MINNESOTA DEPARTMENT OF COMMERCE

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July 31, 2014 **PUBLIC DOCUMENT**

Burl W. Haar
Executive Secretary
Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E001/RP-14-77

Dear Dr. Haar:

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

Interstate Power and Light Company's 2014-2028 Integrated Resource Plan.

The petition was filed on March 31, 2014 by:

Paula N. Johnson
Senior Attorney
Interstate Power and Light Company
200 First Street SE, PO Box 351
Cedar Rapids, IA 52406-0351

The Department recommends **approval with modifications**. The Department is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Rates Analyst

CS/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E001/RP-14-77

I. INTRODUCTION

A. OVERVIEW OF THE FILING

Minnesota Rules part 7843 requires electric utilities to file proposed integrated resource plans (IRP) every two years. On May 13, 2013 the Commission issued its *ORDER FINDING BASELOAD DIVERSIFICATION STUDY IN COMPLIANCE WITH 2012 RESOURCE PLAN ORDER, SETTING DATE FOR NEW RESOURCE PLAN, AND SETTING FURTHER REQUIREMENTS* for Interstate Power and Light Company's (IPL or Company) Baseload Diversification Study (Docket No. E001/RP-08-673). Order Point 2 stated that:

> IPL shall make its next resource plan filing in the first quarter of 2014, after the Company has received a decision from the Iowa Utilities Board regarding its Marshalltown Generating Station.

On February 4, 2014, IPL submitted a Notice of Changed Circumstances and stated that it would file its next IRP in March 2014. IPL submitted the instant filing on March 31, 2014.

B. COMPANY BACKGROUND

Interstate Power and Light Company is a regulated utility company of Alliant Energy Corporation. IPL serves more than 525,000 electric customers and more than 230,000 natural gas customers in Iowa and Minnesota. IPL's customers have a non-coincident peak (NCP) of 3,121 MW. After reductions for demand response and use of the coincident peak (CP) with the Midcontinent Independent System Operator (MISO) for planning, IPL's resource adequacy obligations are 2,896 Zonal Resource Credits (ZRCs). Approximately 92 percent of IPL's electric customers are in Iowa and about 8 percent are located in Minnesota. IPL sold its Illinois service territory in 2007 but still serves that load as a wholesale supplier.

IPL owns over 22,000 miles of electric distribution line, and all or parts of generating units capable of producing approximately 2,495 ZRCs towards MISO's resource adequacy requirements. IPL sold its transmission assets in 2007 to ITC Midwest LLC, a wholly-owned subsidiary of ITC Holdings Corp. IPL also sold its 70 percent share in the Duane Arnold

Energy Center (DAEC) nuclear plant to the FPL Group, through FPL Group's subsidiary NextEra Energy Resources.[1] IPL is currently installing the approximate 650 MW Marshalltown Generation Station (MGS) combined cycle facility with an expected in-service date of spring 2017. IPL entered into an agreement, subject to regulatory approval,[2] with Southern Minnesota Energy Cooperative (SMEC) for the transfer of all of IPL's Minnesota electric distribution assets and operations to SMEC. IPL proposes to enter into a 10-year agreement to provide all electric power needed to serve customers transferred to SMEC.

C. SUMMARY OF IPL'S PLANNING PROCESS

IPL used the following steps in its 2015-2029 IRP planning process:

- IPL developed an energy and demand forecast for three different levels of demand for electricity (high, base, and low).
- IPL converted its non-coincident peak (NCP), which is IPL's peak, to MISO's coincident peak CP (the amount of IPL's load at the time of MISO's peak). IPL compared the system's CP, including system reserve requirements (currently about 4.5 percent) to existing capability to determine the preliminary resource needs.
- IPL developed alternatives to fill the resource needs:
  - renewable electricity;
  - demand-side management (DSM) at four levels (low, base, medium, and high);
  - conventional supply-side generation; and
  - short-term power purchase agreements (PPAs).
- IPL used the Electric Generation Expansion Analysis System (EGEAS)[3] model to evaluate all combinations of the alternatives to determine the optimal expansion plan considering a variety of risks and policy requirements.[4] IPL conducted its analysis under three different CO_2 costs: no carbon costs, Wood Mackenzie's estimate of 2023 carbon prices ($16.01 per ton beginning in 2023, and the midpoint of Minnesota carbon regulation estimates ($21.40 beginning in 2017).[5]
- After consideration of costs, reliability, and risks IPL determined the Company's preferred plan.

[1] Central Iowa Power Cooperative has a 20 percent ownership, with Corn Belt Power Cooperative holding the remaining 10 percent ownership.
[2] For example, IPL file a petition for approval with the Commission in Docket No. E001/PA-14-322.
[3] EGEAS is a capacity expansion model that considers the addition of different types of power plants and chooses an expansion plan that minimizes the present value of revenue requirements (PVRR) for a 15-year planning period plus a 35-year extension period.
[4] For example, Minnesota Statutes require electric utilities subject to resource planning to evaluate the cost of meeting 50% and 75% of their future resource need through the use of renewable and demand-side resources.
[5] The Commission set a start date of 2019 for estimated costs of complying with carbon regulations, but IPL's EGEAS modeling uses 2017 as the start date. Applying the value early (2 years) does not have a material effect on IPL's expansion plan.

D. IPL'S PREFERRED PLAN

IPL's proposed plan is described in detail on pages 6-2 – 6-4 of its petition and includes:

- Using existing owned generation with the exceptions of propose retirements, in the near term, of the units noted below:
  [TRADE SECRET DATA HAS BEEN EXCISED]
- Implementing Ottumwa Generating Station capacity and efficiency upgrades as proposed in the 2010 Resource Plan, as well as a Scrubber and Baghouse installed by the end of 2014. For modeling purposes, a potential 2020 SCR is assumed, but no formal decision has been made;
- Implementing Lansing Unit 4 capacity and efficiency upgrades through 2017 as proposed in the 2010 Resource Plan, as well as a Scrubber installed by mid-2015 in addition to the existing SCR and Baghouse installation;
- Modifications at MidAmerican Energy Company (MidAmerican) operated units Neal 3, Neal 4, and Louisa as proposed by MidAmerican
- Complete a fuel switch at Kapp 2 from coal to natural gas in the spring of 2015. For modeling purposes, Kapp 2 is assumed to be retired in 2025, but no formal decision has been made.
- The installation of [TRADE SECRET DATA HAS BEEN EXCISED];
- The installation of [TRADE SECRET DATA HAS BEEN EXCISED];
- The completion of the approximate 650 MW MGS combined cycle plant in the second quarter of 2017;
- A fuel switch for the Sutherland combustion turbine (CTs) from oil to natural gas preceding the installation of the MGS.

- The purchase of short term capacity in 2015 and 2016 as needed before the installation of the new combined cycle unit;
- Using forecasted DSM;
- In the long term:
    - o Adding incremental renewable generation (for example, the reference cases for all Carbon scenarios select 1,100 MW of wind);
    - o Adding new generating units (for example, the reference cases for all Carbon scenarios select a nominal 600 MW combined cycle plant in 2025);
    - o Satisfy the Minnesota Solar Energy Standard;
    - o For modeling purposes, the Sutherland CTs 1, 2 and 3 are assumed to retire in 2028, but no formal decision has been made;
    - o For modeling purposes, Red Cedar CT is assumed to retire in 2027, but no formal decision has been made; and
    - o Completing existing purchase power contracts, and evaluate possible extensions of wind and nuclear contracts;

As stated above, IPL relied on EGEAS runs that considered a variety of risks and policy requirements. The expansion plan that relies on the base case assumptions and the midpoint of the Minnesota carbon regulation estimates is shown below in Table 1:

Table 1: IPL Base Assumption with Minnesota Midpoint Carbon (MW)

	1 yr pk pwr purc	CT-88	CT-192	CC-300	CC-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	604.701	0	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**300**	**0**	**0**	**604.701**	**0**	**0**	**0**	**1100**	**10**	**0**	**647.599**

“CT” stands for “combustion turbine” while “CC” stands for “combined cycle” which is generally dispatched more frequently than a CT.

II. DEPARTMENT’S ANALYSIS

A. OVERVIEW OF ANALYSIS

Minnesota Statutes §216B.2422, subd. 4 states:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan … unless the utility has demonstrated that a renewable energy facility is not in the public interest.

The Department applied this standard in our analysis to ensure that any Department recommendation for a new or refurbished nonrenewable energy facility meets this requirement regarding the public interest.

While IPL used a valid capacity expansion model (EGEAS), the Department did not review in detail whether IPL used EGEAS in an analytically sound manner, since the Department performed its own modeling. Therefore, the Department has no comment on the ability of IPL’s EGEAS modeling to support approval of a new or refurbished nonrenewable energy facility.

To review IPL’s IRP, the Department:

- evaluated IPL’s energy and demand forecast;
- conducted its own capacity expansion modeling analysis using Strategist and compared it to IPL’s analysis;
- evaluated IPL’s compliance with the renewable energy standard; and
- assessed IPL’s consideration of environmental issues.

Based on this analysis the Department reached the following conclusions:

- IPL’s energy and peak load forecasts are satisfactory for planning purposes.
- With the use of surplus RECs currently allocated to Iowa, the Company would need to acquire additional renewable generation by 2018.
- Under the Department’s preferred plan, IPL would have sufficient renewable generation to meet Minnesota’s renewable energy standard requirements without relying on Iowa’s renewable energy credit allocation.
- IPL’s proposed expansion plan, as modified by the Department, is reasonable.
- IPL is adequately complying at this time with pending state and national environmental legislation that impacts the electric utility’s operations.

B. ASSESSMENT OF ENERGY AND DEMAND FORECASTS

1. Overview

IPL's energy and peak demand forecasts are based on Ordinary Least Squares (OLS) regression models. The Company used OLS regression in previous IRP filings, but IPL made several changes to its method in the current IRP. These various changes are detailed in Appendix 2A, Page 11 of 13, of IPL's initial *Petition* and are discussed in greater detail throughout this section.

In terms of the energy forecast, IPL estimated energy consumption, by rate type (*e.g.,* Residential), as a function of weather (heating degree days and cooling degree days), monthly dummy variables, and economic variables where applicable. The Company conducted these energy forecasts both at the IPL system level and at the Iowa jurisdictional level. This approach allowed IPL to estimate Minnesota-specific use based on the difference between total system consumption and Iowa jurisdictional consumption; this approach is a departure from the sales allocation method used in previous IRP filings.[6]

The Company developed its peak demand[7] by forecasting demand at the peak by some of its largest customers individually with the remaining customers' demand forecast developed through regression techniques. IPL's peak demand forecast is based on a three-stage process. The regression modeled demand is calculated based on the results of the Company's monthly, annual, and seasonal regression models. The demand forecast in this IRP includes interruptible and direct load control, which is a departure from previous IRP filings where these load management tools were excluded from the forecasting. IPL stated in its *Petition* that including interruptible and direct load control in the peak demand analysis creates a theoretical peak and leads to fewer adjustments to the demand data.

The estimation period and corresponding input data for each regression model (both energy and peak demand) are over the same time period, January 2003 to August 2013.[8] The Company stated in its filing that the weather data is obtained from the Weather Underground website and is from the Cedar Rapids, Iowa weather station.[9] The Department reviewed the Weather Underground website and it appears to conform to the weather data used by IPL.[10] IPL used historical weather (heating degree and cooling degree days) and 20-year normal weather over the period from 1993 to 2012 to estimate normal weather conditions during the forecasting period. These weather data, both historical and normal, are sourced from the same provider, which is an improvement from previous IRP filings where IPL used historical data from one data source and calculated normal weather

[6] In previous IRP filings, the Company used historical sales, by State, to allocate forecasted energy sales to the appropriate jurisdiction.
[7] In this discussion, "peak demand" refers to IPL's peak, which MISO calls a utility's non-coincident peak.
[8] In previous IRPs, IPL used different estimation periods for its various regression models. The regression models in this IRP have consistent estimation periods.
[9] www.wunderground.com.
[10] IPL provided the raw weather data used in its regression models and normal weather calculations in its responses to DOC Information Request Nos. 2 and 4 filed on July 1, 2014.

from a different data source. The Company obtained its economic data from IHS Global Insight.[11]

In IPL's most recent rate case (Docket No. E001/GR-10-276), the Department identified issues regarding the Company's data collection and regression estimates. Through the course of that proceeding, the Department and IPL reached agreement on issues that will be addressed in future regulatory filings. IPL was also required, as part of the April 17, 2007 *Order* in Docket No. E001/RP-05-2029 to provide certain data and information in its next IRP filing, Docket No. E001/RP-08-673. In its June 30, 2011 *Comments* in Docket No. E001/RP-08-673, the Department recommended that the Company continue to provide the data requested in the April 17, 2007 *Order* in future integrated resource plans. The Department reviewed the Company's initial filing and confirms that IPL complied with all data filing requirements in this docket.

2. IPL's Energy Forecast

The Company changed its method for conducting its energy forecast since the 2012 Baseload Study and 2010 IRP. Previously, IPL used separate short-term and long-term regression models, and then blended the results together, to estimate energy sales in the IRP forecasting period. The Company concluded that this method added complexity to the estimation; as such, IPL modified its approach. In this filing, the Company used a single, short-term regression model as the base for the long-term forecast, which is based on the growth rate calculated in the short-term forecast. IPL forecasted its short-term energy requirements, for both the IPL system and IPL-Iowa, over the period from September 2013 to December 2018 using historical data from January 2003 to August 2013. IPL then used the calculated growth rate from the regression output to estimate sales over the period from January 2019 to December 2029.

The results of the Company's forecast suggests that IPL's total system energy need in the Base Forecast will grow at an annual average rate of 0.90 percent for the period 2014-2029. The average growth rate of 0.90 percent is slightly higher than the expected growth rate of 0.76 percent over the period 2012-2027 projected in the Baseload Study. Figure 1 below compares the two energy requirement forecasts.

[11] These data were provided in the Company's response to DOC Information Request No. 2, filed on July 1, 2014.

