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August 1, 2014

OTTER TAIL POWER COMPANY

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Otter Tail Power Company's 2014-2028 Resource Plan
Docket No. E017/RP-13-961
Reply Comments

Dear Dr. Haar:

Otter Tail Power Company ("Otter Tail") respectfully submits these Reply Comments to the Minnesota Public Utilities Commission ("Commission") in the above-referenced docket.

Otter Tail has electronically filed this document with the Commission and is serving a copy on all persons on the official service list for this docket. A Certificate of Service is also enclosed.

If you have any questions regarding this filing, please contact me at bhdraxten@otpco.com or (218) 739-8417.

Sincerely,

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

wao
Enclosures
By electronic filing
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2014-2028 Integrated Resource Plan

Docket No. E017/RP-13-961

OTTER TAIL POWER COMPANY REPLY COMMENTS

I. INTRODUCTION

Otter Tail Power Company ("Otter Tail" or "Company") submits these Reply Comments in response to the May 2, 2014 Comments of the Minnesota Department of Commerce, Division of Energy Resources ("Department") and the Minnesota Center for Environmental Advocacy, *et al*. ("MCEA"), filed in the above-captioned docket.

As defined in Minn. Rules 7843.0100, subp. 9, "Resource Plan" means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those needs. These resource options include using, modifying, and constructing utility plant and equipment; buying power generated by other entities; controlling customer loads; and implementing customer energy conservation.
Minn. Rules 7843.0500, subp. 3, lists the factors to be considered when the Minnesota Public Utilities Commission ("MPUC") issues its findings of facts and conclusions. Resource options and Resource Plans must be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service.
B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints.
C. Minimize adverse socioeconomic and environmental effects.
D. Enhance the utility's ability to respond to changes in financial, social, and technological factors affecting its operations.
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Otter Tail Power Company has submitted a Resource Plan that maintains adequate and reliable electric service while keeping customer's electric rates as low as possible. Otter Tail's plan also minimizes both the socioeconomic and environmental impacts while at the same time maintains flexibility to respond to changing financial, social and technological factors.

Otter Tail disagrees with the Department's proposed modifications to its plan. Specifically, the Department incorrectly recommends Otter Tail should build resources in excess of those required to meet its MISO resource adequacy requirements at a cost of approximately $112 million, based upon an apparent misunderstanding of how the MISO resource adequacy construct works.

The Department also misunderstands how Otter Tail has modeled the energy market in its Strategist modeling, and incorrectly refers to Otter Tail's approach to reflecting market availability as "market reliance." As is demonstrated in the Reply Comments, however, Otter Tail's approach to market availability doesn't expose it to the wholesale market. The Department's approach, on the other hand, would prevent Otter Tail from using the market when it presents opportunity for reducing energy costs below the fuel costs of its units.

Otter Tail also disagrees with the Department's recommendation that it should use a 1.7 percent Conservation Improvement Program goal in its planning. While such an increase might be aspirational, it is not reasonable to use for planning based on historical CIP achievement or any other statutory or regulatory mandate. Use of the 1.5 percent CIP goal, which is both required by statute and approved in the Company's 2013 CIP triennial filing, is the appropriate level of energy efficiency to be included in the resource plan.

These Reply Comments also address the solar Energy Standard, the Greenhouse Gas Emissions Goal, and several forecasting issues. They also provide information requested by the Department, and they explain mistakes made by MCEA in its criticisms of Otter Tail's load forecasting.

II. SHOULD OTTER TAIL ADD RESOURCES IN EXCESS OF THOSE REQUIRED TO MEET MISO RESOURCE ADEQUACY?

The single largest issue in the current Resource Plan discussion is whether Otter Tail should build resources in excess of those required to meet its MISO resource adequacy requirements at a cost of approximately $112 million. Otter Tail disagrees with the Department on this point and recommends that the Commission should not require the addition of these excess investments. Doing so would materially increase Otter Tail's customer rates and would neither improve reliability nor increase Otter Tail's ability to meet its resource adequacy requirements (which are being met without such excess resources).

Otter Tail, like all other MISO utilities, has used the MISO resource adequacy construct and the MISO Coincident Peak method in particular to determine the peak demand included in its resource plan. Otter Tail realizes very significant benefits for customers under the MISO construct. Under the construct, MISO sets resource adequacy requirements for its Load Serving Entity members based upon the point in time when the aggregate peak energy usage occurs within the MISO footprint (the MISO coincident peak). The construct's use of the MISO coincident peak for setting resource adequacy requirements is very beneficial to Otter Tail's customers and it is not new to the construct. The following sections of these Comments provide background on the construct and an explanation of how the construct benefits Otter Tail's customers.

A. Background on MISO Resource Adequacy Construct

Achieving reliability in the bulk electric system requires, among other things, that the amount of resources exceeds customer demand by an adequate margin (the margin is referred to as the Planning Reserve Margin ("PRM")). The overall demand plus the PRM is referred to as the Planning Reserve Margin Requirement ("PRMR"). The PRM necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis. In the real-time operational environment, only resources dedicated to meet demand have an obligation to be available to meet real-time customer demand and contingencies. Therefore, PRMR must be sufficient to cover:

- generator forced outage rates of capacity resources;
- generator planned outages;
- expected performance of Load Modifying Resources and Energy Efficiency Resources;
- load forecast uncertainty; and
- the transmission systems import and export capability with external systems.[2]

[2] MISO FERC Electric Tariff, Module E1, Version Dated November 19, 2013, Section 68A.2

The development of MISO's resource adequacy construct has occurred over two general phases demarked by the naming convention for the Module of MISO's Tariff in which the construct is described: "Module E" and "Module E1."

Prior to joining MISO and until MISO first established its resource adequacy construct, Otter Tail was a member of the Mid-Continent Area Power Pool ("MAPP"), which had authority over Resource Adequacy. MAPP was formed in the mid-1960s. Although its role in the electric industry was multifaceted, MAPP functioned as a reserve sharing planning group, responsible for Resource Adequacy.

On March 31, 2004 MISO submitted its first Open Access Transmission and Energy Markets Tariff which included interim provisions for Resource Adequacy ("Module E").[3] The tariff filing was approved by the Federal Energy Regulatory Commission ("FERC") on August 6, 2004.[4] Otter Tail was a transmission owning member of MISO at that time and was subject to the interim Resource Adequacy requirements.

On December 28, 2007, MISO submitted proposed revisions to its Open Access Transmission and Energy Markets Tariff to revise its interim Module E to comprehensively address long-term resource adequacy requirements.[5] That filing was approved by the FERC on March 26, 2008 and was effective for the MISO planning year starting June 1, 2009.[6]

Module E might at first appear to be a monthly non-coincident peak construct, but that is not the case. Under Module E, MISO Load Serving Entities ("LSE's") were required to plan resources to their monthly non-coincident peak load forecast plus a PRM. The monthly peak forecast was a 50/50 forecast, meaning that there is a 50 percent probability the forecast will be over, and a 50 percent probability the forecast will be under, the actual peak demand. While this calculation began with a non-coincident peak forecast from each LSE, the calculation also included an adjustment to reduce all forecasted peaks by a MISO-calculated "diversity factor" for the purpose of arriving at a resource adequacy requirement for each LSE's contribution to the MISO coincident peak. This diversity factor was necessary to recognize diversity among loads served by LSEs in the MISO footprint. Accounting for load diversity is necessary because all

[3] FERC Docket No. ER04-691-000, Midwest Independent System Operator, March 31, 2004
[4] FERC Docket No. ER04-691-000, Federal Energy Regulatory Commission, August 6, 2004
[5] FERC Docket No. ER08-394-000, Midwest Independent System Operator, December 28, 2007
[6] FERC Docket No. ER08-394-000, Federal Energy Regulatory Commission, Order on Resource Adequacy Proposal, March 26, 2008

LSEs' loads peak at different times. If an adjustment were not made, the aggregate non-coincident peak demands would inaccurately reflect a much higher aggregate demand.

The diversity in load occurs for a number of reasons. MISO covers a very large geographic area. Weather patterns that drive peak demand may occur in different geographic regions at different times. Each LSE has a different mix of customers which may drive peaks to occur at different times of the year or different times of the day. Not accounting for this diversity would create excess resource requirements and unnecessary costs. One limitation of the calculated diversity factor used under Module E was that it spread the benefits of MISO-wide diversity to all LSE's equally rather than in amounts that reflected each LSE's specific contribution to the diversity.

On July 20, 2011 MISO filed revisions to its tariff's resource adequacy construct provisions with FERC under docket ER11-4081-000.[7] FERC approved the revisions on June 11, 2012 and they became effective for the MISO planning year that began on June 1, 2013.[8] The resource adequacy construct resulting from the July 20, 2011 tariff revisions is known as "Module E1."

