STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. a Division of MDU Resources Group, Inc.
Advance Determination of Prudence- 88 MW Turbine Application — **Case No. PU-11-395**

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
88 MW Combustion Turbine
Public Convenience & Necessity — **Case No. PU-11-396**

AFFIDAVIT OF SERVICE BY CERTIFIED & ELECTRONIC MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Cara DeSaye deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **12th** day of **December, 2011,** she deposited in the United States Mail, at Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and containing a photocopy of:

Advocacy Staff Direct Testimony Richard Hahn- Redacted

Other Exhibits

The envelope was addressed as follows:

Daniel Kuntz
MDU Resources Group, Inc.
PO Box 5650
Bismarck ND 58506-5650

Cert No. 7009 2820 0002 9238 0767

Cara DeSaye further deposes and says that on the **12th** day of **December, 2011,** she electronically mailed **one** photocopy of the same.

The electronic mail was addressed as follows:

Tamie Aberle
Montana-Dakota Utilities Co.
tamie.aberle@mdu.com

29 PU-11-396 Filed 12/12/2011 Pages: 55
Affidavit of Service cert. and email - Advocacy Staff direct testimony of Richard Hahn - redacted and other exhibits
Public Service Commission

42 PU-11-395 Filed 12/12/2011 Pages: 55
Affidavit of Service cert. and email - Advocacy Staff direct testimony of Richard Hahn - redacted and other exhibits
Public Service Commission

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Cara DeSaye

Subscribed and sworn to before me this **12th** day of **December, 2011.**

Geralyn R Schmaltz
Notary Public

SEAL

GERALYN R. SCHMALTZ
Notary Public
State of North Dakota
My Commission Expires Oct. 5, 2016

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

APPLICATION OF MONTANA-DAKOTA UTILITY FOR AN ADVANCE DETERMINATION OF PRUDENCE AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ITS PROPOSED 88 MW GAS-FIRED COMBUSTION TURBINE PROJECT	)))))	DOCKET NO. PU-11-395 DOCKET NO. PU-11-396

PUBLIC REDACTED VERSION

INITIAL TESTIMONY

OF

RICHARD S. HAHN

ON BEHALF OF

THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

DECEMBER 12, 2011

DOCKET NO. PU-11-395 AND PU-11-396

INITIAL TESTIMONY OF RICHARD S. HAHN

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DOCKET NO. PU-11-163 AND PU-11-165

INITIAL TESTIMONY

OF

RICHARD S. HAHN

I. QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Richard S. Hahn. I am employed by La Capra Associates, Inc. ("La Capra") as a Principal Consultant. My business address is One Washington Mall, 9^{th} Floor, Boston, Massachusetts 02108.

Q. Please summarize your professional experience and qualifications.

A. I received my Bachelor's in Science, Electrical Engineering, in 1973, and my Masters in Science, Electrical Engineering, in 1974, both from Northeastern University. I received my Masters in Business Administration from Boston College in 1982. Since joining La Capra, I have worked on many projects related to energy markets, forecasts of wholesale market prices, utility resource planning projects, and asset valuations. Prior to joining La Capra, I worked at NSTAR Electric & Gas (formerly Boston Edison Company) from 1973 to 2003. Throughout my career, I have gained and demonstrated considerable experience and expertise in utility planning activities. I am a registered professional electrical engineer in the Commonwealth of Massachusetts. My resume is provided in Exhibit RSH-1.

Q. Please summarize La Capra Associates and its business.

A. La Capra Associates provides consulting services in energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. We serve a national and international clientele from our offices in Boston, Massachusetts, Portland, Maine, and Williston, Vermont providing consulting services to a broad range of organizations involved with energy markets, including renewable energy producers, private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the North Dakota Public Service Commission Advocacy Staff ("Advocacy Staff").