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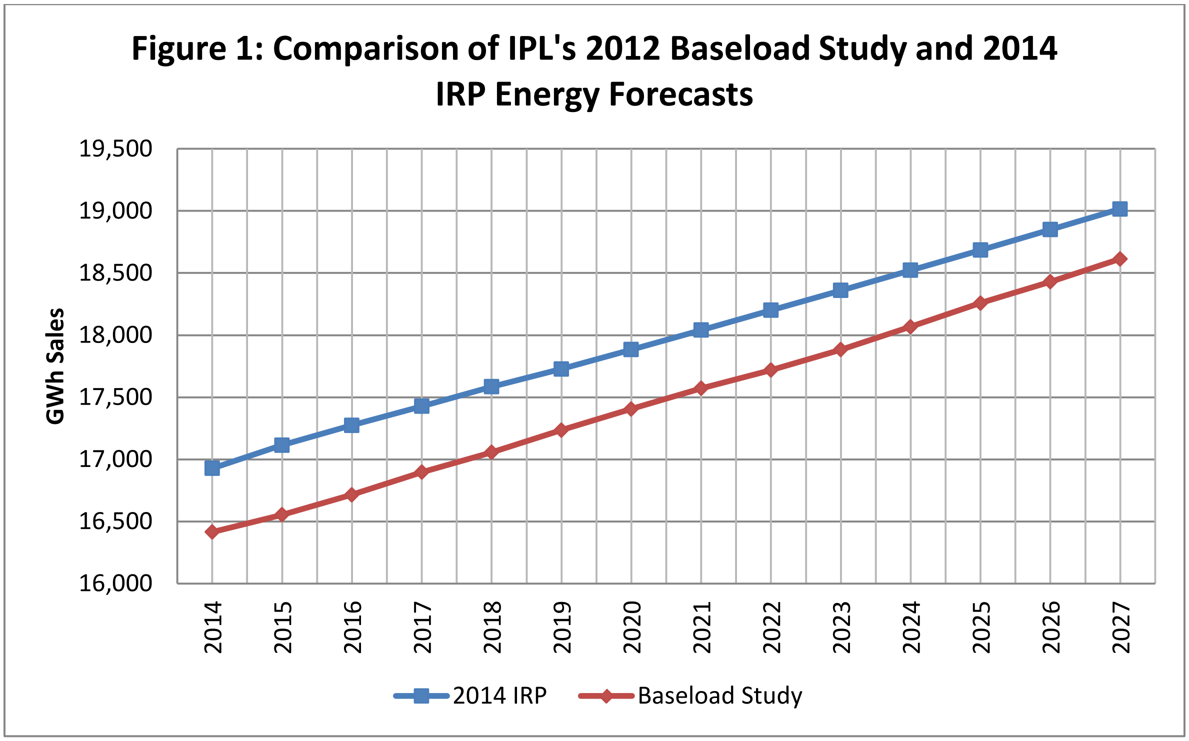

In its *Petition*, the Company stated that the primary reason for the increase in the energy forecast since the Baseload Study is related to the retention of a large customer and other large customer expansions that were not expected when the Baseload Study was completed. IPL also stated that the current energy forecast is lower than the energy forecast presented in the 2010 IRP, which the Company stated was due to lower short-term growth rates.

The Department concludes that the results of the Company's energy sales forecast are acceptable for planning purposes.

3. IPL's Demand Forecast

As noted above, IPL developed its peak demand by forecasting energy use at the peak by some of its largest customers individually with the remaining customers' demand forecast developed through regression techniques. The regression techniques were based on a three stage process of monthly, seasonal, and annual regression models which IPL then combined together to create the modeled peak demand. This approach represents a change from previous IRP filings when the Company estimated peak demand with a single regression model. IPL then added the individually forecasted demand results and modeled demand results together to arrive at total system demand.

IPL forecasted that peak demand in the base forecast would grow at an annual average rate of 0.86 percent for the period 2014-2029. This level represents a small increase (0.04

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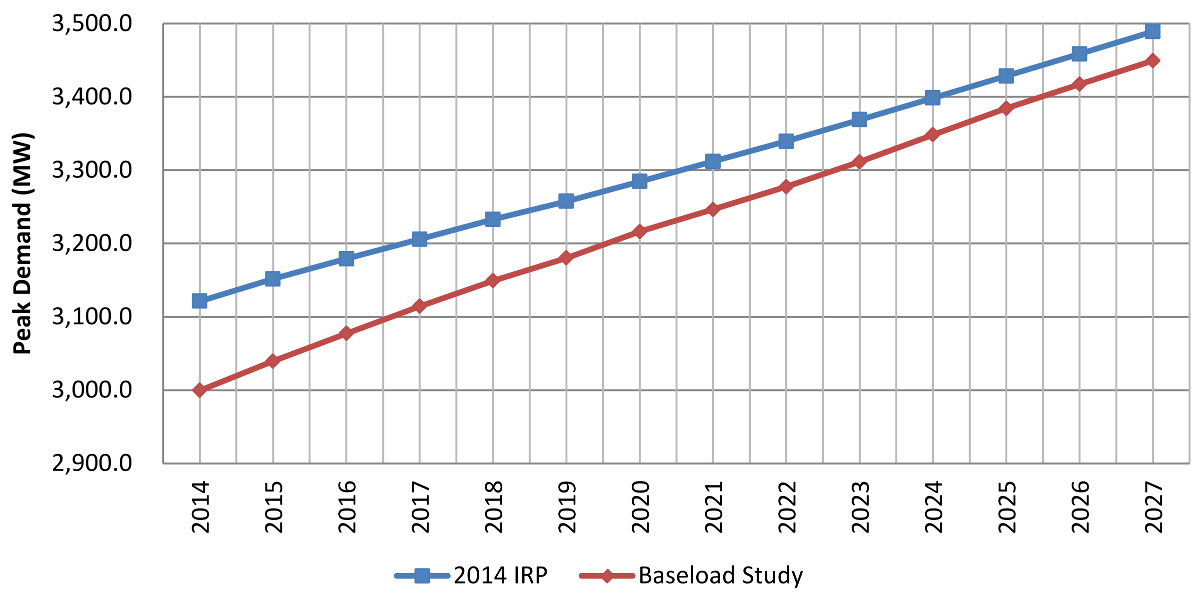
percent) in the average growth (0.82 percent) that IPL estimated in the Baseload Study.[12] Figure 2 below illustrates IPL's peak demand forecast and how it compares to the peak demand forecast in the Baseload Study.

Figure 2: Comparison of IPL's 2014 IRP and 2012 Baseload Study Peak Demand Forecasts



The peak demand forecast in the current IRP is higher than the projected forecast in the Baseload Study. IPL also stated in its filing that the 2014 IRP peak demand forecast is higher than the demand forecast in the 2010 IRP. The Company stated that the current demand forecast is higher than the previous two forecasts (2010 IRP and Baseload Study) because IPL was able to retain large wholesale customers and because large customer expansions occurred since the last two IRP forecasts were conducted.

As noted earlier in this section, IPL's peak demand forecast is based, in part, on a three stage regression analysis. The monthly model is based on monthly peak demand data (the date from each month with the highest demand) over the period from January 2003 to August 2013, the seasonal model is based on monthly peak demand data (the date from each month with the highest demand) from the summer months (June through September) over the period from June 2003 to August 2013, and the annual model is based on annual peak data (date during the year with the highest demand) over the period from January 2003 to August 2013. IPL then averaged the demand results from the annual and seasonal models to estimate average summer peak demand, which corresponds with historical peak demand on the IPL system. The Company then translated this seasonal peak estimate into

[12] IPL forecasted a *decrease* in energy sales growth compared to previous IRP filings and an *increase* in demand growth compared to previous IRP filings. This result may seem unusual at first glance, but it is not entirely unexpected. In simple terms, the results forecasted by IPL indicated that the Company anticipates sales, over the course of a year, to go down, but the sales that do occur will be more focused on peak periods.

monthly demand by using the results of the monthly demand model to create a representative demand profile for the entire calendar year.[13]

Upon reviewing this approach, the Department was concerned by the results of the annual model as this model does not have sufficient observations to ensure a large sample size. A large sample size is necessary because the test results and estimates from a regression model are predicated on a large sample size. The impact of the sample size on the peak demand forecast can be quantified by removing the annual forecast results from the Company's analysis. The Department removed the annual forecast results from IPL's peak demand calculations and the resulting demand forecast was only 0.1 percent greater than the forecast filed by IPL. As a result, the Department confirmed that IPL's use of the annual forecast, despite sample size concerns, does not have a material negative impact on the demand forecast.

The Department concludes that the results of the Company's demand forecast are acceptable for planning purposes.

4. Demand-Side Management

IPL did not make explicit adjustments for DSM in either its energy or peak demand forecasts as IPL assumed that the impacts of current programs were captured in the historical input data. In addition, the Company assumed that future conservation programs would be similar to current programs and impacts would likely be consistent with existing programs.

This method is similar to what IPL used in previous IRP filings. Further, the Company supported the use of implicit DSM (*i.e.,* no explicit post-regression adjustment for DSM) by comparing implicit DSM (calculated as the average of DSM over the previous five years) to the annual DSM impacts forecasted in its Minnesota and Iowa conservation filings. When implicit and explicit DSM are compared to total energy on the IPL system, there is a less than 1 percent difference in the impact of DSM on energy sales. As such, the Department concludes that IPL's use of implicit DSM is acceptable.

5. MISO Coincident Peak

Beginning in June 2013, MISO revised its resource adequacy construct. Specifically, MISO changed its peak demand construct from a monthly construct based on a non-coincident peak demand (*i.e.,* based on an individual load-serving entity's peak demand) to an annual construct based on the level of each utility's demand at the time of MISO's coincident peak demand (*i.e.,* the utility's contribution to the total aggregate demand for the entire MISO footprint on the day that MISO's system has the highest load).

Traditionally, the Department evaluated a utility's resource plan to ensure that the utility had adequate resources to cover its individual 50/50 system capacity forecast. Since the timing of an individual utility's system demand may be different from the timing of MISO's

[13] For example, if, on average, monthly demand in February in 75 percent of an annual peak of 1,000 MW, then demand in February would be 750 MW.

coincident peak demand, MISO refers to this approach of determining an individual utility's peak demand as its non-coincident peak (NCP) within MISO. A second approach for determining an individual utility's peak demand estimates the individual utility's peak demand at the time of MISO's coincident peak. MISO refers to this approach as the coincident peak (CP) method.

MISO is responsible for maintaining the reliability of the bulk transmission system, but states are responsible for ensuring that utilities within their jurisdiction have adequate generation and demand-response resources. Thus, given the recent change in MISO's policies regarding transmission, it is important to assess whether state resource planning should be changed to reflect MISO's policy. Although the CP method has merit because it takes into account changes in how MISO views capacity, the Department believes that the Commission should approve resource plans that ensure that each utility has a reliable system. A planning protocol that assumes an individual utility will only be responsible for its portion of MISO's CP could result in that same utility having inadequate generation resources in the event that one or more of MISO's planning assumptions are violated.

IPL discussed its calculation of the MISO CP in Section 3, Appendix A of its filing and in its July 3, 2014 response to DOC Information Request No. 6. IPL is unique compared to other load-serving entities (LSEs) in Minnesota because its LSE (referred to as ALTW LSE) designation with MISO is split between IPL and the Central Iowa Power Cooperative (CIPCO). Each utility produces an independent forecast for their respective load at the time of the MISO CP peak, which are added together to forecast the ALTW LSE demand at the MISO CP. In this filing, IPL supports its portion of the ALTW LSE CP forecast.

For MISO's new construct, the Company estimated expected load on IPL's system during a MISO peak day by using a two-stage linear regression analysis, based on historical data over the period from 2005 to 2012 on the IPL system, and further calculations. The first stage involved using the difference in hourly peak temperature between when the IPL non-coincident peak and the MISO coincident peak occurred and a dummy variable indicating whether the CP and NCP occurred on a different day to estimate the IPL diversity factor on a MISO coincident peak. The second stage involved using temperature on the IPL NCP to estimate temperature in the IPL service territory on a MISO CP. The Company then calculated the difference between the estimated temperature value from stage 2 and the average temperature on the non-coincident peak on the historical IPL system. IPL placed this difference in temperature into the stage 1 equation to estimate the normal diversity factor on the IPL system. The result of this analysis is an estimated MISO peak day diversity factor for the IPL system of approximately 3.56 percent.

The Department reviewed IPL's MISO coincident peak calculation and is concerned with the calculation of the coincident peak. Specifically, the coincident peak weather calculation, based on the second regression equation, is theoretically flawed because the model attempts to estimate one set of weather data using another set of weather data. The regression results may appear to be reasonable, and produce an acceptable diversity factor calculation, but there is no guarantee that reasonable or acceptable results will be produced on a consistent basis, so the Department is concerned that the current approach could create issues in the future.

The method used by IPL appears to be based on a methodology suggested by MISO and is similar to methods used by other Minnesota LSEs. Given the theoretical concerns with this methodology, the long-term reliability of this method is questionable for the future. Further, it is possible that different, more theoretically and practically sound methods exist to estimate the Company's load on a MISO coincident peak. One such example uses a method similar to the Company's non-coincident peak forecast in this IRP filing but based on data representative of the MISO coincident peak. The limiting factor is that insufficient data currently exists to complete this analysis because MISO-specific data does not exist prior to 2005; however, the Department believes creation of a representative historical MISO data stream is possible.

Assuming a reasonable level of data retention by all MISO members, there should be sufficient historical, daily (or even hourly) data available to calculate a representative historical daily MISO system demand figures. This representative data stream would be constructed by aggregating historical load data and then finding the monthly dates (or hours) with the greatest demand. With data in this format, IPL would be able to forecast peak demand in the same manner that it forecasted its non-coincident peak in its IRP filing, with only minor changes to its weather data to correspond with the representative, historical MISO peak days (or hours).

The Department recommends that IPL provide a detailed discussion in its *Reply Comments* regarding whether it believes creation of a dataset representative of historical MISO conditions is possible, from IPL's perspective, and whether the Company would be amenable to participating in this type of analysis with MISO.

6. Conclusions and Recommendations

Based on the Department's review of IPL's energy sales and peak demand forecasts, the Department concludes that they are acceptable for planning purposes. The Department identified a concern regarding the Company's peak demand forecast; however, the impact on the demand forecast was *de minimus*.