Module E1 arrives at each LSE's coincident peak demand requirements in a way that more accurately reflects each LSE's actual diversity in relation to the remaining MISO LSE's. In order to determine each LSE's requirements, each LSE provides annual peak demand forecasts coincident with the MISO region's peak (MISO's peak typically occurs during the summer months). Under Module E1, the forecast probability remains at 50 percent.[9] Module E1 had the effect of moving the diversity calculation from the PRM to the peak demand forecast. This approach results in a more equitable distribution of the diversity benefit. In its application to FERC for these Module E1 revisions, MISO explained that this change in the methodology would "account for load diversity in the individual demand forecasts provided by LSEs."[10] In its Order approving Module E1 FERC found that these forecasts "provide an accurate and reasonable basis for establishing peak demand requirements in the MISO regions." FERC also

[7] FERC Docket No. ER11-4081-000, Midwest Independent System Operator, July 20, 2011
[8] FERC Docket No. ER11-4081-000, Federal Energy Regulatory Commission, June 11, 2012
[9] MISO FERC Electric Tariff, Module E1, Version Dated November 19, 2013, Section 69A.1.1
[10] Docket No. ER08-394-000, Federal Energy Regulatory Commission, Order on Resource Adequacy Proposal, March 26, 2008, Page 69

found that “MISO’s proposed forecasting methodology has been used in other regions throughout the United States and is a well-accepted forecasting methodology.” [11]

B. How Otter Tail’s Resource Adequacy Requirements are Determined under MISO’s Tariff

Because Otter Tail’s peak is significantly diverse from MISO’s peak, it sees significant diversity benefits in its resource adequacy requirements calculation under Module E1. There are some obvious reasons for this diversity. For example, Otter Tail is a winter peaking utility and MISO is a summer peaking entity, therefore Otter Tail needs significantly fewer resources to meet its load requirements at the time of the MISO’s peak (in the summer) than it would to meet its load requirements on Otter Tail’s peak (in the winter).[12] MISO’s construct recognizes that when Otter Tail needs resources, there are many others in MISO that don’t need them; and when others need resources, Otter Tail does not. The financial benefits of this arrangement are realized possibly more significantly for Otter Tail than for many other MISO utilities due in part to its status as a winter peaking utility and in part due to Otter Tail’s geographic distance from MISO’s major load centers. It should be noted that Otter Tail’s load is less than 1 percent of MISO’s total load so is very unlikely to influence when MISO peaks.

Despite the noteworthy benefit conferred to Otter Tail customers from MISO’s recognition of the diversity benefit it brings to the MISO region, the Department recommends in its Comments that Otter Tail should either build or purchase new additional generating resources in order to meet its stand-alone peak demands, by ignoring the MISO tariff methodology and instead applying an Otter Tail-only non-coincident peak approach. This would, of course, result in the loss of the significant benefits derived from the diversity of resources described above. It would cost Otter Tail’s customers a tremendous amount—$112 million in NPVRR—and it would not increase reliability or help Otter Tail meet its resource adequacy requirements. One of the major benefits of MISO is the efficient use of capacity and energy resources within its footprint. Requiring Otter Tail to construct more resources than it would need prior to when they are needed does not allow customers to benefit from the Company’s membership in MISO.

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[11] Docket No. ER08-394-000, Federal Energy Regulatory Commission, Order on Resource Adequacy Proposal, March 26, 2008, Page 70

[12] There are numerous other more subtle factors that contribute the diversity Otter Tail brings to MISO, but this seasonality difference provides a very visible example that is useful for illustration.

C. Additional considerations on the issue of whether to require Otter Tail to build generating resources in excess of those needed to meet MISO resource adequacy requirements.

There are other practical considerations to consider on this issue. For example, if the intent of requiring the procurement of excess capacity as recommended by the Department is to add an additional layer of planning reserves beyond the reserves required under the MISO tariff and to specifically hold them back as designated for Otter Tail, it is not clear whether such a requirement would have that effect in practice. According to Module D, Section 64.1.1 of MISO's Tariff, the MISO Market Monitor's rules currently only allow MISO market participants to carry less than 50 MW of excess capacity. Exceeding this amount is considered physical withholding. Planning to Otter Tail's non-coincident peak for resource planning purposes and planning to the coincident peak for MISO resource adequacy purposes would create excess capacity for MISO resource adequacy purposes. If the excess was 50 MW or more, it would appear Otter Tail may be required by the above-cited market monitor rules to sell the excess quantities through either the bilateral market or MISO's annual capacity auction.

We note that this is not utility-specific nor a state-specific issue. Instead, this issue has region-wide implications. If the Department's recommendations were accepted, it would result in fundamental system planning differences in the region that would affect other MISO utilities, and especially those operating systems that serve areas of the region that go outside Minnesota. To the extent that the Commission desires further dialogue on how MISO's resource adequacy functions, it should be taken up as a generic issue so that others can participate in the dialogue and the broader ramifications of the Department's recommendations can be addressed. If such additional dialogue is pursued, Otter Tail does not recommend delaying approval of this resource plan.

III. ENERGY MARKET

The energy market is a viable resource solution. Market purchases are an effective means of meeting short-to-intermediate energy needs and as a hedge to load uncertainty. When Otter Tail models the energy market in Strategist, it is assuming a mix of bilateral contracts and the day-ahead or spot markets. Bilateral contracts are typically between utilities, are longer-term in nature, and involve financial authorization and risk assessment before completion. The Company would not advocate the sole use of day-ahead or spot markets for planning for customer energy requirements. Otter Tail routinely evaluates bilateral opportunities and enters into contracts when it is in the customer's best interest to do so. When determining levels of purchases and the related timing of those purchases, consideration is given to many market factors including estimated load growth, near and long-term weather forecasts, forward market prices, regional power supply availability, natural gas storage and price levels, and historical market trends for day ahead and real time prices.

Otter Tail currently has forward bilateral purchases for 2014 totaling 171,200 MWh, for 2015 totaling 432,700 MWh, for 2016 totaling 204,000 MWh, for 2017 totaling 203,200 MWh, and for 2018 totaling 204,000 MWh. As Otter Tail's resource planning process rolls forward beyond 2018 it will add additional bilateral contracts to add more price certainty. Over the last several years, Otter Tail has purchased from 10 to 20 percent of its annual energy needs from the MISO market.

While the Department characterizes this approach to market energy purcahses as "market reliance," this characterization is not correct. <u>The Company has enough resources through owned facilities, executed bilateral contracts, and load management to serve its load</u>, and therefore it is not "relying on the market" as the Department characterization suggests. Instead, the MISO market is used for energy purchases only when doing so reduces the cost of electricity to customers (e.g. when the market purchases can be made at prices lower than the costs of fuel for native generation). In other words, making the market available doesn't mean Otter Tail requires the market for its energy needs. Rather, it reflects the reality that Otter Tail can serve its customers from either its native generation and from its bilateral purchases, (which are together adequate to meet its energy needs if there are no opportunities in the market) AND it has the market available if there are opportunities for lower costs in the market. To ignore the market would only serve to distort modeling results. It would ignore the opportunity presented by the market access. The Department states that Otter Tail's Resource Plan fulfills about 16.5 percent of its energy needs from the energy market. This would be right in line with actual experience over the last several years. But this doesn't mean that Otter Tail would not have adequate energy available to it if the market were not available or if the opportunities diminished, which we do not expect. Otter Tail still has adequate native generation and bilateral purchases to meet its energy needs during the planning period.

IV. COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVE

The Department used incorrect values for Otter Tail's existing resources in Section F (3) of its Comments. The Renewable Energy Credit ("REC") amounts the Department used erroneously omitted Otter Tail's RECs attributable to the Ashtabula III wind PPA and RECs that Otter Tail had sold (thus under forecasting the RECs Otter Tail will have in future years). The Department arrived at its erroneous REC amounts by pulling information from the "active" RECs information from the M-RETS, which does not take into account 2013 vintage RECs that Otter Tail has sold (no longer "active" in Otter Tail's M-RETS account). Also, Otter Tail added the Ashtabula III PPA resource in October 2013, so there were only 3 months of generation from that resource reported in Otter Tail's M-RETS account.

Otter Tail includes below, for comparative purposes, the Department's original Table 13 and a corrected Table 13; along with the Department's original Table 14 and a corrected Table 14. The corrected tables quantify Otter Tail's expected RES compliance in all three jurisdictions through 2024 without regard to banked RECs. Including banked RECs and assuming no REC sales, Otter Tail shows expected RES compliance through the entire study period with a significant surplus of RECs (3.33 million RECs) at the end of the study period.