Q. Please describe the purpose of your testimony.

A. La Capra has been retained by the Advocacy Staff to assist in reviewing the application of the Montana-Dakota Utility ("MDU" or "The Company") for an Advance Determination of Prudence ("ADP") and a Certificate of Public

Convenience and Necessity ("CPCN") related to its proposed construction of an 88 MW gas-fired combustion turbine in Mandan, North Dakota ("the Application"). Specifically, we were asked to provide a detailed analysis and conclusion related to the necessity and economic prudence for MDU to construct, own and operate an 88 MW simple cycle combustion turbine. Our assessment methodology was to utilize the discovery process to obtain a detailed understanding of MDU's filing and the underlying assumptions, inputs and analyses.

III. SUMMARY AND CONCLUSIONS

Q. Please summarize your conclusions and recommendations.

A. Based upon my review of MDU's Application, I reach the following conclusions.

- I find that the Company's load forecast methodology and results are generally reasonable, and combined with the expiration of certain power purchases, demonstrate a need for new capacity.
- The Company's analysis ignores certain resources identified in the 2010 RFP that are feasible and when analyzed result in considerable savings relative to the proposed CT unit.
- There are other feasible, more economic alternatives to the proposed project; the Company has not demonstrated that its proposal is the least-cost option for North Dakota ratepayers.
- Because the Company has not selected the least-cost alternative, its request for an ADP and a CPCN should not be granted.

IV. OVERVIEW OF THE APPLICATION

Q. Please summarize MDU's Application.

A. MDU has filed an application for an Advance Determination of Prudence and a Certificate of Public Convenience and Necessity to construct, own and operate an 88 MW SCCT, as well as necessary transmission interconnection and natural gas pipeline facilities (collectively, "the Project"). The Project will be located adjacent to MDU's existing coal-fired Heskett Generating Station near Mandan, North Dakota. The site selection, need and justification for the project are based on MDU's 2011 Integrated Resource Plan ("2011 IRP")[1]. The total cost of the project, including Allowance for Funds used in Construction ("AFUDC"), is estimated to be $85.6 million, of which $58.2 million would be allocated to North Dakota customers.

Q. Please summarize the 2011 IRP analysis of need and justification for the project.

A. According to its 2011 IRP, MDU expects to be facing a capacity deficit of about 150 planning resource credits ("PRC") by the summer of 2015 with the expiration of a capacity purchase agreement. The Company used the Electric Generation Expansion Analysis ("EGEAS") computer model to develop a least-cost integrated resource expansion plan based on a set of supply alternatives assumed to be available. At least one 88 MW SCCT was chosen in 2015 in each scenario modeled by MDU, with the exception of the low growth sensitivity scenario.[2]

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1 Filed with the Commission on May 12, 2011 (Case No. PU-11-158).
2 2011 IRP, Attachment C, page 18, Table 3-1.

The Application cites this analysis to demonstrate the need and justification for the Project.

Q. Please explain how the Mandan site was selected for the 88 MW SCCT.

A. The 2011 IRP documents a combustion turbine site study process[3] that evaluated three candidate sites in North Dakota chosen for their availability of water, electric transmission, and natural gas supply. The Mandan site was chosen because it had the lowest estimated capital cost, the highest projected capacity, and the lowest potential operational cost due to synergies with the existing Heskett Station. The study also chose a GE 7EA Frame unit over a comparable aero-derivative type turbine design. The Mandan cost estimates developed as part of the combustion turbine site study were used to model the 88 MW SCCT resource alternative made available to the resource expansion analysis described above.

V. STANDARD OF REVIEW

Q. What approvals is the Company seeking in this application?

A. MDU is seeking an Advance Determination of Prudence and a Certificate of Public Convenience and Necessity for its proposed construction of an 88 MW SCCT and associated interconnection and natural gas pipeline facilities.

Q. What is the basis for the Company's request for an ADP?

A. Provisions for an advance determination of prudence are set forth in North Dakota law.[4] That provision was amended in 2011 and became law on August 1 of this

[3] 2011 IRP, Attachment F.
[4] N.D. Century Code § 49-05-16.

year. I have conducted my review of this application under the provision of the now-current advance determination of prudence law.

Q. What are the key provisions of the ADP law as it pertains to the Company's application?

A. The statute allows a utility to apply for an ADP for modification of an energy conversion facility, among other resource additions. It is my understanding that the Project qualifies for consideration.