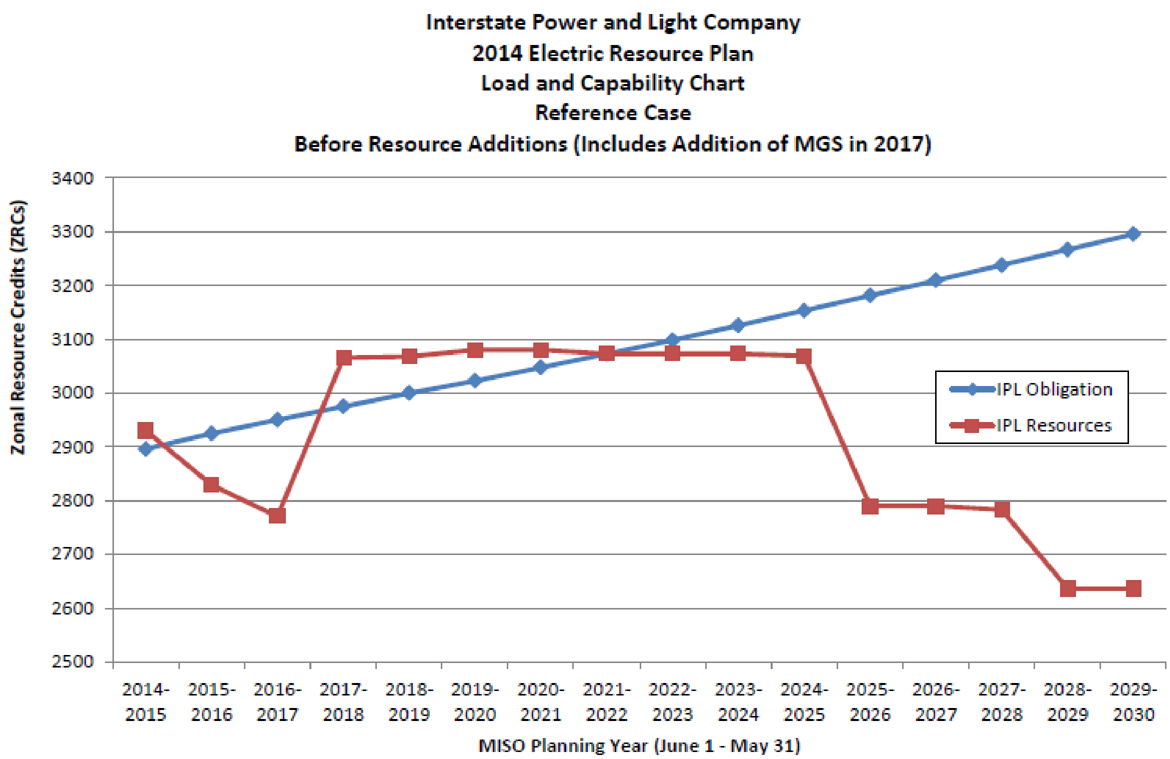
The Department also reviewed IPL's forecast of its projected demand on a MISO coincident peak. This IRP marks the first time that IPL has forecasted this value. It is important from a resource planning perspective to assess whether MISO's construct affects IPL's resource planning. Further, even if it were reasonable to plan resources based on MISO's peak rather than IPL's peak, based on its review of the Company's projection method, the Department identified issues with IPL's method of estimating load on its system during MISO's peak.

It is unclear if the issues with the MISO coincident peak are substantive, but the Department recommends that IPL continue to monitor the calculation of the coincident peak on a going forward basis. Along with this recommendation, the Department recommends that IPL provide, in *Reply Comments*, a detailed discussion regarding whether the Company believes creation of a dataset representative of historical MISO conditions is possible, from IPL's perspective, and whether the Company would be amendable to participating in this type of analysis with MISO.

C. RESOURCE NEEDS ASSESSMENT

One of the principal reasons for integrated resource planning is to ensure that a utility will have adequate resources to cover future demand in a cost-effective manner. IPL's resource needs as expressed in the Company's Load and Generation Chart is shown below:

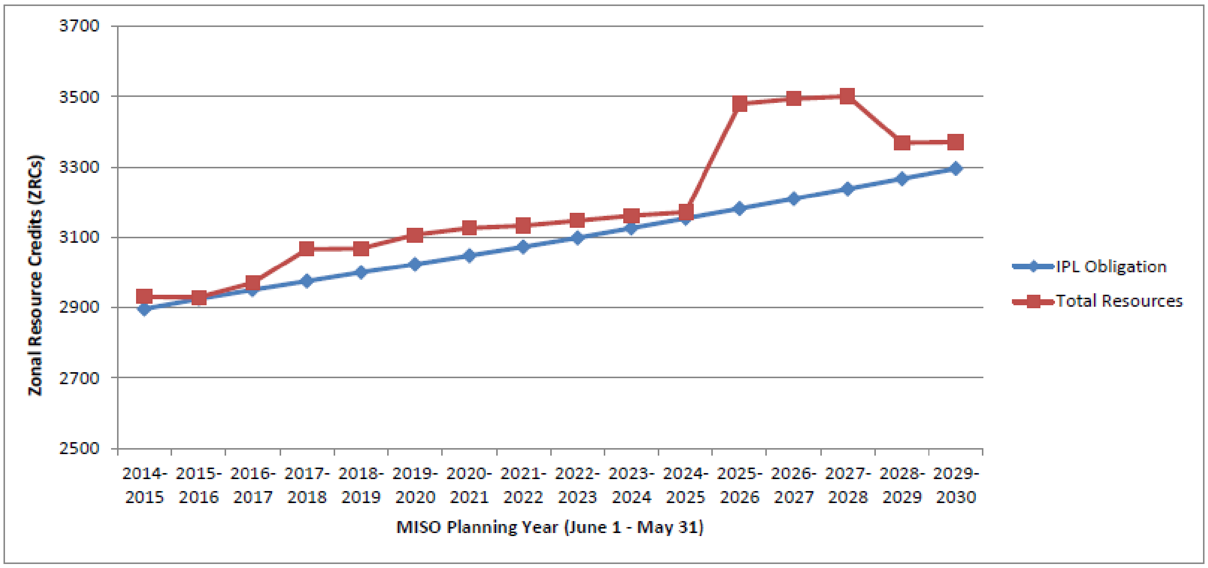
Figure 3:



As shown in Figure 3, IPL projected a near term deficit to be met through the short term purchase of capacity in 2015 and 2016 until the 650 MW Marshalltown Generating Station (MGS) Combined Cycle facility is placed in service in 2017. IPL then projects a surplus until 2022. IPL provided Chart 2 below to illustrate its expected resource additions compared to its expected obligation.

Figure 4:

Interstate Power and Light Company
2014 Electric Resource Plan
Load and Capability Chart
No Carbon Reference Case (Carbon Cases very similar)
After Resource Additions



IPL's projected resources, including its planned resource additions, are shown in Figure 4. The addition of incremental renewable generation, including satisfying the Minnesota Solar Energy Standard delays the expected deficit until 2024, when IPL expects to add 600 MW of combined cycle capacity.

D. DEMAND-SIDE RESOURCES

1. Introduction

One purpose of resource planning is to estimate the optimal amount of demand-side resources for meeting the Company's future needs. In the past, another factor used to assess the amount of DSM in a resource plan was whether it at least included the amount of energy and demand savings that would result from meeting the statutory spending requirements of the Conservation Improvement Program (CIP). The CIP statutes (Minn. Stat. §216B.2421) were changed in 2007; the statute now sets an annual energy savings goal of 1.5 percent of gross annual retail sales for each utility unless adjusted by the Commissioner.

In addition, Minn. Stat. §216B.2401 states:

> The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. The legislature further finds that cost-effective energy savings should be procured

> systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change.
>
> Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas through cost-effective energy conservation improvement programs and rate design, energy efficiency achieved by energy consumers without direct utility involvement, energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

In the Commission's Order accepting IPL's last IRP,[14] the Commission approved a 1.4 percent annual energy savings target for resource planning purposes.

In analyzing a utility's DSM plan within an IRP, the Department considers, along with other factors, the Company's:

1. historical CIP achievements,
2. annual and lifetime costs of different energy savings levels compared to the costs of supply-side resources, and
3. present value costs of different DSM scenarios across the IRP's planning period.

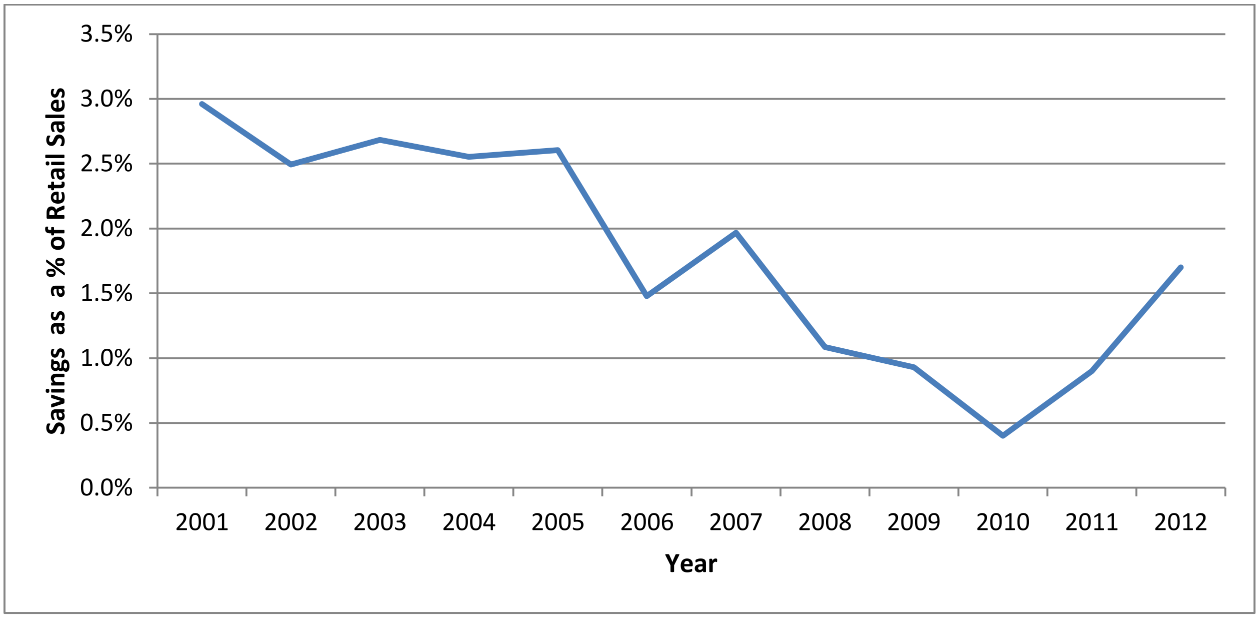
The Department evaluates the IRP's DSM levels with these three factors in the following sections.

2. IPL's Historical CIP Achievements

The Department considers a utility's historical DSM achievements in evaluating a utility's DSM proposal within the IRP. A utility's energy savings can be measured two ways: 1) by the energy saved in the year DSM measures are installed, and 2) by the total energy saved during the lifespan of the DSM measure. IPL has been filing Electric CIP filings with the Department since the early 1990s. Figure 5 below shows IPL's Minnesota first-year energy savings as a percent of retail sales 2001 to 2012.

[14] Docket No. E001/RP-08-673

Figure 5: IPL First-Year Energy Savings as a Percent of Retail Sales, 2001 - 2012[15]



In its annual CIP Status Reports, IPL files information on its annual energy savings and expenditures. IPL's CIP data for 2008 through 2012 is summarized in Table 2 below.

Table 2: IPL Energy Savings and Spending, 2008 – 2012

Year	Expenditures	Annual Credited Savings at the Generator (kWh)	Annual Savings Cost ($/kWh)	Percent Savings (CIP)	Lifetime savings (MWh) [16]	Lifetime Energy Cost ($/kWh)
2008	$2,161,420	9,698,759	$0.22	1.10%	133,843	0.016
2009	$2,213,008	8,648,648	$0.26	0.93%	119,351	0.019
2010	$1,267,734	3,461,129	$0.37	0.40%	47,764	0.027
2011	$1,720,282	7,685,049	$0.22	0.90%	106,054	0.016
2012	$2,548,149	14,365,499	$0.18	1.70%	198,244	0.013
Average	**$1,982,119**	**8,655,431**	**$0.25**	**1.0%**	**119,445**	**$ 0.018**

[15] 2001 - 2007 data from Department's Proposed CIP Decision in Docket No. E, G001/CIP-07-17.01; 2008 - 2012 data is from IPL's annual CIP status reports.
[16] In response to Department IR # 7, IPL stated that the weighted-average lifespan of DSM measures in the Base, Low, and Medium DSM Scenarios is 13.8 years; the High DSM Scenario assumes a 13.9 weighted-average lifespan. The Department applied the 13.8 year lifespan figure to the historical CIP energy savings and expenditures to estimate the average lifetime energy costs of DSM measures installed.

While analyzing historical energy savings data provides useful information on DSM average costs and what types of DSM programs a utility has pursued in the past, historical savings levels do not determine how much DSM a utility can and should procure in the future. As can be seen in Figure 5 and Table 2 above, IPL's energy savings fell dramatically in 2010, though savings increased in 2011 and 2012. Between 2001 and 2007, IPL was consistently achieving energy savings at or above 1.5%. Between 2008 and 2012, IPL's energy savings averaged 1.0% of annual retail sales.

3. DSM in Current IRP

IPL developed four Minnesota DSM scenarios for analysis in this IRP: low, base, medium, and high. The amount of energy and demand savings achieved in Iowa was held constant in each scenario. The base scenario assumed energy and demand savings equal to the Company's approved 2013-2015 Electric Conservation Improvement Plan.

The Company provided annual energy savings levels under each scenario in response to the Department's Information Request 10. The Company indicated that any changes to the DSM levels could be implemented in 2015 at the earliest. Table 3 below compares the four scenarios across their 2015 energy savings, budgets, and average costs. The Department did not evaluate the annual budgets IPL provided for each DSM scenario. CIP budget assumptions are evaluated by the Department's CIP team within each utility's CIP Triennial Plans.

Table 3: IPL's Four DSM Scenarios by Annual Savings and Budgets

Scenario	Low	Base	Medium	High
Savings Percent of Retail Sales	0.72%	1.44%	1.87%	2.87%
2015 Annual Savings at the Generator (kWh)	5,927,566	11,811,612	15,342,041	23,579,707
2015 Estimated Budget	$1,601,938	$ 3,019,614	$ 6,104,891	$13,576,506
$/first year kWh savings	$ 0.27	$ 0.26	$ 0.40	$ 0.58
$/lifetime kWh savings	$ 0.020	$ 0.019	$ 0.029	$ 0.041

Table 4 shows the cumulative DSM impacts by 2029 under the four scenarios.

Table 4: IPL's Cumulative DSM Impacts by 2029

Net Cumulative DSM by 2029	Low	Base	Medium	High
Energy Savings (MWh)	79,514	157,197	203,807	312,562
Demand Savings (MW)	16.4	29.9	38.0	56.9

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4. DSM Energy Saving Lifetime Costs

Comparing DSM lifetime costs to total system costs per kWh in the IRP allows parties to see the differences between these two types of energy resources. Table 5 compares IPL's four DSM scenario lifetime costs and IPL's total system cost per kWh, as modeled by the Department in Strategist. Though costs vary each year, for simplicity Table 5 focuses on two years: 2015, the first year any of the DSM scenarios could be implemented, and 2029, the last year of the planning period.

Table 5: DSM and System Costs per kWh, 2015 and 2029[17]

		2015 ($/kWh)	2029 ($/kWh)
DSM Scenarios	**Low**	$ 0.020	$ 0.020
	Base	$ 0.019	$ 0.022
	Medium	$ 0.029	$ 0.036
	High	$ 0.041	$ 0.053
Supply Side Modeling	**Average System Cost**	**[TRADE SECRET DATA HAS**	**BEEN EXCISED]**

The data in Table 5 demonstrates that the average cost per kWh saved in the Low, Base, and Medium DSM Scenarios are lower than the average system cost in 2015. By the end of the planning period in 2029, the average DSM cost is lower than the average system cost under all four scenarios. These results reflect the cost-effectiveness of DSM resources.