Table 13 from DOC comments - Minnesota

Year	MN REO/RES requirement MWh	2013 Renewable Generation (MWh)	Existing Generation less RES Surplus/(Deficit) MWh	Cumulative
				Beg Balance (including 2013 Gen)
				608207
2013	259,734	206,079	-53,655	348,473
2014	265,200	206,079	-59,121	289,352
2015	282,360	206,079	-76,281	213,071
2016	423,810	206,079	-217,731	-4,660
2017	414,630	206,079	-208,551	-213,211
2018	411,400	206,079	-205,321	-418,532
2019	429,250	206,079	-223,171	-641,703
2020	504,400	206,079	-298,321	-940,024
2021	509,200	206,079	-303,121	-1,243,145
2022	518,000	206,079	-311,921	-1,555,066
2023	515,600	206,079	-309,521	-1,864,587
2024	513,200	206,079	-307,121	-2,171,708
2025	638,750	206,079	-432,671	-2,604,379
2026	636,000	206,079	-429,921	-3,034,300
2027	633,750	206,079	-427,671	-3,461,971
2028	631,500	206,079	-425,421	-3,887,392

Corrected Table 13 - Minnesota

Year	MN REO/RES requirement MWh	Annual Renewable Generation (MWh)	Existing Generation less RES Surplus/(Deficit) MWh	Cumulative
				Beg Balance (including 2013 Gen)
				883940
2013	259,734	338,046	78,312	962,252
2014	265,200	413,460	148,260	1,110,512
2015	282,360	418,406	136,046	1,246,559
2016	423,810	418,406	(5,404)	1,241,155
2017	414,630	418,406	3,776	1,244,932
2018	411,400	418,406	7,006	1,251,938
2019	429,250	418,406	(10,844)	1,241,094
2020	504,400	418,406	(85,994)	1,155,101
2021	509,200	418,406	(90,794)	1,064,307
2022	518,000	418,406	(99,594)	964,714
2023	515,600	418,406	(97,194)	867,520
2024	513,200	418,406	(94,794)	772,727
2025	638,750	418,406	(220,344)	552,383
2026	636,000	418,406	(217,594)	334,789
2027	633,750	418,406	(215,344)	119,446
2028	631,500	418,406	(213,094)	(93,648)

Table 14 from DOC comments - Minnesota & Dakotas				
Year	MN REO/RES requirement MWh	2013 Renewable Generation (MWh)	Existing Generation less RES Surplus/(Deficit) MWh	Cumulative
2013	259,734	416,335	156,601	969,068
2014	265,200	416,335	151,135	1,120,203
2015	509,460	416,335	-93,125	1,027,078
2016	650,810	416,335	-234,475	792,603
2017	642,730	416,335	-226,395	566,208
2018	640,900	416,335	-224,565	341,643
2019	660,250	416,335	-243,915	97,728
2020	736,800	416,335	-320,465	-222,737
2021	743,000	416,335	-326,665	-549,402
2022	753,100	416,335	-336,765	-886,167
2023	752,000	416,335	-335,665	-1,221,832
2024	750,900	416,335	-334,565	-1,556,397
2025	877,550	416,335	-461,215	-2,017,612
2026	874,500	416,335	-458,165	-2,475,777
2027	873,150	416,335	-456,815	-2,932,592
2028	872,200	416,335	-455,865	-3,388,457

Corrected Table 14 - Minnesota & Dakotas				
Year	MN REO/RES requirement MWh	Annual Renewable Generation (MWh)	Existing Generation less RES Surplus/(Deficit) MWh	Cumulative
				883940
2013	259,734	639,678	379,944	1,263,884
2014	265,200	835,274	570,074	1,833,958
2015	509,460	845,265	335,805	2,169,763
2016	650,810	845,265	194,455	2,364,219
2017	642,730	845,265	202,535	2,566,754
2018	640,900	845,265	204,365	2,771,120
2019	660,250	845,265	185,015	2,956,135
2020	736,800	845,265	108,465	3,064,600
2021	743,000	845,265	102,265	3,166,866
2022	753,100	845,265	92,165	3,259,031
2023	752,000	845,265	93,265	3,352,297
2024	750,900	845,265	94,365	3,446,662
2025	877,550	845,265	(32,285)	3,414,378
2026	874,500	845,265	(29,235)	3,385,143
2027	873,150	845,265	(27,885)	3,357,259
2028	872,200	845,265	(26,935)	3,330,324

V. ADDITIONAL WIND RESOURCE

It appears that the United States Environmental Protection Agency's ("EPA's") recently proposed Clean Air Act Section 111(d) Emission Guidelines for Existing Sources ("EPA GHG Rules"), with its state-by-state implementation requirements, could have an impact on the size, location and timing of wind resource additions on the Otter Tail system. The EPA GHG Rules are the primary reason Otter Tail requested a 30-day extension for Reply Comments on the Resource Plan. Otter Tail plans to continue to monitor the rulemaking process and assess the potential impact this rule could have on the Company and its customers. The amount, location and timing of possible generation additions may be very dependent on the outcome of this rulemaking.

The EPA's proposed rulemaking sets state targets based on the amount of coal, NGCC, renewable energy, and energy efficiency within each state's geographical boundaries. The proposed rules utilize a calculation using each of these factors to determine a state's target and compliance with the rulemaking in the future. Depending on the outcome of these Rules and other related proceedings, such as state implementation plans and any multi-state compliance proceedings, there may be significant benefits if certain generation projects are located within certain states. There may be regret if a project were constructed earlier than necessary and it is determined later that the construction occurred in a state where the project's full contribution to the EPA goals are not realized.

The EPA issued the guidelines in June 2014, Comments are due by October 2014, and a final rule is expected in June 2015. States will then have until June 2016 to develop State Implementation Plans to determine how they plan to proceed (and have the option of additional time if a multi-state approach is determined). It is also likely that these rules will be the subject of litigation.

Over the course of the EPA proceeding, the rules outlined within the Notice of Proposed Rulemaking will change, and the end-state could be materially different than the initial proposal.

The Department Comments, which were filed before issuance of the EPA's Notice of Proposed Rulemaking, recommend that the Commission require Otter Tail to modify its Resource Plan to include 200 MW of wind (100 MW in 2017 and 100 MW in 2019). Otter Tail would not be opposed to an order allowing the addition of up to 200 MW of wind to its five year action plan assuming prices at the time of acquisition are cost-effective. However, it would be opposed to a requirement to initiate an RFP proceeding or build a specific amount of new wind until the outcome of the EPA 111(d) rules are more clear. For these reasons, Otter Tail recommend that any authority granted to add such resources include adequate flexibility to allow greater clarity of the EPA's 111(d) rules to develop.

VI. LEVEL OF DSM IN RESOURCE PLAN

The Department recommends that the Commission approve a resource planning DSM goal of 1.7 percent of retail sales. Otter Tail respectfully disagrees with that recommendation. As explained below, Otter Tail does not believe it is prudent or realistic to plan for 1.7 percent annual energy savings when historical averages and the DSM Potential Study fall far short of that goal. Otter Tail also notes that the Department's analysis mistakenly confuses generator savings data with meter savings data. When the correct data is considered, it further reflects that the Department's recommendation is not reasonable.

The Department indicates that Otter Tail achieved 1.7 percent energy savings in 2013, and that the Company achievements in the last five years suggest that a 1.7 percent energy savings goal is achievable. While the Company acknowledges that we have demonstrated a commitment to energy savings by achieving significant goals, we respectfully disagree that a 1.7 percent energy savings goal is achievable every year and should be modeled in the Resource Plan.

Otter Tail has requested the Department approve Otter Tail's 2013 energy savings (at the generator) of 1.67 percent, with actual approval pending. Record energy savings was achieved in 2013 resulting in the Company achieving energy savings in excess of goal. But as illustrated by the Department in Table 4, the Company's 5-year average has been less than 1.5 percent. One year of significant energy savings does not justify an assumption that these record savings can continue year-after-year.

Secondly, the Company's 2010 DSM Potential Study[13] indicates that the Company's 2013 accomplishments greatly exceed the market potential identified in the study. The 20-year cumulative energy savings impacts by 2030 represent 14.5 percent in the high case scenario, which on an annual basis is .725 percent of energy sales.

Thirdly, Table 4 on Page 18 of the Department's Comments displays the Company's Historical CIP Achievements and Costs for 2009 – 2013. The Department's footnote on page 18 indicates Table 4 displays Annual Credited Savings <u>at the meter level, which is incorrect</u>. These savings are at the generator, which means correct meter savings for 2013 is 33,108 MWh, or 1.55 percent savings, and generator savings of 35,792 MWh or 1.67 percent savings.

If the Department is recommending an energy savings goal of 1.7 percent at the meter, this translates to a goal of approximately 1.84 percent at the generator, a goal the Company has never achieved.

