meant to demonstrate the impact that one bad storm year (such as 2011) with more than average extreme outliers has such an extreme impact on results under the Minnesota Rules methodology. Conversely, it can also help when there is a good year, like 2009. In both cases, if all else is normal, the good or bad days and years will stick with the metrics in the threshold calculations for five years.

As discussed above, analysis of our reliability performance really varies depending on what calculation methodology is used. However, at the end of the day, the customers receive the same experience regardless of the calculations we use to report our performance. Our strong performance, when viewed under the QSP Tariff methodology, the tightening storm day thresholds, and the fact that we have often narrowly missed the goals leads us to believe we do not have performance issues in the Northwest work center. However, providing reliable service is important to us, and we are always looking for ways we can improve. Below are some of the steps we have taken in the past few years to improve our performance, reduce outages, or make our system more robust in the Northwest work center:

- We implemented a mandate that limits our first responders' time off and ensures no more than 25-30 percent of the work force is off at one time;
- We have installed bird diverters on distribution lines to cut down or decrease momentary outages caused by birds flying into the power lines;
- We have replaced approximately 600 poles over the past three years;
- We have hung fault indicators on overhead lines to help us identify more efficiently the cause of the outage; and
- We have conducted infrared surveys throughout the Northwest region's distribution system to find hot spot conditions and try to correct problems before they cause an outage.

3. Worst Performing Feeders

The Department requested a discussion regarding our two worst-performing feeders, one in our Metro East work center and one in our Southeast work center, and the likelihood of related issues recurring in the future.

The feeder in our Metro East work center identified outages in 2010 and 2012 caused by a connector failure. As noted in our previous reports, in 2010 we replaced connections and splices on this feeder, and in 2012 we performed the design work and some construction work to rebuild the overhead feeder to eliminate splices. In 2013, we completed the construction work to rebuild most of the overhead mainline feeder. The project was significant in design, size and scope, and we have spent more than $200,000 to rebuild most of the overhead portions and eliminate all overhead splices.

In addition, we also have planned work in 2013 and 2014 on two other feeders that will reconfigure the load. These upcoming efforts will reduce the load and exposure on the feeder in question in our Metro East work center. We believe all of these actions will address the issues we have experienced with this feeder, and we expect improved reliability from this feeder going forward.

The other feeder in question is located in our Southeast work center and has had issues with vegetation and trees in the past few years.

In our 2012 report we stated that we had re-routed the affected feeder to allow better access. As part of our re-routing efforts, we re-built a portion of this feeder entirely. In addition, we also relocated the feeder to allow our personnel easier access for patrolling as well as maintenance and restoration. We expect our efforts will not only reduce the likelihood of outages but also decrease the amount of time required to restore service after an outage.

However, while we have made efforts to improve this feeder's reliability, there was one extended outage on this feeder in 2013 to date. The outage was on May 2, 2013, a storm day, and it was due to a tree from outside the maintenance corridor that was blown into the line. Since our FPIP selection criteria are based on all days, including storm days, we expect this feeder may show up on the FPIP list again this year as a result of this extended outage.

4. Reliability Indices

The Department requested the Company discuss whether we considered any additional factors on which to base our reliability indices in 2013.

The Company notes that yes, we did consider other factors and methodologies, such as means, medians, and standard deviations, but after comparing these calculations to our historic performance we ultimately determined it would be useful to maintain our comparison baseline five-year rolling average methodology that has been approved by the Commission since the Minnesota Rules, Chapter 7826 first went into effect into 2003.

However, we are open to guidance and suggestions for changing the calculation methodology if that is what the Commission prefers.

C. Meters

i. Number of Meters Installed

The Department requested clarification of the number of meters installed and read by the Company during 2012.

In our initial filing, we reported the Total Meters Installed in Minnesota as 2,258,245. This is the first year we have reported this data, and as we examined the data further, we discovered that our initial data pull had not been verified to the extent that it should have been. There was an error in the query made of the source system, so it included all of the meters installed in Minnesota, even if the meter had been removed from the field in years prior to December 31, 2012. The actual number of Total Meters Installed in Minnesota as of December 31, 2012 was 1,700,301.

Table 1 below shows the total number of meters installed in Minnesota by month for 2012 as requested by the Department in Docket No. G002/M-12-440. We will provide this data going forward in our electric service quality reports.