5. DSM Scenario Costs Across the Planning Period

Both IPL and the Department modeled the four DSM scenarios across the IRP planning period. This modeling included the energy and capacity savings, and assumed DSM budgets under the four scenarios. The IRP costs differences compared to the base case DSM level are listed in Table 6 below.[18]

Table 6: DSM Scenario Cost Differences, IPL and Department Modeling

Model	Low	Base	Medium	High
IPL Modeling	$ 28,624,000	-	$ 18,217,000	$ 14,085,000
Department Modeling (Strategist)	$ 69,491,284	-	$ 450,808	$ (569,317)

[17] DSM costs per kWh were estimated by dividing the annual DSM program costs in 2015 and 2029 provided by IPL in the IRP's Section 3, Appendix 3G by the lifetime savings of DSM measures installed in 2015 and 2029, respectively. DSM lifetime savings were estimated by multiplying the first year DSM energy savings, provided by IPL in response to the Department's IR 10, by the assumed weighted-average lifespan of DSM measures. The assumed DSM lifespan is 13.8 years for the base, low, and medium DSM scenarios. The High DSM scenario assumes 13.9 year lifespan. All dollar figures are in nominal dollars in the year the DSM projects are installed.

[18] The Department notes that IPL's modeling discounted costs to 2013 while, for technical reasons, the DOC's model discounted costs to 2008.

Under IPL's modeling, the base case DSM level provides the lowest cost plan since a positive figure indicates that costs would be higher if different levels of DSM were used. The Department's modeling, using Strategist, points to the high DSM level as being the most cost effective over the planning period.

The difference may arise from IPL's and the Department's different assumptions on natural gas CC and CT plants. IPL's base case includes a 605 MW natural gas CC plant coming online in 2025. Table 7 displays the difference in natural gas plants and power purchase agreements among IPL's expansion paths models under the four DSM scenarios. Table 7 only displays years 2025 through 2029 because the plans are the same in earlier years of the planning period.

Table 7: 2025-2029 DSM Scenario Expansion Paths (IPL Modeling)

Year	Low	Base	Medium	High
2025	605 MW CC	605 MW CC	100 MW PPA (1 year); 192 MW CT unit	100 MW PPA (1 year); 192 MW CT unit
2026			150 MW PPA (1 year)	100 MW PPA (1 year)
2027			150 MW PPA (1 year)	150 MW PPA (1 year)
2028			300 MW CC unit	300 MW CC unit
2029			50 MW PPA (1 year)	

The Department's modeling of the DSM base plan calls for three, 192 MW CT plants coming online every 2 years beginning in 2025. Table 8 shows the differences in expansion paths for the years 2025 through 2029 under the Department's modeling.

Table 8: 2025-2029 DSM Scenario Expansion Paths (Department Modeling)

Year	Low	Base	Medium	High
2025	192 MW CT	192 MW CT	192 MW CT	192 MW CT
2026	192 MW CT			
2027		192 MW CT		
2028	192 MW CT		192 MW CT	192 MW CT
2029		192 MW CT	192 MW CT	

The High Scenario delays the third CT unit beyond the end of the planning period, which is likely why the High Scenario is the least cost DSM scenario under the Department's modeling (see Table 6). However, deferring a CT plant a year or so beyond the planning period does not eliminate costs; rather the costs are pushed beyond the scope of the IRP plan. In addition, as seen in Table 6, the cost difference in the Department's modeling between the Base, Medium, and High DSM scenarios is small, and can be considered within the margin of error of the model.

6. *Department Recommendations*

Based on our analysis, the Department recommends that the Commission approve IPL's proposed amount of DSM, which on an annual basis averages 1.44 percent of IPL's retail sales. The Department makes this recommendation for the following reasons:

1. While IPL's annual energy savings have increased since 2010, the Company has not consistently achieved the CIP 1.5 percent goal over the past 5 years. IPL's proposed 1.44 percent goal for IRP purposes appears to be a realistic goal to get IPL's annual savings closer to the CIP 1.5 percent target.

2. The 1.44 percent base plan provides the lowest DSM lifetime cost per kWh in 2015, and near the lowest cost at the end of the planning period in 2029.

3. The differences between the low and base DSM scenario expansion paths are small and occur in the last years of the IRP planning period (*see Table 8*). Thus, the Commission could approve the base 1.44 percent energy savings amount without concern that IPL could face a reliability problem if the Company did not achieve the energy savings over the long term.

E. IPL'S EGEAS MODELING

1. *Previous Resource Plan*

Regarding modeling, the Commission's March 2, 2012 *Order Approving Resource Plan with Modifications, Requiring Baseload Diversification Study and Additional Filings, and Setting Date for Next Resource Plan* in IPL's most recent IRP proceeding (Docket No. E001/RP-08-673) required IPL to:

- include in its base case a CO_2 cost at the mid-point of the Commission-approved range for subsequent resource plans;
- justify its assumptions regarding heat rates and availability over time at its generating units, with a specific emphasis on the operational performance of its Tier 2 coal units;
- run contingencies on coal prices of +30 percent, +20 percent, +10 percent, and -10 percent on the base assumptions;
- run contingencies for a broad range of natural gas prices; and
- incorporate its demand response study and include the potential for demand response capacity savings in Minnesota within its scenario analyses.

Regarding these requirements IPL:

- included in one of its three base cases a 2017 CO_2 cost of $21.40;
- explained its heat rate and availability assumptions in section 6.10 of the Petition;
- ran the coal contingencies (see sections 6.5g and 6.5h of the Petition) specified by the Commission;

- ran natural gas contingencies (see sections 6.5e and 6.5f of the Petition); and
- ran several Minnesota demand response capacity savings scenarios (see section 6.5v of the Petition).

Regarding modeling, the Commission's May 13, 2013 *Order Finding Baseload Diversification Study in Compliance with 2012 Resource Plan Order, Setting Date for Next Resource Plan, and Setting Further Requirements* in IPL's baseload diversification study (Docket No. E001/RP-08-673) asked the Company to consider the following in its analysis:

- limiting the amount of energy it draws from the spot market each year to five, and at most ten percent;
- use of the midpoint of the Commission-approved CO_2 regulatory costs in the Company's base case;
- use of the Commission-approved externality values in the Company's base case; and
- evaluation of the impact of lower and higher wind prices on the Company's expansion plan.

Regarding these requests, IPL:

- reduced its reliance on the wholesale energy market to below 5 percent starting in 2017;
- included in one of the three base cases a 2017 CO_2 cost of $21.40;
- used the Commission's externality values at the mid-point in one of the three base cases along with the high and low values (see sections 6.5o and 6.5p of the Petition); and
- ran several wind price scenarios (see sections 6.5k and 6.5l of the Petition).

2. *Analysis of IPL's Modeling Tool*

As noted above, IPL used EGEAS software in the instant IRP. EGEAS is a software package developed by the Electric Power Research Institute (EPRI), which uses inputs such as fuel costs, energy and demand forecasts, capital costs of alternatives, heat rates, discount rates, inflation rates, and so on to determine the least cost expansion plan for a particular utility. EGEAS simulates a utility's system year by year and attempts to determine the least cost expansion path by testing all possible combinations of the available alternatives to meet the capacity and energy deficits and then ranking the resulting plans.

EGEAS is a standard capacity expansion model that is used by other utilities in Minnesota, such as Southern Minnesota Municipal Power Agency, and by MISO. In addition, EPRI states that EGEAS has been used for resource planning purposes by several utilities around the country; for example, EGEAS is the modeling tool that was used by Northern States Power Company d/b/a Xcel Energy in previous IRPs. Based upon our review, the Department concludes that EGEAS is a reasonable modeling tool since EGEAS allows a side-by-side comparison of resource alternatives to fill IPL's resource needs. That is, EGEAS allows IPL to determine the optimal size, type, and timing of the Company's long-term resource needs.

3. Constructing an Initial Case

The Department used Strategist to review the results of IPL's modeling efforts. To construct a Strategist initial case to compare to IPL's EGEAS base case for the "MN Midpoint 2017 Carbon Scenario" (Minnesota Base Case) the Department used data provided by IPL in:

- the Petition; and
- on a CD accompanying the Petition.

The Department's initial case used the forecast, generating unit, and other general inputs obtained from IPL in order to mimic IPL's Minnesota Base Case.[19] The Department required Strategist to add the following expansion units, which were included in IPL's Minnesota Base Case:

- two 50 MW capacity only purchases in 2015;
- four 50 MW capacity only purchases in 2016;
- the Marshalltown combined cycle unit in 2017;
- a 100 MW wind unit annually from 2018 through 2028;
- a 10 MW solar unit in 2020; and
- a 605 MW combined cycle unit in 2025.

When the Department ran its matching case in Strategist, the Department also made available to Strategist optional expansion units that the model could have chosen to address any unmet capacity needs during the planning period. Specifically, generic peaking units, intermediate units, and a 1-year capacity only purchase were available to be selected. However, in the matching case IPL has sufficient resources to meet reserve requirements throughout the planning period (2014 to 2029). Therefore, since the Department did not allow the model to select "superfluous" units, no other expansion units were examined by Strategist.[20]

After constructing the initial case the Department compared the Strategist outputs to the EGEAS outputs provided by the Company.[21] The Department notes, first, that the overall present value of revenue requirements (PVRR) for the study period reported by Strategist ($11.24 billion) was significantly different from the PVRR reported by EGEAS ($17.64 billion).[22] The difference was attributable to both the planning period ($6.76 billion Strategist cost vs. $10.05 billion EGEAS) and the end effects period ($3.58 billion Strategist cost vs. $7.59 billion EGEAS).

[19] The EGEAS data used in constructing the initial case was taken from the file "c001_edit.out" which was included on the CD accompanying the Petition.

[20] Normally Strategist checks expansion units only if required reserve criteria are not met. However, when superfluous units are allowed Strategist will check to see whether it is cost effective to add an expansion unit even though the unit is not needed to meet required reserve criteria.

[21] All EGEAS data used in the comparison was taken from the files "c001_report.out" and "c001_edit.out" which were included on the CD accompanying the Petition.

[22] Note that the study period equals the planning period (here 2014 to 2029) plus the end effects period.

Second, Strategist's annual total costs were also different from EGEAS starting in 2017 (when IPL's new Marshalltown combined cycle unit is expected to come on line). For the years 2010 to 2024, the differences range from the Strategist costs being 16 percent lower to 27 percent lower than those in EGEAS. The Department reviewed the output data to discover why the percent difference appears from 2017 on. The largest source of difference was in fuel costs and variable operations and maintenance costs. Thus, the Department focused on getting the units to dispatch in the correct order—demonstrating that the relative costs of the unit were correct, even if the absolute value of the costs in Strategist was too low.[23] The Department ranked each generating unit on IPL's system based upon its variable costs in Strategist and EGEAS for each year of operation. The results show that about 95 percent of the time a generating unit has the same rank or is different by only one place in the dispatch order. This result is shown in Table 9 below.

Table 9: Generating Unit Dispatch Order Rank (Strategist vs. EGEAS)

Criteria	Count	Percent of Total	Running Percentage
same rank	295	76.4%	76.4%
off by 1	73	18.9%	95.3%
off by 2	15	3.9%	99.2%
off by 3	2	0.5%	99.7%
off by 4	-	0.0%	99.7%
off by 5	-	0.0%	99.7%
off by 6	1	0.3%	100.0%
TOTAL	386	100.0%	100.0%

Given that the relative dispatch rank of the units was similar, the Department concluded that the initial case model was reasonably similar to that of IPL's EGEAS model. Therefore, the Department proceeded to the next step, establishing a Strategist base case.

4. Establishing a Base Case

Having established an initial case that could produce results reasonably similar to that of IPL, in terms of unit dispatch, the Department then proceeded to modify the initial case to examine the effects of different options and scenarios.[24] First, the Department added a generic coal unit;[25] since IPL's base case does not add a coal unit it was not necessary to

[23] While clearly it would be preferable to get the absolute level of costs correct, the analysis necessary to accomplish that goal would be very time intensive, potentially requiring delays to the resource plan. Thus, the Department compromised by getting the relative costs correct.

[24] Note that to the extent the absolute level of costs are too low, that means new units added to IPL's system have avoided cost benefits that are too low. Thus, the Strategist model potentially is biased against adding expansion units.

[25] Since the United States District Court, District of Minnesota enjoined the Public Utilities Commission from enforcing Minn. Stat. § 216H.03, subd. 3(2)–(3), the Department added a generic coal unit as an expansion option to examine this result. See the *Memorandum Opinion and Order* in case no. 11-cv-3232 (SRN/SER).

develop a generic coal unit for the matching case. To obtain economies of scale while keeping the unit size reasonable for IPL's system, the Department modeled the coal unit as a 300 MW share of a larger, 600 MW unit.

Second, the Department updated the pricing for the 10 MW solar unit forced into IPL's expansion plan in order to meet the Minnesota Solar Energy Standard. Previously the unit had both a variable cost and capacity cost component, to mimic the approach used by IPL. However, the Department revised the unit to have a flat $100 per MWh cost so that the price would be easier to understand.

Third, the Department updated the pricing for the 200 MW wind units available every other year. The Department's wind prices are based on a cost of $45 per MWh in 2014, inflated at 2 percent per year to get the price for a fixed, 20 year power purchase agreement (PPA). For example, the wind available in 2015 has a cost of $45.90 per MWh for each year of a 20 year PPA term, the wind available in 2017 has a cost of $47.75 per MWh for each year of a 20 year PPA term, and so forth.[26] Again, this was done so that the price would be easier to communicate, to be consistent with Department modeling in other dockets, and to reflect recent prices for wind projects.

Fourth, the Department allowed Strategist to select superfluous units for all types of resources—peaking, intermediate, baseload, and wind. A unit is superfluous when it is not needed to meet the required reserve ratio. Thus, the unit is added purely due to its economic impact.