Lastly, the Department and utilities have worked consistently in past years to associate the Resource Plan objectives to Company CIP plan goals. Department Staff has indicated that Otter Tail does not need to refile its 2014-2016 CIP plan goals, and that future CIP filing energy goals will not be dictated by the Resource Plan energy savings objectives. Furthermore, the Department notes that the "0.2 percent additional DSM does not change the Department's preferred expansion path, i.e. the supply-side resources needed do not change"[14]. Yet the Company is reluctant to have a Resource Plan objective that varies from a budgeted CIP plan goal.

[13] Otter Tail Power (Minnesota) Demand Side Management Market Potential Study; December 20, 2010; Navigant Consulting
[14] Docket No. E017-RP-13-961, Page 21

While it may not seem like a significant difference, a Resource Plan objective of 1.7 percent is 113 percent of the CIP plan goal of 1.5 percent. Based on Otter Tail's 2014-2016 CIP plan, the difference between 1.5 percent and 1.7 percent is more than 4,182 MWhs, or roughly the energy savings of our single largest CIP program. Such a significant impact cannot be obtained easily, or assumed achievable without due consideration.

Otter Tail appreciates the Department's perspective on the costs to attain higher levels of energy savings. The Company does not dispute that our historical lifetime conservation cost per kWh has been below average energy costs. However, it is difficult to forecast with any confidence the costs to achieve a higher energy savings goal that has never been achieved or sustained, and that is significantly higher than research suggests is achievable. While the Company will strive to achieve higher goals, overall costs to achieve these higher goals are increasing. That fact must be balanced with our mutual desire to achieve a balanced energy portfolio of energy efficiency, renewables, and traditional resources. Otter Tail cautions that planning resources around a goal that has never been achieved or sustained is not prudent.

VII. SOLAR ENERGY STANDARD

The Solar Energy Standard ("SES") requires 1.5 percent of Minnesota retail electric sales to come from solar generation by 2020. The Company's intention is to meet the SES as cost effectively as possible while minimizing upward pressure on customer rates and cross subsidization between different classes of ratepayers. There is also a solar carve-out that requires that 10 percent of the SES come from systems less than 20 kW in size. Otter Tail notes that it is researching factors that may suggest that meeting its 10 percent small solar requirement by 2020 may be a challenge. Secondary research conducted by Otter Tail suggests that solar photovoltaic owners likely have higher levels of education and income exceeding $100,000. Otter Tail estimates approximately 5-8 percent of our customers have incomes greater than $100,000 and 18 percent have a 4-year degree. According to a study conducted by the NREL, 18 percent of pitched residential roofs and 65 percent of commercial roofs are feasible solar sites. The Company is currently evaluating strategies to meet the 10 percent small solar portion of the SES.

The Department recommends that the Commission require Otter Tail to modify its Resource Plan to include 21 MW of Solar in 2019. The Department also states that "…for the

SES to be cost effective, the cost of solar energy would have to be less than $75/MWh."[15] Otter Tail would not be opposed to adding solar resources to its five year action plan, up to the amount needed to demonstrate compliance with the SES, assuming prices at the time of acquisition are cost effective. Otter Tail is hesitant to state the amount of installed capacity needed, since there are a number of factors that would determine what is most cost effective for our customers. Some of those factors would include the solar resource (location dependent – net capacity factor), the type of system (fixed, single axis tracking, double axis tracking), and the installed cost of the resource. Otter Tail expects that the installed solar capacity needed for SES compliance to be between 20 MW and 30 MW depending on the location and type of solar installation/technology selected.

The recently proposed EPA 111(d) rules could also have an impact on the size, location and timing of solar resource additions on the Otter Tail system. As described earlier in these Comments, Otter Tail plans to continue to monitor the rulemaking process and assess the potential impact this rule could have on the Company and its customers. For the same reasons explained in the Additional Wind Resource section of these Reply Comments, above, the Company believes that clarity on the EPA rulemaking will be helpful in determining the correct location for all future renewable generation, including its solar additions. For these reasons, Otter Tail recommend that any authority granted to add such resources include adequate flexibility to allow greater clarity of the EPA's 111(d) rules to develop.

VIII. GREENHOUSE GAS EMISSION GOAL

The Department recommends that Otter Tail be required to provide an updated estimate of its compliance with Minnesota's greenhouse gas reduction goal once the Commission approves a specific way of estimating compliance. Otter Tail is in agreement with the Department on this recommendation.

[15] Docket No. E017/RP-13-961, Page 31

IX. FORECASTING ISSUES

A. Line Loss Factors

In its Comments the Department requested an explanation of differences in line loss factors in this proceeding (the 7 percent used in the forecasting analysis and the 11 percent factor the Department believed was referenced in Appendix B) and identify which line loss factor is the correct figure to use in this proceeding.

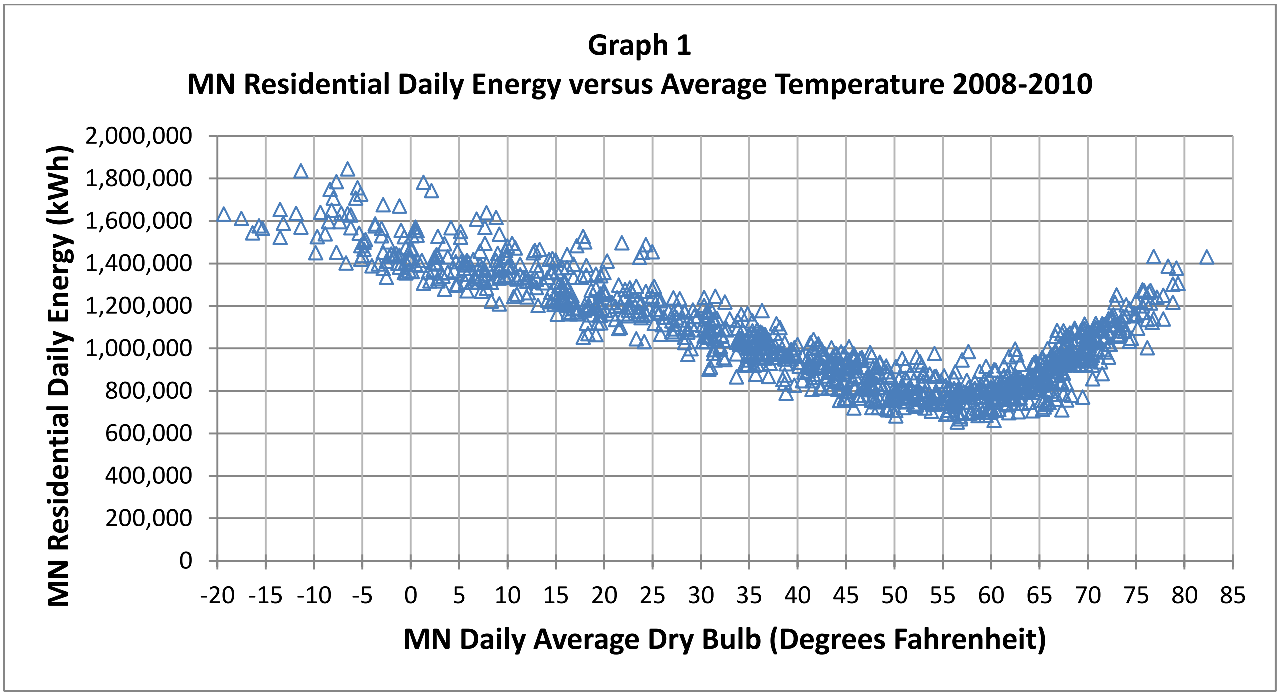
Otter Tail Power Company was unable to find a reference to an 11 percent factor as indicated in the Department's Comments. The Company had discussions with the Department and the Department confirmed that its request on this issue was the result of a mistake in the Department's review, and there is no line loss discrepancy in Otter Tail's filing. The Company confirms that 7 percent is the appropriate loss factor to use in the forecasting analysis.