Table 1: Meters Installed by Month in 2012

	Residential	Commercial	Industrial	Other	Total
JANUARY	1,522,318	156,036	9,905	5,035	1,693,294
FEBRUARY	1,522,546	156,045	9,897	5,026	1,693,514
MARCH	1,523,032	156,052	9,893	5,019	1,693,996
APRIL	1,523,519	156,054	9,886	5,020	1,694,479
MAY	1,523,915	156,141	9,878	5,017	1,694,951
JUNE	1,524,469	156,202	9,867	5,009	1,695,547
JULY	1,525,220	156,302	9,860	4,998	1,696,380
AUGUST	1,525,830	156,382	9,852	5,002	1,697,066
SEPTEMBER	1,526,552	156,506	9,832	5,046	1,697,936
OCTOBER	1,527,462	156,668	9,819	5,046	1,698,995
NOVEMBER	1,528,113	156,838	9,805	5,054	1,699,810
DECEMBER	1,528,440	157,003	9,803	5,055	1,700,301

ii. Calculation of Percent of Meters Read

The Department indicates in Comments that the percentage of meters read by the utility should be calculated by dividing the number of meters read by the utility by the number of all meters installed. Prior to this reporting year, however, we were not required to provide the total number of installed meters, so we calculated the percentage of meters read by dividing the number of Company reads by the total number of meters read. Now that the report includes both the number of meters installed and the number of meters read by the Company, we agree that the appropriate calculation method for percentage of meters read is to divide the number of meters read by the Company by the number of all meters installed, as follows:

$$\text{Percent Read By Utility}_{\text{Jan}} = \text{Total Meter Reads}_{\text{Jan}} / \text{Total Meters Installed}_{\text{Jan}}$$

However, the numbers presented in Table A of Attachment F of our initial filing included *all* meters read by the utility, including any multiple reads of a meter within the same month. If these counts are used in the above formula, the percent of meters read by the Company appears to exceed 100 percent in some months. To better calculate the percent of meters read, Table 2 below excludes multiple reads of the same meter during each month.

Table 2: Meter Read Totals by Month – Excluding Multiple Reads Per Meter

	Residential	Commercial	Industrial	Other	Total
JANUARY	1,505,771	153,724	9,647	4,648	1,673,790
FEBRUARY	1,507,831	153,889	9,605	4,639	1,675,964
MARCH	1,509,912	152,374	9,536	4,565	1,676,387
APRIL	1,510,608	153,135	9,427	4,630	1,677,800
MAY	1,507,721	154,438	9,620	4,708	1,676,487
JUNE	1,444,374	150,523	9,669	4,567	1,609,133
JULY	1,507,362	154,240	9,599	4,646	1,675,847
AUGUST	1,513,016	154,427	9,493	4,640	1,681,576
SEPTEMBER	1,448,147	151,065	9,419	4,594	1,613,225
OCTOBER	1,519,057	155,415	9,570	4,644	1,688,686
NOVEMBER	1,375,652	141,258	8,937	4,303	1,530,150
DECEMBER	1,390,135	147,199	9,251	4,421	1,551,006

A meter may be read more than once in any given period for a variety of reasons. For example, if a residence needs to have the meter replaced, the old meter is read prior to being removed, and the new meter will be read later in the month for the billing cycle. Both of these reads would have been counted in our original Table A of Attachment F in our initial filing.

Table 3 below shows the updated values for total meters read by the Company divided by the total number of meters installed to calculate our updated percentage read by the Company.

Table 3: Percent of Meters Read by Company by Month

	Total Installed	Total Read by Company	Percent Read by Company
JANUARY	1,693,294	1,673,790	98.85%
FEBRUARY	1,693,514	1,675,964	98.96%
MARCH	1,693,996	1,676,387	98.96%
APRIL	1,694,479	1,677,800	99.02%
MAY	1,694,951	1,676,487	98.91%
JUNE	1,695,547	1,609,133	94.90%
JULY	1,696,380	1,675,847	98.79%
AUGUST	1,697,066	1,681,576	99.09%
SEPTEMBER	1,697,936	1,613,225	95.01%
OCTOBER	1,698,995	1,688,686	99.39%
NOVEMBER	1,699,810	1,530,150	90.02%
DECEMBER	1,700,301	1,551,006	91.22%

Using our updated counts, the percent of meters read by the Company is in compliance for each month in 2012. Now that we have we have refined our meter reading data collection with the new reporting parameters, we will exclude multiple reads on a single meter in future reports. We apologize for any confusion and thank the Department for bringing the discrepancy to our attention.

D. Reply to the City of Minneapolis Comments

We thank the City of Minneapolis for their letter in this docket and note that we have begun working with the city to determine how we can meet their requests and plan to continue meeting with them to provide them meaningful reliability data and information.

CONCLUSION

We appreciate parties' review of our Report and are hopeful the additional information we provided in these Reply Comments meets the Department's requests for further clarification and information. We respectfully request that the Commission approve our Annual Safety, Reliability, and Service Quality Report for 2012; and Petition for Approval of Reliability Goals for 2013.

Dated: July 31, 2013

Northern States Power Company

Respectfully submitted by:

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE & FILINGS

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

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

xx electronic filing

Docket No. E002/M-13-255

Dated this 31st day of July 2013

/s/

____
SaGonna Thompson

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