The Strategist expansion plan for the Department's base case resulting from this analysis is shown in Table 10:

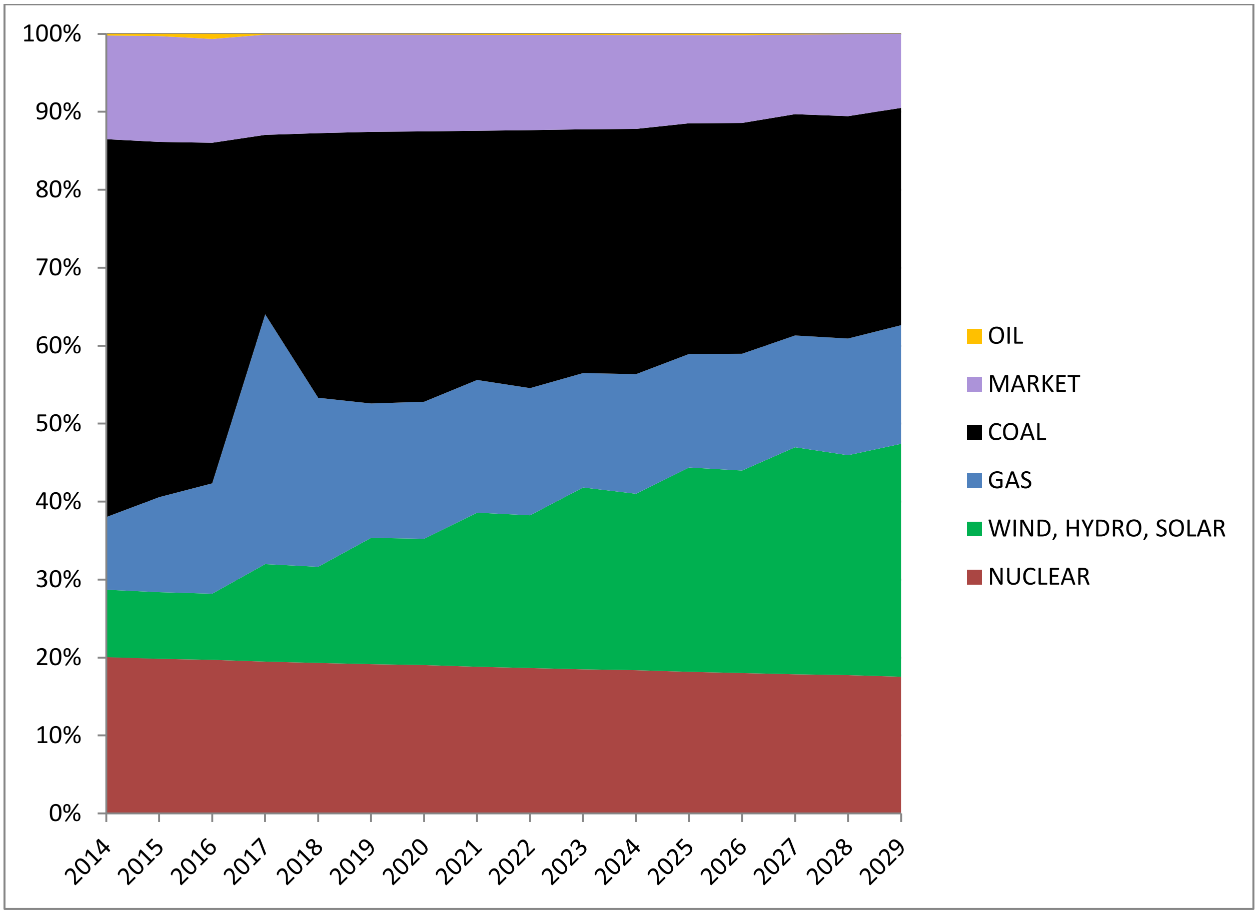
[26] Note that use of a PPA structure does not mean that the Department opposes company-owned wind projects. The Department supports the overall least cost wind project. Instead, the PPA structure was chosen as a model for its ease in communicating the price of the wind projects in question.

Table 10: Department Base Case Expansion Plan (units added)

Size:	CT 191.7 MW	CC 604.7 MW	WIND 100 MW	PPA 50 MW	SOLAR 10 MW	COAL 300 MW
2014	-	-	-	-	-	-
2015	-	-	-	1	-	-
2016	-	-	-	3	-	-
2017	-	-	2	-	-	-
2018	-	-	-	-	-	-
2019	-	-	2	-	-	-
2020	-	-	-	-	1	-
2021	-	-	2	-	-	-
2022	-	-	-	-	-	-
2023	-	-	2	-	-	-
2024	-	-	-	-	-	-
2025	1	-	2	-	-	-
2026	-	-	-	-	-	-
2027	1	-	2	-	-	-
2028	-	-	-	-	-	-
2029	1	-	2	-	-	-

The solar unit was added for purposes of meeting the state of Minnesota's solar energy standard. The addition of several wind units raises the percentage of energy from renewable resources on IPL's system from 8.6 percent in 2014 to 29.9 percent in 2029. Similarly, the addition of natural gas units, combined with the shutdown of some coal units, raises the percentage of energy from natural gas from 9.3 percent in 2010 to 15.2 percent in 2025. These increases are offset by decreases in energy from nuclear resources (falling from 20.1 percent to 17.5 percent), the market (falling from 13.3 percent to 9.5 percent) and coal resources (falling from 48.5 percent to 27.9 percent). These results are illustrated in Figure 6 below.

Figure 6: IPL's Fuel Mix



5. *Contingencies Examined*

Having established the base case, the Department next determined the contingency cases to be reviewed in each scenario. The Department ultimately decided to analyze the following contingencies:

1. High and low capital costs;
2. \$9 and \$34 per ton CO_2 cost;
3. CO_2 ramp down;
4. Coal costs high and low (±25 percent);
5. Low externalities;
6. High and low forecast;
7. High and low market prices (±25 percent);
8. Natural gas prices minus \$0.50 and \$1;
9. Natural gas prices increased in 50 cent increments from \$0.50 to \$2.00;
10. Solar prices higher and lower (using \$15 per MWh increments from \$70 to \$145 per MWh—\$100 is the base price);

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11. Wind prices higher and lower (using $5 per MWh increments from $30 to $60 per MWh—$45 is the base price);
12. Wind capacity credit higher and lower (±25 percent); and
13. Required reserve ratio higher and lower (±1 and 2 percent).

Thus there are a total of 36 contingencies in each scenario analyzed (a base plan plus the above 35 contingencies).

6. Scenarios Examined and Modeling Results

For this resource plan the Department examined nine different scenarios:

1. base case;
2. no wind expansion units;
3. no solar mandate;
4. no wholesale market;
5. no CO_2 internal cost or Commission externalities;
6. ramp down CO_2 per regulation by the Environmental Protection Agency (EPA);
7. low DSM;
8. medium DSM; and
9. high DSM.

Regarding Scenario 1 (base case), all of the contingencies add the same amount of wind at the same times (200 MW every other year). The contingencies also clearly express a preference for CT units (peaking plants) over CC units. The quantity of CT units added varies among scenarios that present different capacity needs.[27]

Regarding Scenario 2 (no wind expansion), the main impact is that the CT units are generally replaced by a CC unit in the expansion plan. In the base case for Scenario 2 the CC unit is added in 2025. The only time that a CC unit and CT units (2 of them) were selected was in the high forecast contingency. The only time that CT units were selected instead of a CC unit was in the low forecast (2 CT units), the +1 percent (4 CT units) and +2 percent (4 CT units) contingencies.

These results for Scenario 2 indicate that IPL's system is generally short of reasonably priced energy. Thus, when no wind units are available to provide new energy resources the CC unit is added.

Regarding Scenario 3 (no solar expansion), overall the results were not stable. For example, while the loss of the solar unit raises cost in the base case, such loss reduces costs in both the high and low forecast contingencies, both lower reserve ratios, both higher and lower wind capacity credits, and one of the 2 higher reserve ratio contingencies. Thus, the small solar unit's benefit is highly dependent upon the specific capacity needs, as the base case

[27] Specifically, fewer CT units are selected in the low forecast, lower reserve ratio, and high wind capacity credit contingencies, each of which requires less capacity from the non-wind additions. More CT units are selected in the high forecast contingencies.

was structured and any change to that capacity need changes the cost effectiveness of the solar unit. In terms of the base case for Scenario 3, there is no impact of the loss of solar expansions on the overall expansion plan, in terms of the total number of units added. However, in the base case the elimination of the solar unit forces the 2027 and 2029 CT units to be moved forward one year. This capacity benefit offsets the solar unit's high energy costs and causes the loss of the solar unit to raise system costs. The lesson from this scenario is that a small capacity-only purchase (without the penalty of the solar unit's high energy costs) would be cost effective.

Regarding Scenario 4 (no market), there is no impact on the overall expansion plan of allowing no market purchases. For Scenario 5 (no CO_2/externalities costs), there is no impact on the choice of CT/CC units. However, the loss of the CO_2 internal cost and externalities costs causes Strategist to select less wind at the higher cost levels; the trigger being a price of $55 per MWh. At $55 per MWh the wind units that are dropped are the 2017 and 2027 additions. At $60 per MWh the wind units that are dropped are the 2017, 2021, and 2023 additions.

Regarding Scenario 6 (CO_2 ramp down), it was not immediately clear how best to model EPA's CO_2 regulation goals as presented in recent draft regulations. However, given the limited information available at this time, and given that IPL gets almost 30 percent of energy from CO_2 free sources (largely wind and nuclear), it is possible that IPL's emissions of CO_2 from the base case may meet a calculation of the EPA goal and a separate scenario would not be necessary. Therefore, the Department did not run the scenario at this time. In the base case the carbon free sources grow to 35 percent by 2020 and 45 percent by 2028 because 200 MW of wind are added every other year and the nuclear unit (Duane Arnold Energy Center) continues to operate, while coal, diesel and gas boiler units are retired.

Scenarios 7 (Low DSM), 8 (Medium DSM), and 9 (High DSM) are discussed in the DSM section of these comments. Selected results from the scenarios run by the Department are available in Attachment A to these comments. However, the differences in the expansion plan for either the High DSM or Medium DSM scenarios do not appear until 2027 when a CT unit is deferred. Thus, regardless of DSM plan recommended, the near term action plan is the same.

7. Preferred Case

The Department's proposed near term action plan for IPL is as follows:

- use of short term power purchase agreements to cover capacity deficits until IPL's new Marshalltown CC unit comes on-line in 2017;
- acquiring approximately 100 MW of wind resources annually, starting in about 2017; and
- acquiring solar resources required by the Minnesota Solar Energy Standard by 2020.

For IPL's long term capacity needs, there are several years before a decision would need to be made. Therefore, the Department recommends that IPL continue to analyze the size, type, and timing of the Company's needs in the mid to late 2020s.

F. FIRM GAS

The Department also reviewed which of the Company's natural gas fueled units have firm natural gas service and which units have interruptible natural gas service. The relevant information was provided by IPL in the Company's response to Department Information Request No. 1. Additional information is available in Appendix 6M of the Petition which explains how IPL tiered winter reliability by unit.

Appendix 6M shows that during winter IPL will have to **[TRADE SECRET DATA HAS BEEN EXCISED]**

Regarding the summer season, IPL states in Appendix 6 M that **[TRADE SECRET DATA HAS BEEN EXCISED]**

Based upon this data the Department concludes that IPL's plans regarding firm natural gas appear to be reasonable based on the information available at this time.

G. COMPLIANCE WITH THE RENEWABLE ENERGY OBJECTIVE

1. Background

Prior to the 2007 Legislative Session, Minn. Stat. §216B.1691 required utilities to make a good faith effort to obtain 15 percent of their Minnesota retail sales from eligible energy technologies by 2015, and to obtain 0.5 percent renewable energy from biomass technologies. The 2007 Minnesota Legislature amended Minn. Stat. §216B.1691 to include a Renewable Energy Standard (RES) beginning in 2010. As amended, Minn. Stat. §216B.1691, Subd. 2 sets forth the Renewable Energy Objective in place through 2010 and requires that:

> Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers or the retail customers of a distribution utility to which the electric utility provides wholesale electric service so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies, and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Minn. Stat. §216B.1691, Subd 2a establishes the Renewable Energy Standard utilities must meet through 2025 and specifically requires that:

> …each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:
>
> - 2012 12 percent
> - 2016 17 percent
> - 2020 20 percent
> - 2025 25 percent

The statute no longer requires that a portion of the renewable energy generation come from biomass technologies. An eligible energy technology is defined by Minn. Stat. §216B.1691, Subd. 1 as an energy technology that:

> Generates electricity from the following energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minn. Stat. §216B.1691, subd. 2(d) directs the Commission to "issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort."

The Commission set forth the criteria for determining compliance with the RES Statute after taking comments from affected parties in a number of Orders.[28] Among the resources the Commission has determined to be ineligible for meeting the RES are resources used for green pricing, resources that do not meet the statutory definition of eligibility, and generation assigned to compliance for other regulatory purposes such as another state's Renewable Portfolio Standard Requirements (RPS).

The 2007 amendment to Minn. Stat. §216B.1691, subd. 4 required the Commission to establish a program for tradable Renewable Energy Credits (RECs) by January 2008, and to require all electric utilities to participate in a Commission-approved REC tracking system once such a system was in operation.

The Commission subsequently adopted the use of the Midwest Renewable Energy Tracking System (M-RETS), a multi-state REC tracking system, as the REC tracking system under Minn. Stat. §216B.1691, Subd. 4(d), and required Minnesota utilities to participate.[29] Specifically, the Commission required utilities to complete the online registration process and sign the Terms of Use agreement with the M-RETS system administrator APX, Inc., and receive account approval from APX by January 1, 2008. In addition, the Commission directed utilities to make a substantial and good faith effort to create a system account and sub-accounts for its organization, and to register its generation units/facilities in the M-RETS system by March 1, 2008.

In its December 18, 2007 *Order Establishing Initial Protocols for Trading Renewable Energy Credits,* the Commission adopted a four-year shelf life for all renewable energy credits to be used for compliance with the Minnesota RES. A four-year shelf life allows a REC to be retired towards MN RES compliance in the year of generation and during the four years following the year of generation.

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[28] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities. (June 1, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869; *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits and Requesting Periodic Updates from Stakeholder Group; (October 19, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869, Order After Reconsideration (August 13, 2004)
[29] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. §216B.1691, Subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9, 2007)

Finally, in its December 3, 2008 *Third Order Detailing Criteria and Standards for Determining Compliance under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits*, the Commission directed utilities to begin retiring RECs equivalent to one percent of their Minnesota annual retail sales for the 2008 and 2009 compliance year by May 1st of the following year. Upon retirement, RECs are transferred into a specific Minnesota RES retirement account and, once retired, are not available to meet other state or program requirements, thus addressing the statutory prohibition against double counting the RECs and promoting the environmental benefits of renewable energy. The Commission further directed the utilities to submit a compliance filing demonstrating their compliance with the RES by June 1st

In addition to amending the RES Statute, Minn. Stat. §216B.241, Subd. 1c(b) was added to establish an energy-savings goal as part of a utility's conservation improvement plan (CIP), and states:

> Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

The attainment of the 1.5 percent energy savings goal will reduce a utility's forecasted retail sales, and consequently lower the amount of renewable generation required to meet RES obligations.

2. IPL's Renewable Energy Obligation

Table 11 below summarizes IPL's RES requirement in MWh's over the forecast period. IPL's forecasted retail sales reflect compliance with the energy-savings goals set forth under Minn. Stat. §216B.241.

 PUBLIC DOCUMENT

Table 11: IPL's Renewable Energy Objective

Year	MN Retail Sales	REO/RES Percentage	RES Requirement (MWhs)
2013	857,965	12%	102,956
2014	844,090	12%	101,291
2015	842,746	12%	101,130
2016	841,969	17%	143,135
2017	840,810	17%	142,938
2018	839,995	17%	142,799
2019	846,837	17%	143,962
2020	854,304	20%	170,861
2021	861,834	20%	172,367
2022	869,440	20%	173,888
2023	877,126	20%	175,425
2024	884,881	20%	176,976
2025	892,705	25%	223,179
2026	900,597	25%	225,149
2027	908,559	25%	227,140
2028	916,592	25%	229,148
2029	924,696	25%	231,174

Over the forecast period, IPL's RES requirement increases from 102,956 MWhs in 2013 to 231,174 MWhs in 2028.