B. Heating Degree Day Base

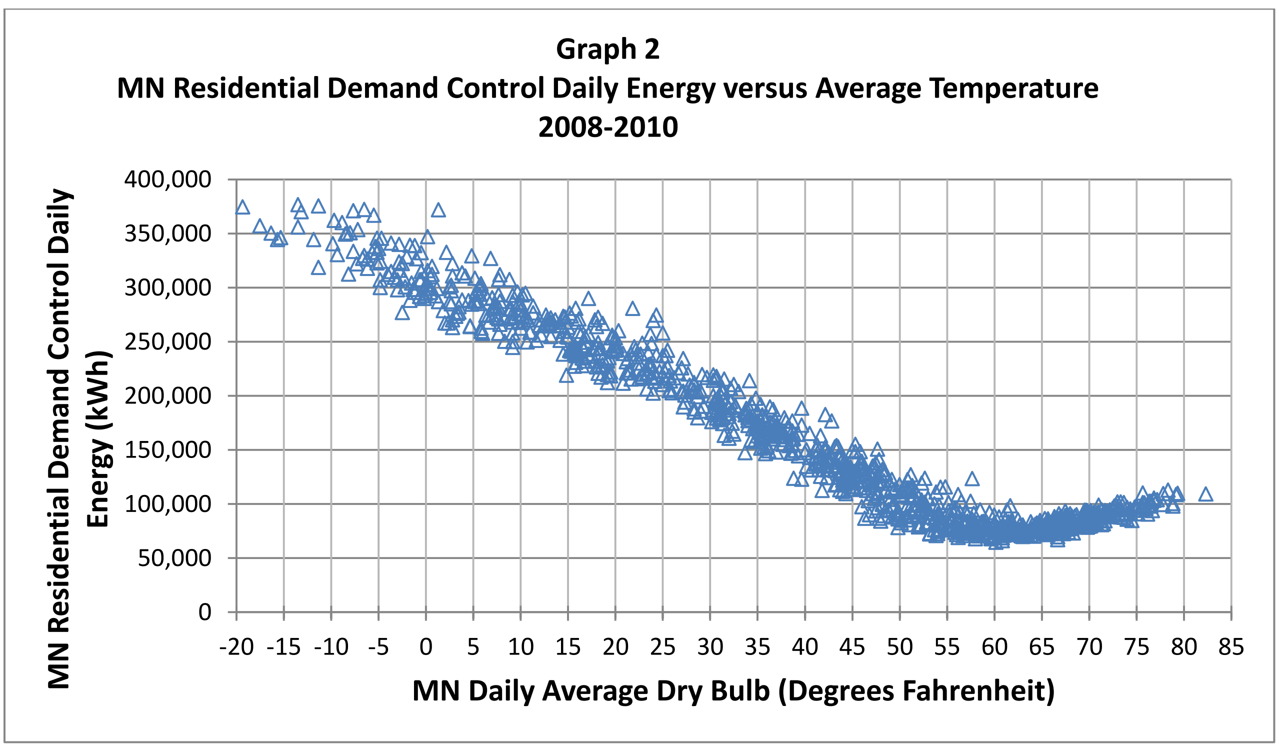
In its May 2, 2014 Comments the Department requested additional clarification from the Company on two variables that were used in the Company's sales forecast.

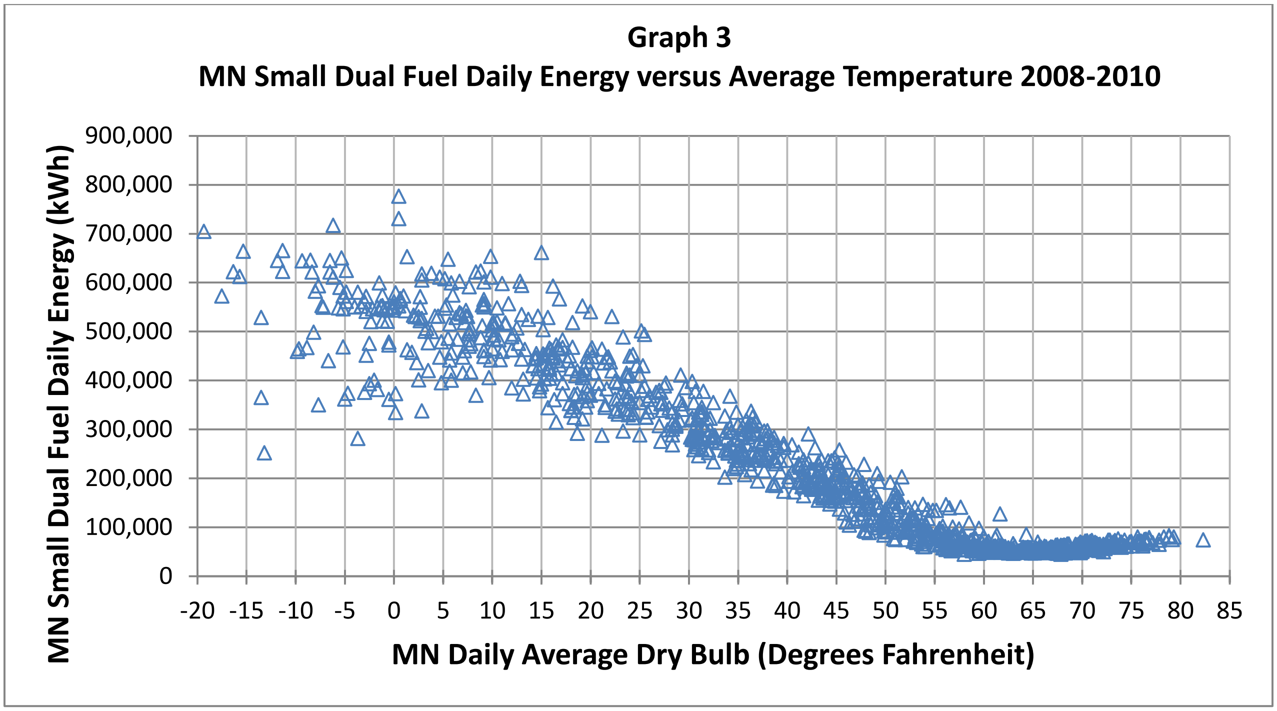
The first was the Company's use of 55 degrees Fahrenheit as its heating degree day ("HDD") base. HDD's are designed to measure heating load and the HDD base is the average temperature at which heating load begins. The Department pointed out that there is no single HDD base standard but that utilities generally use an HDD base of 65 degrees Fahrenheit in their estimates of energy consumption. The Department recommended that the Company fully explain, and justify, why it uses the HDD base of 55 degrees Fahrenheit instead of the more commonly used HDD base of 65 degrees Fahrenheit.

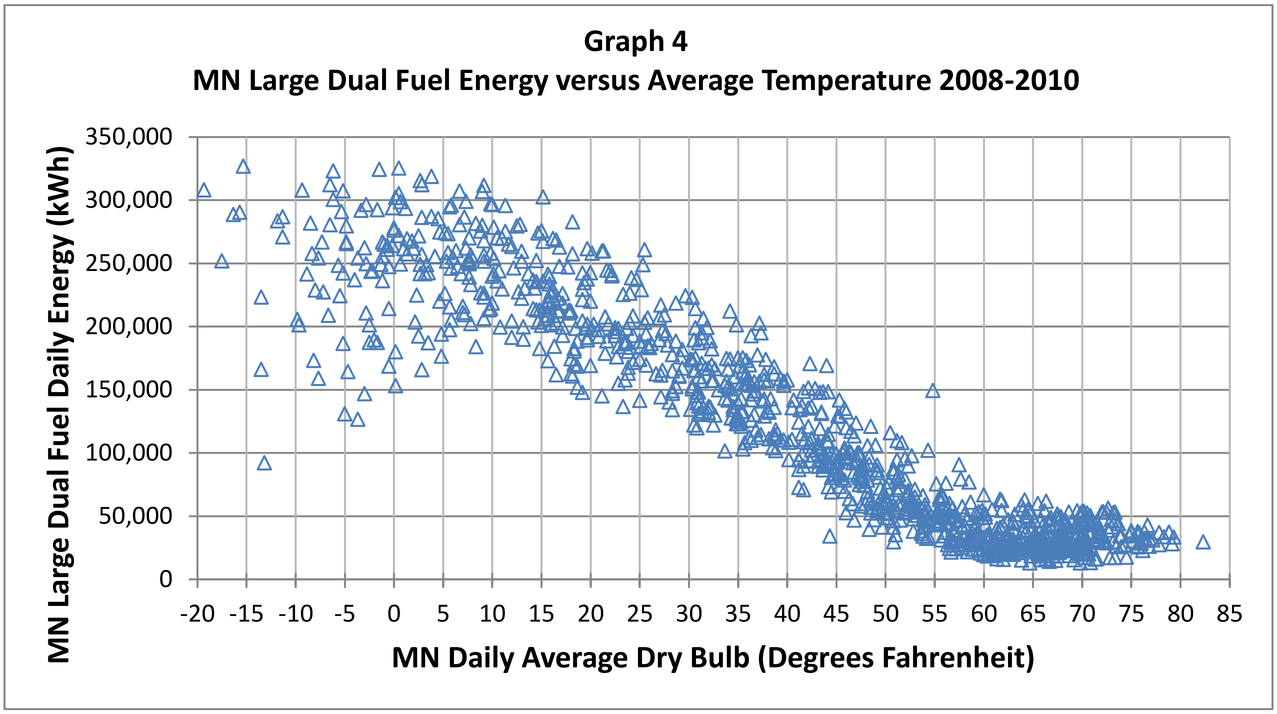
In making its decision to use an HHD base of 55 degrees Fahrenheit, the Company plotted daily energy use for various customer groups against daily average temperatures. An example of this plot is shown below as Graph 1. Graph 1 shows the plot for the Company's Minnesota residential customer group. The plot shows that daily energy use is at its lowest point at 55 degrees Fahrenheit. As the average daily temperature decreases from 55 degrees Fahrenheit the daily energy use increases. This provides support that the Company's Minnesota residential customers typically turn their thermostats on at a daily average temperature of 55 degrees Fahrenheit and that using an HDD base of 55 degrees Fahrenheit is appropriate for the Company's Minnesota residential customers.