3. *Renewable Generation Resources*

a. Existing Resources

IPL currently has annual renewable generation of approximately 1,400,000 MWh system wide. The Company allocates RECs from its renewable facilities acquired through PPAs on the basis of the state's relative percentage of system sales, or approximately 5.2 percent for Minnesota. RECs from Whispering Willow East, IPL's only utility-owned facility, are allocated on the basis of system coincident peak in keeping with its cost allocation between jurisdictions which allocates approximately 6.2 percent for Minnesota. For 2013, Minnesota's share of IPL's total renewable generation was 80,460 RECs.

In addition to current year renewable generation, IPL currently has unretired REC balances allocated to Minnesota in M-RETS of approximately 11,000 RECs. Given the existing allocation of RECs and without adding new renewable resources, IPL expects to fall short of Minnesota's RES requirements as follows:

- 23,000 RECs per year for 2013-2015 (12% RES requirement)
- 67,000 RECs per year for 2016-2019 (17% RES requirement)
- 103,000 RECs per year for 2020-2024 (20% RES requirement)
- Over 150,000 RECs per year for 2025-2029 (25% REC requirement)

In contrast to Minnesota's expected shortfall in RECs, IPL has an abundance of unretired RECs allocated to Iowa. The Company has an unretired REC balance of approximately 1.3 million RECs allocated to Iowa compared with an estimated Iowa RES requirement of 117,833 RECs per year. The Company expects to meet its short-term Minnesota RES requirements through the purchase of RECs from Iowa. IPL requested Commission approval for the recovery of the purchase costs through its RES Rider for 24,000 RECs in 2012, and an additional 40,000 RECs from Iowa in Docket No. E001/M-12-950. The Commission granted IPL's request in its Order dated July 28, 2014.

b. Compliance with 2013 RES

IPL submitted its 2013 Annual RES compliance report in Docket No. E999/PR-14-12. The Company reported that it had 857,177 MWh in Minnesota retail sales, and 788 MWh in wholesale sales to the Minnesota community of Dundee for a total of 857,965 MWh. IPL reported that it retired 102,956 or 12 percent of its Minnesota retail sales to comply with its 2013 RES requirement.

c. Future Compliance with RES

Table 12 below, estimates IPL's RES compliance with its planned additions. The column labeled "Cumulative RES Surplus/Need" reflects the ability of the utility to carry-forward unretired RECs for future year's compliance.

Table 12: IPL Estimated RES Compliance

Year	REO/RES Requirement MWh	Annual Generation MN Share	MN Share Cumulative Planned Additions (MWhs)	Cumulative RES Surplus/ (Need) (Prev Yr Bal. –RES Req. +Add)
2013	102,956	80,460		
2014	101,291	78,536	40,000 (IA purchase)	29,128
2015	101,130	78,024		6,373
2016	143,135	77,432		(16,732)
2017	142,938	76,306		(82,435)
2018	142,799	75,545		(149,067)
2019	143,962	74,737	18,221	(198,100)
2020	170,861	72,320	36,442	(230,884)
2021	172,367	72,159	54,662	(274,762)
2022	173,888	70,388	72,883	(302,087)
2023	175,425	70,374	91,104	(314,483)
2024	176,976	68,023	109,325	(310,209)
2025	223,179	65,756	127,546	(291,617)
2026	225,149	65,741	145,766	(303,270)
2027	227,140	64,305	163,987	(298,691)
2028	229,148	55,118	182,208	(279,318)
2029	231,174	38,979	200,429	(252,919)

As noted above, IPL has significant wind resources that are currently allocated to Iowa. IPL has current annual renewable generation of approximately 1,400,000 MWh, far in excess of its estimated Iowa RES annual requirement of 117,833 MWh. In addition, the Company has an unretired REC balance of approximately 1,300,000 MWh. Consequently, IPL has sufficient resources to meet its RES requirement throughout its planning period.

d. Solar Energy Standard

As noted above, Minn. Stat. §216B.1691, Subd. 2(f) established a solar energy standard (SES). Specifically, the statute requires public utilities to generate or obtain at least 1.5 percent of their electric sales to retail customers from solar energy by the end of 2020, and requires that at least ten percent of the goal be met from distributed generation facilities with a nameplate capacity of 20 kW or less. The SES excludes retail electric sales to customers that are iron mining extraction and processing facilities, paper mills, wood products manufacturers, sawmills, or oriented strand board manufacturers.

IPL submitted its first annual report on its efforts to comply with the SES to the Commission in Docket No. E999/M-14-321. In 2013 the Company had 857,177 MWh of Minnesota retail sales, of which 10,978 MWh was to customers falling into the statutory definitions of excluded sales. IPL estimates it will need to acquire 7.5 MW of solar generation by 2020 (assuming a 20.4 percent capacity factor provided by the U.S. Energy Information Administration) in order to comply with the SES.

To date, the Company has approximately 73 kW of solar in the form of small distributed generation facilities in Minnesota. IPL's proposed IRP includes the addition of 10 MW of solar by 2020. The Company indicates it is in the process of assessing its opportunities to add solar to its system.

G. ENVIRONMENTAL ISSUES

The DOC generally reviews utility resource plans for compliance with pending state and national environmental legislation that impacts the electric utility's operations. IPL discussed environmental regulations impacting its electric utility operations in the Action Plan of its IRP

a. Sulfur Dioxide (SO_2), Nitrous Oxide (NO_x) and Particulate Matter (PM)

The Acid Rain Program, Clean Air Interstate Rule (CAIR), and the currently stayed Cross State Air Pollution Rule (CSAPR) all address reductions in SO_2, NO_x, and PM. The CSAPR was intended to replace CAIR; however, the CSAPR was stayed by the D.C. circuit court pending U.S. Supreme Court review. In April 2014, the Supreme Court issued its order upholding the CSAPR. A motion to lift the stay of the CSAPR is currently pending before the D.C. Circuit. In January 2014, the EPA stated its intent to propose a replacement for the CSAPR in October 2014.

IPL indicates that its plans currently comply with the emissions requirements under CAIR, including increased reductions under the Rule's Phase II set to begin in January 2015. In the event that either CSAPR is reinstated or a new rule proposed, the Company expects it will have sufficient opportunity to address any concerns, and to adjust its plans to implement new requirements.

b. Mercury

The Mercury and Air Toxics (MATS) rule was finalized in February 2012, and requires utilities to comply by 2015, unless granted a one-year extension. IPL indicates that its coal-fired generating facilities located in Iowa are subject to the MATS rules. The Company states that its current plans support compliance with the MATS rule.

c. Water Regulations

IPL included a review of the impact various Federal Clean Water Act requirements may have on its generation units. The Company indicates that it is reviewing thermal discharge rules as each of its facilities comes up for renewal of permits for pollutant discharge. Cooling Water Intake Structure Rules are intended to ensure that intake structures minimize harm to fish and other aquatic life. A final intake rule is expected to be issued in 2014, and IPL anticipates beginning field studies required by the rule in 2014.

d. Coal Combustion Residuals (CCR)

The EPA has issued a proposed rule for regulating the disposal of coal ash generated by coal combustion generation facilities. The proposed rule contemplates two possible regulatory options. The first option would create a special classification for coal ash that would subject its disposal to many of the regulatory requirements applicable to hazardous waste, but would not categorize it as hazardous waste. The second option would regulate coal ash disposal as a non-hazardous solid waste, and establish national minimum standards for its safe disposal. The final rule is expected to be issued in late 2014.

IPL states that its current plans include closing all ash ponds, and converting ash handling systems to dry ore recirculating ash systems.

e. Greenhouse Gases

IPL states that it has complied with the EPA's Greenhouse Gas Reporting requirements. The Company indicates that its proposed 650 MW natural gas-fired combined cycle Marshalltown Generating Station will comply with the EPA's New Source Performance Standards for CO_2 emissions, and that it has no plans to build any new coal-fired generation at this time.

In the time since the Company filed its IRP, the EPA has issued its Clean Power Plan rules for Greenhouse Gas Reduction at existing generation facilities. The Department requests that

IPL provide comments in reply on the impact the proposed rules may have on its generation facilities.

H. MINNESOTA GREENHOUSE GAS EMISSIONS REDUCTION GOAL

In 2013, the Minnesota Legislature passed amendments to Minnesota Statutes §216B.2422, subd. 4. The newly amended legislation now states (new language underlined):

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. <u>The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f</u>.

On August 5, 2013, the Commission issued a Notice of Information in Future Resource Plan Filings (Commission's Letter). The Commission Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.

IPL provided a discussion of its compliance with the greenhouse gas reduction goal in Section 8 of its comments. Table 8.3.1 of IPL's comments shows that under no carbon scenario, the Company expects that its carbon emissions will decline by 37 percent by 2029 when compared to 2005 emissions. However, IPL's analysis excluded market energy purchases. The Department is working with parties to see if it is possible to come to a consensus on how to best estimate these reductions.

The Department recommends that in Reply Comments IPL modify its analysis to include market economy purchases. In our discussions with other utilities, the Department recommended that each utility calculate its CO_2 emissions the following approach:

- Start with emissions from utility-owned generation;
- Add emissions from utility purchases; and

- Subtract CO_2 emissions from sales from utility-owned generation[30].

If the emissions from utility purchases is unknown, the Department recommended that utilities use the 2005 average emissions per MWh for the Midwest Reliability Organization (MRO) West region 2005 purchases. For 2015 and 2025 the Department recommends that IPL use either the most up to date emissions data for the MRO West region, or use a version of the method recommended by Xcel Energy in its May 27, 2014 comments in Docket No. ET6133 /RP-13-1165. The Department will discuss this issue further with IPL before the Company's reply comments are due.

III. DEPARTMENT RECOMMENDATIONS

A. FORECAST

The Department recommends that IPL continue to monitor the calculation of its MISO coincident peak on a going forward basis. Further, the Department recommends that IPL provide, in *Reply Comments*, a detailed discussion regarding whether the Company believes that creation of a dataset representative of historical MISO conditions is possible, from IPL's perspective, and whether the Company would be amendable to participating in this type of analysis with MISO.

B. MODELING

Based on our modeling the Department recommends that the Commission approve the following short-term action plan for IPL:

- use of short term power purchase agreements to cover capacity deficits until IPL's new Marshalltown CC unit comes on-line in 2017;
- acquiring approximately 100 MW of wind resources annually, starting in about 2017; and
- acquiring solar resources required by the Minnesota Solar Energy Standard by 2020.

For IPL's long term capacity needs, there are several years before a decision would need to be made. Therefore, the Department recommends that IPL continue to analyze the size, type, and timing of the Company's needs in the mid to late 2020s.

C. COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVE

The Department recommends the Commission find IPL in compliance with its 2014 RES obligations.

[30] In general, Otter Tail followed this methodology in its original IRP analysis.

D. DSM

The Department recommends that the Commission approve IPL's proposed amount of DSM, which on an annual basis averages 1.44 percent of IPL's retail sales.

E. ENVIRONMENTAL ISSUES

The Department recommends that the Commission find that IPL has monitored the important environmental regulations that will impact their resources and operations. The Department requests that IPL provide comments in reply on the impact the proposed new EPA carbon dioxide rules may have on its generation facilities.

F. GREENHOUSE GAS REDUCTION GOAL

In its Reply Comments, the Department recommends that the Company update its analysis of its progress towards meeting the State's greenhouse gas reduction goal by including market energy purchases in its analysis.

/lt

	PVSC ($ Million)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	$ 10,906	$ 11,873	$ 10,914	$ 11,351	$ 9,089	$ 10,976	$ 10,907	$ 10,906
Forecast Low	$ 10,098	$ 11,005	$ 10,096	$ 10,516	$ 8,421	$ 10,158	$ 10,103	$ 10,174
Forecast High	$ 11,733	$ 12,773	$ 11,732	$ 12,243	$ 9,767	$ 11,815	$ 11,732	$ 11,799
Reserve Ratio - 2%	$ 10,830	$ 11,828	$ 10,829	$ 11,307	$ 9,013	$ 10,894	$ 10,834	$ 10,899
Reserve Ratio - 1%	$ 10,830	$ 11,870	$ 10,829	$ 11,307	$ 9,013	$ 10,960	$ 10,834	$ 10,902
Reserve Ratio + 1%	$ 10,915	$ 11,896	$ 10,925	$ 11,356	$ 9,098	$ 10,987	$ 10,920	$ 10,986
Reserve Ratio + 2%	$ 10,930	$ 11,908	$ 10,928	$ 11,366	$ 9,113	$ 10,990	$ 10,935	$ 11,005
Wind Low Cap Cred (	$ 10,927	$ 11,873	$ 10,925	$ 11,362	$ 9,109	$ 10,987	$ 10,932	$ 10,990
Wind High Cap Cred	$ 10,834	$ 11,873	$ 10,832	$ 11,310	$ 9,017	$ 10,897	$ 10,834	$ 10,903
CO2 @ 9	$ 9,970	$ 10,715	$ 9,976	$ 10,306	$ 9,089	$ 10,031	$ 9,973	$ 9,978
CO2 @ $34	$ 11,706	$ 12,897	$ 11,714	$ 12,276	$ 9,089	$ 11,784	$ 11,704	$ 11,697
CO2 Reduction	$ 10,929	$ 12,237	$ 10,936	$ 11,361	$ 9,126	$ 10,998	$ 10,930	$ 10,929
Externalities Low	$ 10,824	$ 11,790	$ 10,831	$ 11,257	$ 9,089	$ 10,893	$ 10,824	$ 10,823
Wholesale Mkt Low (-	$ 10,620	$ 11,578	$ 10,628	$ 11,351	$ 8,880	$ 10,689	$ 10,621	$ 10,621
Wholesale Mkt High (	$ 11,102	$ 12,096	$ 11,109	$ 11,351	$ 9,262	$ 11,172	$ 11,102	$ 11,100
Coal Low (-25%)	$ 10,492	$ 11,410	$ 10,499	$ 10,900	$ 8,588	$ 10,559	$ 10,493	$ 10,493
Coal High (+ 25%)	$ 11,246	$ 12,250	$ 11,254	$ 11,722	$ 9,574	$ 11,317	$ 11,246	$ 11,244
Natural Gas - $1.00	$ 10,634	$ 11,481	$ 10,641	$ 10,975	$ 8,896	$ 10,699	$ 10,636	$ 10,638
Natural Gas - $0.50	$ 10,792	$ 11,700	$ 10,799	$ 11,179	$ 8,997	$ 10,859	$ 10,793	$ 10,794
Natural Gas + $0.50	$ 11,002	$ 12,025	$ 11,009	$ 11,502	$ 9,178	$ 11,073	$ 11,001	$ 10,999
Natural Gas + $1.00	$ 11,096	$ 12,177	$ 11,104	$ 11,654	$ 9,266	$ 11,170	$ 11,095	$ 11,091
Natural Gas + $1.50	$ 11,187	$ 12,325	$ 11,195	$ 11,803	$ 9,355	$ 11,263	$ 11,185	$ 11,179
Natural Gas + $2.00	$ 11,279	$ 12,474	$ 11,287	$ 11,952	$ 9,443	$ 11,357	$ 11,276	$ 11,269
Solar @ $70	$ 10,903	$ 11,870	$ 10,914	$ 11,348	$ 9,086	$ 10,973	$ 10,904	$ 10,903
Solar @ $85	$ 10,905	$ 11,871	$ 10,914	$ 11,349	$ 9,087	$ 10,974	$ 10,905	$ 10,904
Solar @ $115	$ 10,908	$ 11,875	$ 10,914	$ 11,352	$ 9,091	$ 10,977	$ 10,908	$ 10,907
Solar @ $130	$ 10,910	$ 11,876	$ 10,914	$ 11,354	$ 9,092	$ 10,979	$ 10,910	$ 10,909
Solar @ $145	$ 10,911	$ 11,878	$ 10,914	$ 11,356	$ 9,094	$ 10,981	$ 10,912	$ 10,911
Wind @ $30	$ 10,469	$ 11,873	$ 10,476	$ 10,913	$ 8,652	$ 10,538	$ 10,469	$ 10,468
Wind @ $35	$ 10,615	$ 11,873	$ 10,622	$ 11,059	$ 8,797	$ 10,684	$ 10,615	$ 10,614
Wind @ $40	$ 10,761	$ 11,873	$ 10,768	$ 11,205	$ 8,943	$ 10,830	$ 10,761	$ 10,760
Wind @ $50	$ 11,052	$ 11,873	$ 11,060	$ 11,497	$ 9,235	$ 11,122	$ 11,053	$ 11,052
Wind @ $55	$ 11,198	$ 11,873	$ 11,205	$ 11,643	$ 9,367	$ 11,268	$ 11,199	$ 11,198
Wind @ $60	$ 11,344	$ 11,873	$ 11,351	$ 11,788	$ 9,460	$ 11,413	$ 11,344	$ 11,343
Capital Cost Low	$ 10,828	$ 11,757	$ 10,832	$ 11,273	$ 9,011	$ 10,895	$ 10,830	$ 10,852
Capital Cost High	$ 10,985	$ 11,989	$ 10,995	$ 11,429	$ 9,167	$ 11,057	$ 10,983	$ 10,959