The Company completed the same plots for other customer groups including its Residential Demand Control customers, Small Dual Fuel customers, and Large Dual Fuel customers. Similar results were seen across these customer groups. The plots for these customers are provide below as Graphs 2 through 4.







C. Weather Interaction Term

The second forecast variable the Department requested additional clarification from the Company on was the weather interaction term. The Department pointed out that the use of an interaction term is not an issue because the variable attempts to model a change in the relationship between a given independent variable (weather) and the dependent variable (energy consumption). However, in this case the variable specification created two independent variables that have the same data for parts of the historical period and the entire forecasting period. The Department expressed concern that using the same data in the two variables is likely to create correlation between the two variables which may impair the estimative power and overall stability of the models.

Given these potential concerns, the Department recommended the Company provide the following in these Reply Comments:

- A full explanation of what steps and analysis the Company conducted to verify that the weather interaction term did not impair the estimative power and stability of regression models; and
- A detailed explanation, including data if available, which supports a change in weather, or weather's impact on energy consumption, as suggested by the specification of the Company's weather interaction variables.

Because of increases in the Company's capacity control set point starting the winter of 2007 the Company's winter energy sales increased. The capacity control set point for January increased from 700 MW in 2006 to 715 MW in 2007, to 725 MW in 2008, and to 810 MW in 2009.

The impact of the capacity set point on winter energy sales was first noticed in modeling that the Company conducted during the early part of 2012. In that modeling, significant error was noticed in all winter months. For example, the error in the Minnesota residential use per customer model for January 2007 was 65 kWh with average model error, prior to adding the interaction term, of 42 kWh. The error for January 2008 and 2009 was 92 kWh and 217 kWh, respectively. In the 2012 model, weather normalized use per customer for January 2006, 2007, 2008, and 2009 was 1,315 kWh, 1,382 kWh, 1,435 kWh, and 1,565 kWh, respectively.

The interaction term was maintained in modeling done subsequent to the 2012 modeling, including the Resource Plan modeling, as long as the interaction term remained significant and no multicollinearity existed (see below).

To verify that the weather interaction term did not impair the estimative power and stability of the regression model the Company checked for multicollinearity as indicated by the significance of the T-Stat. A T-Stat between -1.96 and 1.96 for a given independent variable is an indicator of multicollinearity. Multicollinearity is correlation between two variables. No multicollinearity was found.

D. Coincident Peak Estimation

In its Comments the Department expressed concern about the Company's method used to estimate its MISO coincident peak demand. Specifically, the Department asked for clarification on whether the Company's method to estimate coincident peak is based on recommendations, or suggestions, from MISO. Also, the Department felt that the use of strictly July peak data to calculate the normal non-coincident peak weather data is not necessarily representative of past conditions.

The Company's method to estimate coincident peak is based on an example from MISO. MISO made no recommendation. The only stipulation MISO had was to use some sort of variable that would explain the non-coincident and coincident diversity rather than doing a simple historical average of non-coincident versus coincident demands. The coincident methodology employed by the Company has been used for the past two MISO planning years.

The Company agrees with the Department that the use of strictly July peak data to calculate the normal non-coincident peak weather data is not necessarily representative of past conditions. Using July to calculate normal weather was chosen by the Company because all summer non-coincident peaks are forecasted to occur in July. The Company understands that there is as likely a chance for the non-coincident peak to occur during August as during July. All non-coincident summer peaks from 2005 to 2012 occurred during either July or August. All coincident peaks except one occurred during July or August. Therefore, the Company feels it is appropriate to use July and August to calculate normal coincident weather but not June and September.

Regarding the Company's method to estimate coincident peak demand, the Department requested the Company update its coincident peak analysis originally provided in its response to Department Information Request No. 4 with 2012 and 2013 data. The Company has updated the analysis which can be found in Attachment 1 to these Reply Comments.

In its Comments, the Department asked for a detailed discussion regarding whether the Company believes the creation of a data set representative of historical MISO conditions is possible, from the Company's perspective, and whether the Company would be amenable to participating in this type of analysis with MISO.

The data set would require the aggregation of each MISO load serving entity's hourly load for the past 20 years. MISO has aggregated load since 2005 but any aggregation before that would require the load serving entities to provide it. The Company feels it is possible to accomplish but that it would be a very large undertaking requiring the participation of all MISO load serving entities and the coordination of MISO. Both MISO and the load serving entities would have to be convinced that an alternative method is worth the time and effort that will be required. If such an endeavor were undertaken, the Company confirms it would be amenable to participate.

E. Deployment of Demand Response

In its Comments the Department indicated that the Company's demand response and load management controls are dispatched by MISO and not by Otter Tail. The Department was concerned that the full allotment of accredited demand resources might not be available at the Company's system peak. The Department asked that the Company provide the following in Reply Comments:

- A detailed discussion of how MISO dispatches demand response and what, if any, say the Company has on the deployment of these resources on a non-coincident, either summer or winter;
- The Company's historical demand response deployment, by day, over the period since the Company registered load management with MISO;
- The Company's historical demand response deployment, by day, for five years before the Company registered load management with MISO; and
- A detailed discussion of how much demand response the Company believes MISO will have available, in the future, to account for the Company's non-coincident peak.

The Company has two demand response resources registered as Load Modifying Resources ("LMR's") with MISO. At the time the Company filed its Integrated Resource Plan, its firm service level customer was registered at 15 MW and its direct load control programs were registered at 15 MW.

Having these resources registered with MISO means that they must be available for use by MISO during all types of emergency events, including both capacity and transmission emergency events. Resources not available when called upon by MISO are subject to penalties unless the resource owner shows that the resource was otherwise deployed for economic or local reliability reasons.

Other than those limitations set in retail tariffs (i.e. water heating control is limited to 14 hours in a 24 hour period), the Company is not limited in its ability to deploy its demand response. Other than when it is directed by MISO for system wide emergency events, the

Company typically only deploys its demand response for economic purposes. Deployment for economic purposes occurs at times when the company would otherwise purchase energy at a market price exceeding the predetermined seasonal pricing point.

The Company can deploy its demand response for local transmission reliability purposes, without limitations set by MISO, but has not done so during the time since its demand response was first registered with MISO. Should its demand response be deployed sometime in the future for local transmission reliability purposes it would be limited to very small load pockets since the Company only has operating control of its low voltage transmission facilities.

Because of the way the MISO market operates there is no such thing as a local capacity event so there is no reason for the Company to deploy its demand response for local capacity reliability or in other words, its non-coincident system peak. MISO measures its supply and demand balance on a system wide basis. There is no reason, other than for economics, for the company to be concerned with its own systems supply and demand balance. The Company does not operate as an island. If the price of market energy is lower than a predetermined seasonal pricing point, the company takes advantage of the market to supply its needs.

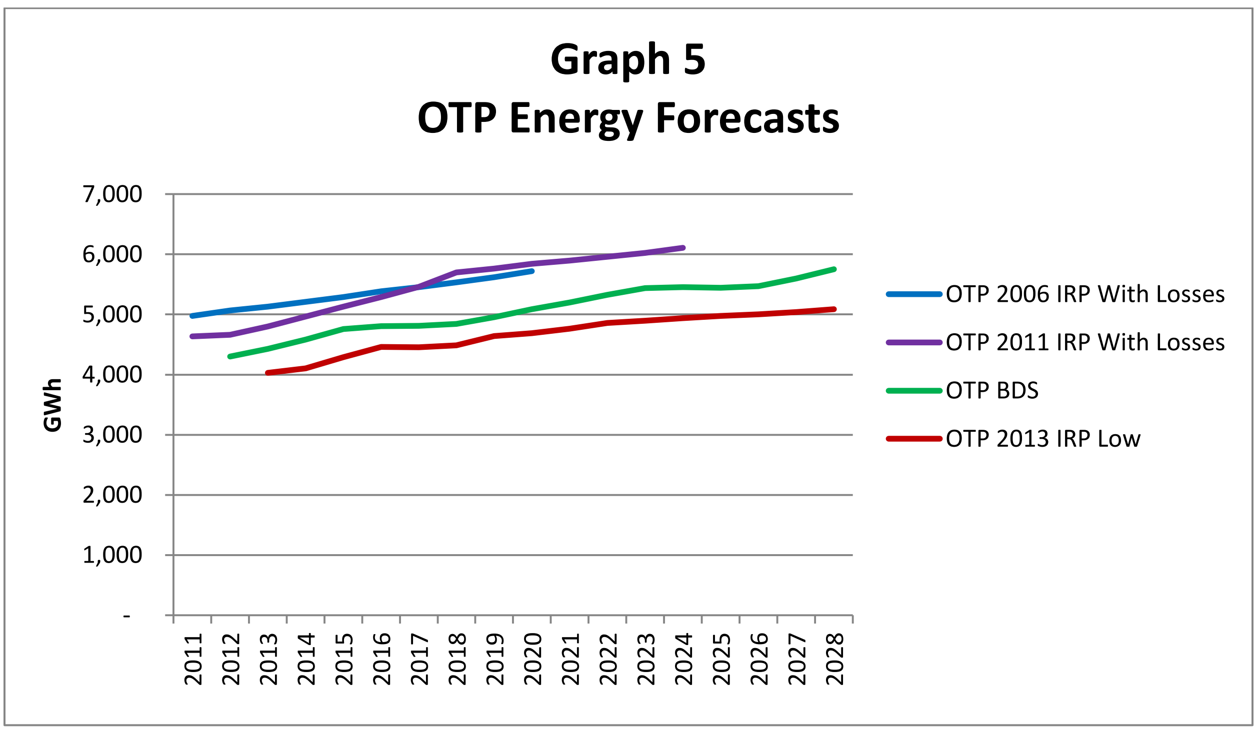
Attachment 2 shows the Company's daily demand response deployment from January 1, 2005 through May 31, 2014. The Company first registered its demand response with MISO starting June 1, 2010. The Company used two different sets of data for Attachment 2. From 2005 through 2008 it used "Net Controlled Load" data. From 2009 through 2014 it used "Load Management Control" data. Load Management Control data is more accurate but is not available prior to 2009.

The reasons for control are indicated in the far right column of the attachment. "Cap" means the Company controlled for capacity related purposes and that not all demand response customers were controlled prior to ending the control so the level of control did not reach its full potential. "Cap All" means that the Company controlled for capacity related purposes and that all demand response customers were controlled prior to ending the control so the level of control likely reached its full potential. "Econ" and "Econ All" means the Company controlled for economic related purposes. "Cap Econ" and "Cap Econ All" means the Company controlled for both capacity and economic related purposes. "MISO Test" means the Company controlled to obtain data for MISO capacity accreditation purposes and that the level of control likely reached its full potential.

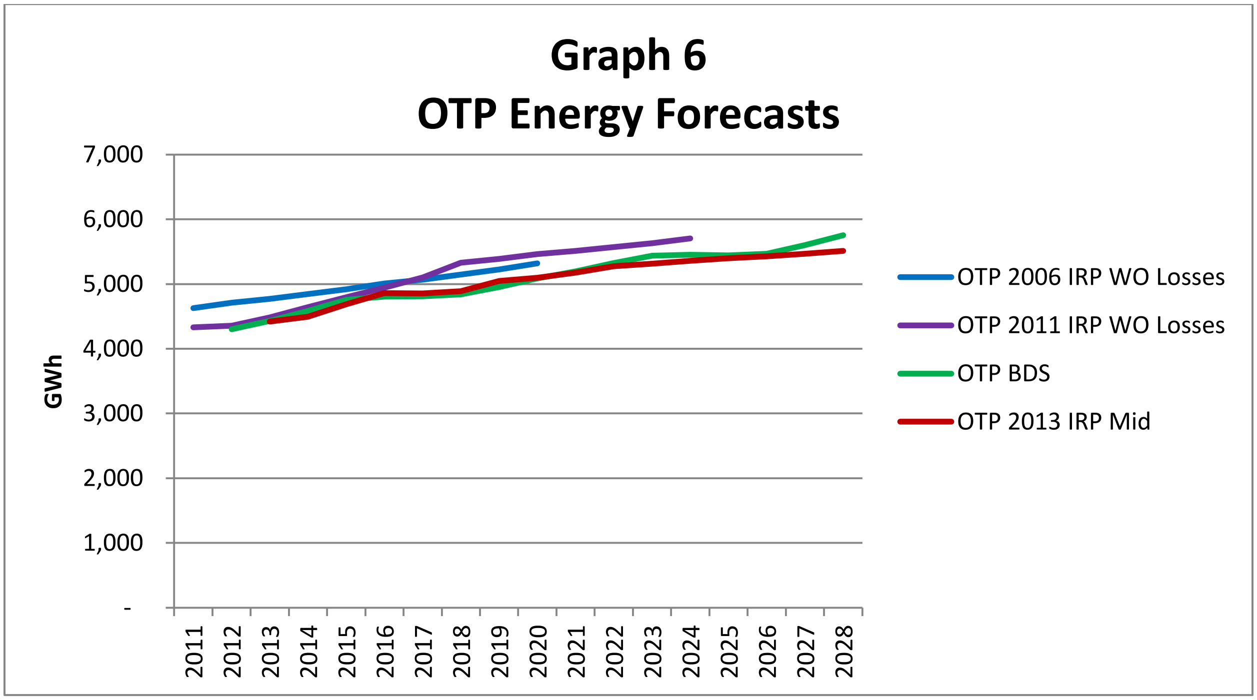
All capacity, economic, and MISO test control events from January 1, 2005 through May 31, 2014 were initiated by the Company and not by MISO. All capacity related deployment occurred prior to the effective date of Module E1 on June 1, 2012. Because of peak demand forecast changes under Module E1, the Company no longer had an incentive to deploy its demand response for capacity purposes. Any future capacity-related deployment of load control would be initiated by MISO.

X. UNRELIABLE LOAD FORECAST (MCEA)

In its Comments, MCEA asserted that "OTP's 2013 IRP is undermined by an unreliable load forecast." MCEA asserted further that "Over the last several resource planning related proceedings, OTP has continued to temper expectation for its load and energy demand growth and to reduce the starting point of its load forecasts even as the rate of growth remains roughly the same." MCEA provided a graph comparing four energy forecasts the Company used in past planning related proceedings. The graph MCEA provided is shown in Graph 5 below.



Graph 5 is misleading, because MCEA used inconsistent data relative to the four presented forecasts to produce the graph. The 2006 and 2011 Resource Plan forecast data that MCEA used included transmission and distribution losses which added 7 percent to the baseline forecast while the Baseload Diversification Study ("BDS") and 2013 Resource Plan did not include losses. The 2013 Resource Plan forecast data that MCEA used was the low forecast scenario while the 2006 and 2011 Resource Plan and BDS forecast assumed the baseline forecast. The graph shown below in Graph 6 shows the four forecasts on a comparable basis, without losses and assuming the baseline forecast for all four versions.



Graph 6 shows that Otter Tail has not "tempered expectations for its load and energy demand growth," as claimed by MCEA, but rather that its energy forecast shows consistency over the years, which enforces its credibility. The decrease in the Company's forecast from the 2011 Resource Plan to the BDS starting in 2016, as shown in Graph 6 is directly attributable to a lower forecast for the Company's large industrial customers.

Based on its misleading comparisons depicted in Graph 5, MCEA incorrectly asserts that "OTP continues to overestimate its load forecast." And based on its misleading comparison, MCEA goes on to recommend, as follows: "In light of evidence prior forecasts overestimated energy needs, OTP should be required to consider the effect of efficiency measure such as increasingly stringent building codes and appliance efficiency standards when estimating its load forecast."

Because Otter Tail has not overestimated prior forecasts and because its forecast models will implicitly project changes in building codes, the Company should not have to make additional duplicative adjustments to its forecasts as recommended by MCEA.

XI. OTHER ITEMS REQUESTED IN REPLY COMMENTS

A. Impact of Supreme Court's decision to uphold CSAPR

In the Minnesota Public Utilities Commission Information Request No. 3, Commission Staff requested that the Company "provide a discussion of the impact of the Court's ruling on CSAPR in the Company's reply comments." Below is that discussion.

On April 29, 2014, the U.S. Supreme Court issued its opinion in the litigation concerning EPA's Cross-State Air Pollution Rule ("CSAPR"), reversing the August 21, 2012 decision of the U.S. Court of Appeals for the D.C. Circuit that had vacated CSAPR. The Supreme Court's opinion does not remove or otherwise address the D.C. Circuit's December 30, 2011 order staying CSAPR. CSAPR has now been remanded to the D.C. Circuit for further proceedings; however, CSAPR will continue to be stayed until the D.C. Circuit takes further action. Therefore, at this time, the implementation and compliance dates for the rule are still unknown.

The CSAPR rule that was vacated in 2012 would have applied to Otter Tail's Solway gas peaking plant and the Hoot Lake Plant ("HLP") coal-fired facility in Minnesota. The primary impact of the rule would have been for HLP to acquire sulfur dioxide ("SO2") allowances to continue operating at standard historical levels. Otter Tail anticipates that this will continue to be the primary impact following a reinstatement of CSAPR.