	PVSC Difference from Base Case, Same Contingency ($ Million)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	$ -	$ 967	$ 7	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Forecast Low	$ -	$ 907	$ (2)	$ 418	$ (1,677)	$ 60	$ 5	$ 76
Forecast High	$ -	$ 1,039	$ (1)	$ 510	$ (1,967)	$ 81	$ (1)	$ 66
Reserve Ratio - 2%	$ -	$ 998	$ (1)	$ 477	$ (1,817)	$ 64	$ 4	$ 69
Reserve Ratio - 1%	$ -	$ 1,040	$ (1)	$ 477	$ (1,817)	$ 130	$ 4	$ 72
Reserve Ratio + 1%	$ -	$ 981	$ 10	$ 440	$ (1,817)	$ 72	$ 5	$ 71
Reserve Ratio + 2%	$ -	$ 978	$ (2)	$ 436	$ (1,817)	$ 60	$ 5	$ 75
Wind Low Cap Cred (- 25%)	$ -	$ 947	$ (2)	$ 436	$ (1,817)	$ 60	$ 5	$ 64
Wind High Cap Cred (+ 25%)	$ -	$ 1,040	$ (1)	$ 477	$ (1,817)	$ 64	$ 1	$ 69
CO2 @ 9	$ -	$ 745	$ 6	$ 336	$ (881)	$ 61	$ 3	$ 8
CO2 @ $34	$ -	$ 1,191	$ 8	$ 571	$ (2,617)	$ 78	$ (2)	$ (9)
CO2 Reduction	$ -	$ 1,308	$ 7	$ 432	$ (1,803)	$ 69	$ 1	$ (0)
Externalities Low	$ -	$ 966	$ 7	$ 433	$ (1,735)	$ 69	$ 0	$ (0)
Wholesale Mkt Low (- 25%)	$ -	$ 958	$ 7	$ 731	$ (1,740)	$ 69	$ 1	$ 0
Wholesale Mkt High (+ 25%)	$ -	$ 994	$ 7	$ 249	$ (1,840)	$ 71	$ 0	$ (2)
Coal Low (-25%)	$ -	$ 918	$ 7	$ 408	$ (1,904)	$ 68	$ 1	$ 1
Coal High (+ 25%)	$ -	$ 1,004	$ 8	$ 476	$ (1,673)	$ 71	$ (0)	$ (2)
Natural Gas - $1.00	$ -	$ 847	$ 7	$ 341	$ (1,738)	$ 65	$ 2	$ 4
Natural Gas - $0.50	$ -	$ 907	$ 7	$ 387	$ (1,796)	$ 67	$ 1	$ 2
Natural Gas + $0.50	$ -	$ 1,023	$ 8	$ 501	$ (1,823)	$ 72	$ (0)	$ (3)
Natural Gas + $1.00	$ -	$ 1,080	$ 8	$ 558	$ (1,830)	$ 74	$ (1)	$ (5)
Natural Gas + $1.50	$ -	$ 1,138	$ 8	$ 616	$ (1,832)	$ 76	$ (2)	$ (7)
Natural Gas + $2.00	$ -	$ 1,196	$ 9	$ 673	$ (1,835)	$ 78	$ (2)	$ (10)
Solar @ $70	$ -	$ 967	$ 11	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Solar @ $85	$ -	$ 967	$ 9	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Solar @ $115	$ -	$ 967	$ 6	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Solar @ $130	$ -	$ 967	$ 4	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Solar @ $145	$ -	$ 967	$ 2	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Wind @ $30	$ -	$ 1,404	$ 7	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Wind @ $35	$ -	$ 1,258	$ 7	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Wind @ $40	$ -	$ 1,113	$ 7	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Wind @ $50	$ -	$ 821	$ 7	$ 444	$ (1,817)	$ 69	$ 0	$ (1)
Wind @ $55	$ -	$ 675	$ 7	$ 444	$ (1,831)	$ 69	$ 0	$ (1)
Wind @ $60	$ -	$ 529	$ 7	$ 444	$ (1,884)	$ 69	$ 0	$ (1)
Capital Cost Low	$ -	$ 929	$ 4	$ 444	$ (1,817)	$ 66	$ 2	$ 24
Capital Cost High	$ -	$ 1,005	$ 10	$ 444	$ (1,817)	$ 73	$ (1)	$ (25)

	PVSC Difference from Base Case, Same Scenario ($ Million)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Forecast Low	$ (808)	$ (868)	$ (817)	$ (835)	$ (668)	$ (818)	$ (804)	$ (732)
Forecast High	$ 827	$ 900	$ 819	$ 892	$ 678	$ 839	$ 825	$ 893
Reserve Ratio - 2%	$ (76)	$ (45)	$ (85)	$ (44)	$ (76)	$ (82)	$ (73)	$ (7)
Reserve Ratio - 1%	$ (76)	$ (3)	$ (85)	$ (44)	$ (76)	$ (16)	$ (73)	$ (3)
Reserve Ratio + 1%	$ 9	$ 23	$ 11	$ 5	$ 9	$ 11	$ 13	$ 80
Reserve Ratio + 2%	$ 24	$ 35	$ 15	$ 15	$ 24	$ 14	$ 28	$ 100
Wind Low Cap Cred (	$ 20	$ -	$ 11	$ 11	$ 20	$ 11	$ 25	$ 85
Wind High Cap Cred	$ (73)	$ -	$ (81)	$ (40)	$ (72)	$ (79)	$ (72)	$ (3)
CO2 @ 9	$ (936)	$ (1,159)	$ (937)	$ (1,045)	$ -	$ (945)	$ (934)	$ (928)
CO2 @ $34	$ 799	$ 1,024	$ 800	$ 926	$ -	$ 808	$ 797	$ 791
CO2 Reduction	$ 23	$ 364	$ 23	$ 10	$ 37	$ 22	$ 23	$ 23
Externalities Low	$ (83)	$ (83)	$ (83)	$ (94)	$ -	$ (83)	$ (83)	$ (83)
Wholesale Mkt Low (-	$ (286)	$ (295)	$ (286)	$ -	$ (209)	$ (287)	$ (286)	$ (285)
Wholesale Mkt High (	$ 195	$ 223	$ 195	$ -	$ 173	$ 196	$ 195	$ 194
Coal Low (-25%)	$ (415)	$ (463)	$ (415)	$ (451)	$ (501)	$ (417)	$ (414)	$ (413)
Coal High (+ 25%)	$ 340	$ 377	$ 340	$ 372	$ 485	$ 341	$ 339	$ 338
Natural Gas - $1.00	$ (272)	$ (392)	$ (273)	$ (376)	$ (193)	$ (277)	$ (271)	$ (268)
Natural Gas - $0.50	$ (114)	$ (173)	$ (114)	$ (171)	$ (92)	$ (116)	$ (113)	$ (112)
Natural Gas + $0.50	$ 95	$ 152	$ 96	$ 152	$ 89	$ 97	$ 95	$ 93
Natural Gas + $1.00	$ 190	$ 304	$ 190	$ 304	$ 177	$ 194	$ 189	$ 185
Natural Gas + $1.50	$ 280	$ 452	$ 281	$ 452	$ 266	$ 287	$ 279	$ 274
Natural Gas + $2.00	$ 372	$ 601	$ 374	$ 601	$ 354	$ 381	$ 370	$ 363
Solar @ $70	$ (3)	$ (3)	$ -	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)
Solar @ $85	$ (2)	$ (2)	$ -	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)
Solar @ $115	$ 2	$ 2	$ -	$ 2	$ 2	$ 2	$ 2	$ 2
Solar @ $130	$ 3	$ 3	$ -	$ 3	$ 3	$ 3	$ 3	$ 3
Solar @ $145	$ 5	$ 5	$ -	$ 5	$ 5	$ 5	$ 5	$ 5
Wind @ $30	$ (437)	$ -	$ (437)	$ (437)	$ (437)	$ (437)	$ (437)	$ (437)
Wind @ $35	$ (292)	$ -	$ (292)	$ (292)	$ (292)	$ (292)	$ (292)	$ (292)
Wind @ $40	$ (146)	$ -	$ (146)	$ (146)	$ (146)	$ (146)	$ (146)	$ (146)
Wind @ $50	$ 146	$ -	$ 146	$ 146	$ 146	$ 146	$ 146	$ 146
Wind @ $55	$ 292	$ -	$ 292	$ 292	$ 278	$ 292	$ 292	$ 292
Wind @ $60	$ 438	$ -	$ 438	$ 438	$ 371	$ 438	$ 438	$ 438
Capital Cost Low	$ (78)	$ (116)	$ (81)	$ (78)	$ (78)	$ (81)	$ (77)	$ (54)
Capital Cost High	$ 78	$ 116	$ 81	$ 78	$ 78	$ 81	$ 77	$ 54

	Wind Units Added, 2014-2029 (100 MW each)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	14	-	14	14	14	14	14	14
Forecast Low	14	-	14	14	14	14	14	14
Forecast High	14	-	14	14	14	14	14	14
Reserve Ratio - 2%	14	-	14	14	14	14	14	14
Reserve Ratio - 1%	14	-	14	14	14	14	14	14
Reserve Ratio + 1%	14	-	14	14	14	14	14	14
Reserve Ratio + 2%	14	-	14	14	14	14	14	14
Wind Low Cap Cred (- 25%)	14	-	14	14	14	14	14	14
Wind High Cap Cred (+ 25%)	14	-	14	14	14	14	14	14
CO2 @ 9	14	-	14	14	14	14	14	14
CO2 @ $34	14	-	14	14	14	14	14	14
CO2 Reduction	14	-	14	14	14	14	14	14
Externalities Low	14	-	14	14	14	14	14	14
Wholesale Mkt Low (- 25%)	14	-	14	14	14	14	14	14
Wholesale Mkt High (+ 25%)	14	-	14	14	14	14	14	14
Coal Low (-25%)	14	-	14	14	14	14	14	14
Coal High (+ 25%)	14	-	14	14	14	14	14	14
Natural Gas - $1.00	14	-	14	14	14	14	14	14
Natural Gas - $0.50	14	-	14	14	14	14	14	14
Natural Gas + $0.50	14	-	14	14	14	14	14	14
Natural Gas + $1.00	14	-	14	14	14	14	14	14
Natural Gas + $1.50	14	-	14	14	14	14	14	14
Natural Gas + $2.00	14	-	14	14	14	14	14	14
Solar @ $70	14	-	14	14	14	14	14	14
Solar @ $85	14	-	14	14	14	14	14	14
Solar @ $115	14	-	14	14	14	14	14	14
Solar @ $130	14	-	14	14	14	14	14	14
Solar @ $145	14	-	14	14	14	14	14	14
Wind @ $30	14	-	14	14	14	14	14	14
Wind @ $35	14	-	14	14	14	14	14	14
Wind @ $40	14	-	14	14	14	14	14	14
Wind @ $50	14	-	14	14	14	14	14	14
Wind @ $55	14	-	14	14	10	14	14	14
Wind @ $60	14	-	14	14	8	14	14	14
Capital Cost Low	14	-	14	14	14	14	14	14
Capital Cost High	14	-	14	14	14	14	14	14

	CT Units Added, 2014-2029 (192 MW each)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	3	-	3	3	3	3	3	2
Forecast Low	1	2	1	1	1	1	1	1
Forecast High	4	2	4	4	4	4	4	4
Reserve Ratio - 2%	2	3	2	2	2	2	2	2
Reserve Ratio - 1%	2	-	2	2	2	3	2	2
Reserve Ratio + 1%	3	4	3	3	3	3	3	3
Reserve Ratio + 2%	3	4	3	3	3	3	3	3
Wind Low Cap Cred (- 25%)	3	-	3	3	3	3	3	3
Wind High Cap Cred (+ 25%)	2	-	2	2	2	2	2	2
CO2 @ 9	3	-	3	3	3	3	3	2
CO2 @ $34	3	-	3	3	3	3	3	2
CO2 Reduction	3	-	3	3	3	3	3	2
Externalities Low	3	-	3	3	3	3	3	2
Wholesale Mkt Low (- 25%)	3	-	3	3	3	3	3	2
Wholesale Mkt High (+ 25%)	3	-	3	3	3	3	3	2
Coal Low (-25%)	3	-	3	3	3	3	3	2
Coal High (+ 25%)	3	-	3	3	3	3	3	2
Natural Gas - $1.00	3	-	3	3	3	3	3	2
Natural Gas - $0.50	3	-	3	3	3	3	3	2
Natural Gas + $0.50	3	-	3	3	3	3	3	2
Natural Gas + $1.00	3	-	3	3	3	3	3	2
Natural Gas + $1.50	3	-	3	3	3	3	3	2
Natural Gas + $2.00	3	-	3	3	3	3	3	2
Solar @ $70	3	-	3	3	3	3	3	2
Solar @ $85	3	-	3	3	3	3	3	2
Solar @ $115	3	-	3	3	3	3	3	2
Solar @ $130	3	-	3	3	3	3	3	2
Solar @ $145	3	-	3	3	3	3	3	2
Wind @ $30	3	-	3	3	3	3	3	2
Wind @ $35	3	-	3	3	3	3	3	2
Wind @ $40	3	-	3	3	3	3	3	2
Wind @ $50	3	-	3	3	3	3	3	2
Wind @ $55	3	-	3	3	3	3	3	2
Wind @ $60	3	-	3	3	3	3	3	2
Capital Cost Low	3	-	3	3	3	3	3	2
Capital Cost High	3	-	3	3	3	3	3	2