Assuming that HLP ultimately receives the same level of SO2 allocations that the plant would have received in the vacated rule, the following table illustrates theoretical historical SO2 allowance shortfalls for the previous five years of operations.

Year	Total HLP SO2 Emissions (tons)	Theoretical HLP CSAPR SO2 Allowance Allocation (tons)	Theoretical SO2 Allowance Shortfall
2009	2187	1255	(932)
2010	3610	1255	(2355)
2011	3414	1255	(2159)
2012	2658	1255	(1403)
2013	3476	1255	(2221)

At this time the cost impact of purchasing allowances is unknown since CSAPR is a market based program, and the market has not yet been established. For the vacated CSAPR rule, EPA modeling suggested a market price of $600 per ton; however, since CSAPR was vacated there has been a substantial reduction in SO2 emissions in the CSAPR region that comprises Minnesota. Any pricing estimates are speculative until the D.C. Circuit completes remand proceedings, until it is known in what form the rule will be reinstated, and ultimately until an allowance market is established.

B. Using a smaller CC unit instead of a simple cycle

On page 37 of its Comments, the Department requested that "Otter Tail provide a discussion in reply Comments of whether a CC alternative sized between 200 and 250 MW is a reasonable alternative to consider." Smaller CC units have higher capital costs on an installed kW basis and less efficient heat rates than large CC units. Otter Tail continues to explore potential partnering arrangements with other utilities that would allow Otter Tail and its customers to capture the economies of scale and more efficient heat rates associated with larger CC units. Modeling performed by Otter Tail using smaller CC units showed that those units were not selected as cost effective. However, Otter Tail would be willing to offer alternative sized CC units in future Resource Plans to demonstrate that impact.

XII. CONCLUSION

These Reply Comments demonstrate the reasonability of Otter Tail's plan for meeting both the short-term and long-term needs of its customers in a cost-effective manner in accordance with the factors listed in Minn. Rules 7843.0500, subp. 3.

As these Reply Comments demonstrate, Otter Tail should not be required to add resources in excess of those required to meet MISO resource adequacy requirements. Additions in excess of those requirements would result in duplicative resources and significant additional costs to Otter Tail's Minnesota customers with no apparent additional system reliability. The Company has also shown that use of both bilateral contracts as well as the day-ahead market are part of the benefits of MISO membership and result in lower costs to all of the Company's customers. These Reply Comments also show that the use of the 1.5 percent CIP goal, which is mandated by statute and approved in the Company's 2013 CIP triennial filing, is the appropriate level of energy efficiency to be included in the resource plan.

For these reasons, Otter Tail requests that the Commission approve its proposed resource plan, and specifically include in its Order in this case the following Ordering points:

1. Otter Tail's use of the MISO resource adequacy construct and its method to estimate coincident peak is reasonable.
2. Otter Tail's continued use of bilateral energy contracts and the MISO day-ahead energy market does not put its customers at risk and minimizes their cost of electric energy and should not be limited to the first five years of the planning period.
3. Otter Tail's 1.5 percent energy efficiency goal as submitted and approved in its current triennial CIP plan is the appropriate and achievable level of energy efficiency for the Company.
4. Otter Tail's load forecast is reasonable, including its use of 55 HDD and provides a reliable expectation of future energy needs.
5. Authorization to construct 20-30 MW of solar energy by 2019 if cost-effective and clarity on how such resource additions will be treated under the EPA' s proposed 111(d) rules has been obtained.
6. Authorization to construct up to 200 MW of wind by 2021 if cost-effective and if clarity on how such resource additions will be treated under the EPA's proposed 111(d) rules has been obtained.

7. Authorization to construct up to 211 MW of combustion turbine (or combined cycle if found to be cost effective) by 2021.
8. Otter Tail will provide an updated estimate of its compliance with Minnesota's greenhouse gas reduction goal once the Commission approves a specific way of estimating compliance.
9. Find that Otter Tail's preferred plan is in compliance with Minnesota's Renewable Energy Standard through 2024.
10. Otter Tail will file its next Resource Plan by December 1, 2016

Dated: August 1, 2014

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: *<u>/s/ BRIAN DRAXTEN</u>*
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Otter Tail Power Company Coincident Peak Forecast Input Variables

Month	Year	MISOcpMW	NCP_MW	MISOcpTHIB	NCP_THIB	DF	ABS(THIB_Diff)
Jun	2005	493.207	604.098	68.558	76.576	0.183564676	8.018
Jul - MISO Annual Peak	2005	456.017	585.737	67.463	73.231	0.221464127	5.768
Aug	2005	550.068	605.967	73.691	75.805	0.092246509	2.114
Sep	2005	436.252	478.959	67.062	67.215	0.089165748	0.153
Jun	2006	431.716	549.332	65.266	71.791	0.214107614	6.525
Jul - MISO Annual Peak	2006	593.781	593.781	76.824	76.824	0	0.000
Aug	2006	473.727	536.649	70.757	71.322	0.11724969	0.566
Sep	2006	474.445	480.274	65.412	65.412	0.012136289	0.000
Jun	2007	493.679	594.224	72.682	75.394	0.169204472	2.712
Jul	2007	603.136	625.690	75.264	76.988	0.036046264	1.724
Aug - MISO Annual Peak	2007	473.974	554.917	68.873	70.217	0.145865487	1.344
Sep	2007	570.599	583.767	72.370	72.370	0.022557856	0.000
Jun	2008	459.285	492.904	69.270	69.270	0.06820615	0.000
Jul - MISO Annual Peak	2008	512.421	529.251	71.169	70.218	0.03179859	0.951
Aug	2008	501.747	557.799	68.588	70.900	0.100487315	2.313
Sep	2008	420.596	480.287	64.866	72.234	0.124281598	7.368
Jun - MISO Annual Peak	2009	523.666	550.965	69.111	69.111	0.049548753	0.000
Jul	2009	459.084	560.169	64.529	65.963	0.18045394	1.434
Aug	2009	493.234	606.803	67.557	73.523	0.187158257	5.967
Sep	2009	472.593	514.084	67.261	67.569	0.080708918	0.309
Jun	2010	545.040	551.225	69.772	69.088	0.011220006	0.684
Jul	2010	525.255	601.805	67.867	71.474	0.127200301	3.607
Aug - MISO Annual Peak	2010	569.519	677.320	75.020	74.670	0.159158319	0.351
Sep	2010	484.219	486.065	66.330	62.923	0.003797075	3.408
Jun	2011	561.884	615.654	69.960	74.329	0.087336649	4.369
Jul - MISO Annual Peak	2011	621.390	676.429	79.118	80.595	0.081366782	1.478
Aug	2011	572.909	649.322	73.439	71.567	0.117680603	1.873
Sep	2011	550.059	550.059	71.196	71.196	0	0.000
Jun	2012	542.499	543.965	69.362	69.362	0.002694961	0.000
Jul - MISO Annual Peak	2012	573.269	636.552	72.882	76.652	0.099414652	3.770
Aug	2012	566.853	605.707	71.488	72.354	0.064146416	0.865
Sep	2012	532.552	533.757	66.827	66.827	0.002257095	0.000
Jun	2013	538.765	584.187	71.520	71.779	0.077753419	0.258
Jul - MISO Annual Peak	2013	633.004	633.004	76.446	76.446	0	0.000
Aug	2013	632.361	640.807	76.379	76.822	0.013180841	0.443
Sep	2013	511.288	615.178	66.860	71.269	0.168877697	4.409
				Y	X	Y	X

Step #1: Regression on DF and ABS(THIB_Diff)

	Coefficients
Intercept	0.04722379
ABS(THIB_Diff)	0.019817133

Step #2: Regression on MISOcpTHIB and NCP_THIB

	Coefficients
Intercept	17.58863021
NCP_THIB	0.732961909

Step #3: Determine the CP Weather

Peak Month:	Jul-13
Normal NCP_THIB:	72.85426332
MISOcpTHIB:	70.98803012
ABS(THIB Diff)	1.866233199

Step #4: Determine the Coincident Peak

Peak Demand Forecast July 2013:	644
ABS(THIB Diff):	1.866233199
DF:	0.084207181
Coincident Factor:	0.915792819

CERTIFICATE OF SERVICE

RE: In the Matter of Otter Tail Power Company's 2014-2028 Integrated Resource Plan
Docket No. E017/RP-13-961

I, Wendi A. Olson, hereby certify that I have this day served a copy of the following on Dr. Burl W. Haar and Sharon Ferguson by e-filing, and to all other persons on the attached service list by electronic service or by first class mail.

Otter Tail Power Company
Reply Comments

Dated this **1st** day of **August 2014**.

<u>/s/ WENDI A. OLSON</u>
Wendi A. Olson
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