	CC Units Added, 2014-2029 (605 MW each)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	-	1	-	-	-	-	-	-
Forecast Low	-	-	-	-	-	-	-	-
Forecast High	-	1	-	-	-	-	-	-
Reserve Ratio - 2%	-	-	-	-	-	-	-	-
Reserve Ratio - 1%	-	1	-	-	-	-	-	-
Reserve Ratio + 1%	-	-	-	-	-	-	-	-
Reserve Ratio + 2%	-	-	-	-	-	-	-	-
Wind Low Cap Cred (- 25%)	-	1	-	-	-	-	-	-
Wind High Cap Cred (+ 25%)	-	1	-	-	-	-	-	-
CO2 @ 9	-	1	-	-	-	-	-	-
CO2 @ $34	-	1	-	-	-	-	-	-
CO2 Reduction	-	1	-	-	-	-	-	-
Externalities Low	-	1	-	-	-	-	-	-
Wholesale Mkt Low (- 25%)	-	1	-	-	-	-	-	-
Wholesale Mkt High (+ 25%)	-	1	-	-	-	-	-	-
Coal Low (-25%)	-	1	-	-	-	-	-	-
Coal High (+ 25%)	-	1	-	-	-	-	-	-
Natural Gas - $1.00	-	1	-	-	-	-	-	-
Natural Gas - $0.50	-	1	-	-	-	-	-	-
Natural Gas + $0.50	-	1	-	-	-	-	-	-
Natural Gas + $1.00	-	1	-	-	-	-	-	-
Natural Gas + $1.50	-	1	-	-	-	-	-	-
Natural Gas + $2.00	-	1	-	-	-	-	-	-
Solar @ $70	-	1	-	-	-	-	-	-
Solar @ $85	-	1	-	-	-	-	-	-
Solar @ $115	-	1	-	-	-	-	-	-
Solar @ $130	-	1	-	-	-	-	-	-
Solar @ $145	-	1	-	-	-	-	-	-
Wind @ $30	-	1	-	-	-	-	-	-
Wind @ $35	-	1	-	-	-	-	-	-
Wind @ $40	-	1	-	-	-	-	-	-
Wind @ $50	-	1	-	-	-	-	-	-
Wind @ $55	-	1	-	-	-	-	-	-
Wind @ $60	-	1	-	-	-	-	-	-
Capital Cost Low	-	1	-	-	-	-	-	-
Capital Cost High	-	1	-	-	-	-	-	-

	CO2 Emissions 2014-2029 (,000 Tons)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Forecast Low	125,688	147,216	125,798	144,773	136,978	126,543	125,430	124,827
Forecast High	138,649	157,584	138,748	156,993	148,323	139,458	138,400	137,850
Reserve Ratio - 2%	132,137	152,413	132,241	150,852	142,598	132,950	131,893	131,320
Reserve Ratio - 1%	132,137	152,310	132,241	150,852	142,598	132,962	131,893	131,320
Reserve Ratio + 1%	132,188	152,462	132,317	150,875	142,653	133,028	131,942	131,348
Reserve Ratio + 2%	132,212	152,498	132,317	150,878	142,677	133,028	131,966	131,391
Wind Low Cap Cred (- 25%)	132,212	152,310	132,317	150,878	142,677	133,028	131,966	131,368
Wind High Cap Cred (+ 25%)	132,137	152,310	132,241	150,852	142,598	132,950	131,893	131,320
CO2 @ 9	142,276	156,735	142,373	153,747	142,625	142,939	142,069	141,510
CO2 @ $34	101,162	120,086	101,294	122,690	142,625	102,072	100,885	100,259
CO2 Reduction	133,792	142,450	133,913	147,572	131,156	134,582	133,549	132,999
Externalities Low	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wholesale Mkt Low (- 25%)	130,067	151,346	130,179	150,864	138,080	130,949	129,803	129,185
Wholesale Mkt High (+ 25%)	146,148	162,131	146,359	150,864	148,998	146,932	145,886	145,362
Coal Low (-25%)	138,506	155,826	138,622	153,187	145,509	139,246	138,279	137,767
Coal High (+ 25%)	110,890	130,686	111,026	131,812	134,459	111,786	110,617	110,005
Natural Gas - $1.00	114,277	132,649	114,588	130,972	139,729	115,299	114,019	113,349
Natural Gas - $0.50	125,051	144,904	125,195	143,640	141,350	125,920	124,792	124,186
Natural Gas + $0.50	134,417	154,397	134,560	152,511	142,291	135,263	134,171	133,582
Natural Gas + $1.00	134,848	154,881	134,982	153,240	141,997	135,688	134,596	134,002
Natural Gas + $1.50	135,254	155,338	135,379	153,748	141,633	136,090	134,997	134,404
Natural Gas + $2.00	134,996	155,177	135,118	153,765	141,217	135,834	134,741	134,147
Solar @ $70	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Solar @ $85	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Solar @ $115	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Solar @ $130	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Solar @ $145	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wind @ $30	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wind @ $35	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wind @ $40	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wind @ $50	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Wind @ $55	132,148	152,310	132,292	150,864	148,560	133,002	131,904	131,320
Wind @ $60	132,148	152,310	132,292	150,864	152,774	133,002	131,904	131,320
Capital Cost Low	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320
Capital Cost High	132,148	152,310	132,292	150,864	142,625	133,002	131,904	131,320

	CO2 Difference From Base Case, Same Contingency (,000 Tons)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	-	20,162	144	18,716	10,477	854	(244)	(829)
Forecast Low	-	21,528	111	19,085	11,290	856	(258)	(861)
Forecast High	-	18,935	100	18,344	9,674	809	(248)	(799)
Reserve Ratio - 2%	-	20,276	104	18,715	10,461	813	(245)	(817)
Reserve Ratio - 1%	-	20,173	104	18,715	10,461	825	(245)	(817)
Reserve Ratio + 1%	-	20,274	129	18,688	10,465	840	(245)	(839)
Reserve Ratio + 2%	-	20,286	105	18,666	10,465	816	(246)	(821)
Wind Low Cap Cred (- 25%)	-	20,098	105	18,666	10,465	816	(246)	(844)
Wind High Cap Cred (+ 25%)	-	20,173	104	18,715	10,461	813	(245)	(817)
CO2 @ 9	-	14,459	97	11,471	350	663	(207)	(766)
CO2 @ $34	-	18,924	132	21,528	41,464	910	(276)	(902)
CO2 Reduction	-	8,658	121	13,780	(2,636)	790	(243)	(793)
Externalities Low	-	20,162	144	18,716	10,477	854	(244)	(829)
Wholesale Mkt Low (- 25%)	-	21,280	113	20,798	8,013	883	(264)	(882)
Wholesale Mkt High (+ 25%)	-	15,983	211	4,717	2,850	784	(262)	(785)
Coal Low (-25%)	-	17,320	115	14,680	7,002	739	(227)	(739)
Coal High (+ 25%)	-	19,796	136	20,922	23,570	896	(273)	(885)
Natural Gas - $1.00	-	18,372	311	16,696	25,453	1,022	(258)	(927)
Natural Gas - $0.50	-	19,854	145	18,590	16,299	870	(259)	(865)
Natural Gas + $0.50	-	19,981	144	18,094	7,875	846	(245)	(835)
Natural Gas + $1.00	-	20,032	133	18,392	7,148	840	(253)	(846)
Natural Gas + $1.50	-	20,084	125	18,494	6,378	835	(257)	(850)
Natural Gas + $2.00	-	20,181	122	18,768	6,220	837	(255)	(850)
Solar @ $70	-	20,162	144	18,716	10,477	854	(244)	(829)
Solar @ $85	-	20,162	144	18,716	10,477	854	(244)	(829)
Solar @ $115	-	20,162	144	18,716	10,477	854	(244)	(829)
Solar @ $130	-	20,162	144	18,716	10,477	854	(244)	(829)
Solar @ $145	-	20,162	144	18,716	10,477	854	(244)	(829)
Wind @ $30	-	20,162	144	18,716	10,477	854	(244)	(829)
Wind @ $35	-	20,162	144	18,716	10,477	854	(244)	(829)
Wind @ $40	-	20,162	144	18,716	10,477	854	(244)	(829)
Wind @ $50	-	20,162	144	18,716	10,477	854	(244)	(829)
Wind @ $55	-	20,162	144	18,716	16,412	854	(244)	(829)
Wind @ $60	-	20,162	144	18,716	20,625	854	(244)	(829)
Capital Cost Low	-	20,162	144	18,716	10,477	854	(244)	(829)
Capital Cost High	-	20,162	144	18,716	10,477	854	(244)	(829)

	CO2 Differnce From Base Case, Same Scenario (,000 Tons)							
	Base Case	No Wind	No Solar	No Market	No CO2 or External.	Low DSM	Medium DSM	High DSM
Base Case	-	-	-	-	-	-	-	-
Forecast Low	(6,461)	(5,094)	(6,494)	(6,091)	(5,648)	(6,459)	(6,474)	(6,493)
Forecast High	6,500	5,274	6,456	6,128	5,697	6,456	6,496	6,530
Reserve Ratio - 2%	(11)	103	(51)	(12)	(27)	(52)	(12)	-
Reserve Ratio - 1%	(11)	-	(51)	(12)	(27)	(40)	(12)	-
Reserve Ratio + 1%	39	152	25	11	27	25	38	28
Reserve Ratio + 2%	64	188	25	14	51	25	62	71
Wind Low Cap Cred (- 25%)	64	-	25	14	51	25	62	48
Wind High Cap Cred (+ 25%)	(11)	-	(51)	(12)	(27)	(52)	(12)	-
CO2 @ 9	10,127	4,425	10,081	2,883	-	9,937	10,165	10,191
CO2 @ $34	(30,987)	(32,224)	(30,998)	(28,175)	-	(30,930)	(31,019)	(31,061)
CO2 Reduction	1,644	(9,860)	1,621	(3,292)	(11,469)	1,580	1,645	1,679
Externalities Low	-	-	-	-	-	-	-	-
Wholesale Mkt Low (- 25%)	(2,082)	(964)	(2,113)	-	(4,546)	(2,053)	(2,101)	(2,135)
Wholesale Mkt High (+ 25%)	13,999	9,821	14,067	-	6,372	13,930	13,982	14,043
Coal Low (-25%)	6,358	3,516	6,330	2,322	2,883	6,244	6,375	6,447
Coal High (+ 25%)	(21,259)	(21,624)	(21,266)	(19,052)	(8,166)	(21,216)	(21,287)	(21,315)
Natural Gas - $1.00	(17,872)	(19,661)	(17,704)	(19,892)	(2,896)	(17,703)	(17,885)	(17,970)
Natural Gas - $0.50	(7,098)	(7,405)	(7,096)	(7,224)	(1,276)	(7,082)	(7,113)	(7,134)
Natural Gas + $0.50	2,268	2,087	2,269	1,646	(334)	2,261	2,267	2,262
Natural Gas + $1.00	2,700	2,571	2,690	2,376	(629)	2,686	2,692	2,683
Natural Gas + $1.50	3,106	3,029	3,087	2,884	(993)	3,087	3,093	3,085
Natural Gas + $2.00	2,848	2,868	2,826	2,900	(1,409)	2,831	2,837	2,827
Solar @ $70	-	-	-	-	-	-	-	-
Solar @ $85	-	-	-	-	-	-	-	-
Solar @ $115	-	-	-	-	-	-	-	-
Solar @ $130	-	-	-	-	-	-	-	-
Solar @ $145	-	-	-	-	-	-	-	-
Wind @ $30	-	-	-	-	-	-	-	-
Wind @ $35	-	-	-	-	-	-	-	-
Wind @ $40	-	-	-	-	-	-	-	-
Wind @ $50	-	-	-	-	-	-	-	-
Wind @ $55	-	-	-	-	5,935	-	-	-
Wind @ $60	-	-	-	-	10,148	-	-	-
Capital Cost Low	-	-	-	-	-	-	-	-
Capital Cost High	-	-	-	-	-	-	-	-

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Comments

Docket No. **E001/RP-14-77**

Dated this 31st day of July 2014

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Bobby	Adam	bobby.adam@conagrafoods.com	ConAgra	Suite 5022 11 ConAgra Drive Omaha, NE 68102	Electronic Service	No	OFF_SL_14-77_RP-14-77
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_14-77_RP-14-77
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_14-77_RP-14-77
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_14-77_RP-14-77
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_14-77_RP-14-77
City	Clerk	sschulte@ci.albertlea.mn.us	City of Albert Lea	221 E Clark St Albert Lea, MN 56007	Electronic Service	No	OFF_SL_14-77_RP-14-77
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_14-77_RP-14-77
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_14-77_RP-14-77
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_14-77_RP-14-77
David	Grover	dgrover@itctransco.com	ITC Midwest	901 Marquette Avenue Suite 1950 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_14-77_RP-14-77

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_14-77_RP-14-77
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_14-77_RP-14-77
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_14-77_RP-14-77
Paula	Johnson	paulajohnson@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_14-77_RP-14-77
Jim	Krueger	jkrueger@fmcs.coop	Freeborn-Mower Cooperative Services	Box 611 Albert Lea, MN 56007	Electronic Service	No	OFF_SL_14-77_RP-14-77
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_14-77_RP-14-77
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_14-77_RP-14-77
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_14-77_RP-14-77
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_14-77_RP-14-77
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_14-77_RP-14-77

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Steven	Nyhus	swnyhus@flaherty-hood.com	Flaherty & Hood PA	525 Park St Ste 470 Saint Paul, MN 55103	Electronic Service	No	OFF_SL_14-77_RP-14-77
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_14-77_RP-14-77
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	12 S 6th St Ste 1137 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_14-77_RP-14-77
Matthew J.	Schuerger P.E.	mjsreg@earthlink.net	Energy Systems Consulting Services, LLC	PO Box 16129 St. Paul, MN 55116	Electronic Service	No	OFF_SL_14-77_RP-14-77
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_14-77_RP-14-77
Marya	White	mwhite@misoenergy.org	MISO	1125 Energy Park Dr St. Paul, MN 55108	Electronic Service	No	OFF_SL_14-77_RP-14-77
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	Yes	OFF_SL_14-77_RP-14-77