For qualifying resource additions, the Commission may issue an order approving the request for an ADP if the Commission finds the project to be prudent. There are added considerations for resource additions that are in-state such as the project in question. I have conducted my review using the provisions that apply to in-state resources. Specifically, the rebuttable presumption of prudence afforded in-state resource additions[5] and the requirement to consider the benefits of having the resource located in-state[6] would apply to this Application. If the Commission grants a determination of prudence, the project would be subject to specific reporting requirements until its date of commercial operation[7].

Q. What is the basis for the Company's request for a CPCN?

A. Provisions for a certificate of public convenience and necessity are set forth in North Dakota law.[8] Specifically, § 49-03.1-04 states that five factors are to be taken into consideration before granting a CPCN:

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[5] N.D. Century Code § 49-05-16(7).

[6] N.D. Century Code § 49-05-16(1)(d).

[7] N.D. Century Code § 49-05-16(3).

[8] N.D. Century Code § 49-03.

1. Need for the service.
2. Fitness and ability of applicant to provide the service.
3. Effect on other public utilities providing similar service.
4. Adequacy of proposed service.
5. The technical, financial, and managerial ability of the applicant to provide service.

Q. How have you conducted your review in light of this understanding?

A. I have investigated MDU's Application to determine if the five point requirements of § 49-03.1-04 had been met. In particular, I focused on the stated need for the project, the alternatives considered, and the adequacy of the proposed project to meet that need.

VI. STATUS OF MISO CAPACITY MARKETS

Q. What is your understanding of the current status of capacity markets and other mechanisms in MISO related to resource adequacy?

A. My understanding is that resource adequacy in MISO is covered under Module E of the MISO tariff. Module E states that the transmission provider will establish planning reserve margins ("PRM") for each load serving entity ("LSE") and that the final PRM for a given LSE will be either the MISO-established PRM or a state-established PRM.[9] The LSE is then responsible for providing MISO with its annual load forecast and for procuring capacity in the form of planning reserve credits ("PRC"). A PRC represents a MW-Month of unforced capacity. In

9 MISO Tariff, Module E, page 1; MISO Business Practices Manual: Resource Adequacy, June 13, 2011, page 3-7.

general, all resources are eligible to be capacity resources so long as they are network resources and not specifically assigned to serve other load, unless MISO determines that the capacity is undeliverable. A purchased power agreement ("PPA") can likewise be considered a capacity resource as long as it is backed by a resource that is not committed elsewhere. In addition to owned units and bilateral PPAs, there is also a voluntary capacity auction ("VCA") where LSEs can procure additional PRCs for the upcoming month. Finally, if an LSE is unable to procure sufficient PRCs for a given month there is a financial settlement for the amount of PRCs that an LSE is short. This charge is based on a cost of new entry ("CONE") value set by MISO.[10]

Q. What is your understanding of proposed changes to MISO's resource adequacy construct?

A. On July 20, 2011 MISO filed proposed modifications to its Module E[11] before the Federal Energy Regulatory Commission ("FERC"). This filing was in response to several FERC orders from 2010 directing MISO to address certain aspects of its resource adequacy requirements ("RAR"). The issues surrounding this docket are varied and complex and beyond the scope of this testimony, but I will attempt to summarize a few of the key items. According to the MISO filing, some of the key elements of the proposed new resource adequacy construct include:

1. The proposed new resource adequacy construct would be locational, incorporating local resource zones with individual local resource zone

[10] This explanation greatly simplifies the actual process for testimony purposes.

[11] Technically, due to the extensive nature of the changes MISO has proposed to issue a Module E-1 to incorporate the existing Module E plus all changes and plans to file to retire the existing Module E once all obligations under it are complete. Effectively, the result of this in the long term will be a new modified Resource Adequacy Module.

transfer limits and capacity requirements;

2. The proposed new resource adequacy construct would be conducted for a single planning year at a time;
3. The creation of a new annual Planning Resource Auction to replace the current monthly voluntary capacity auction;
4. Self-scheduling and "opt out" options;
5. Hedging mechanisms for LSEs who own Planning Resources located in Local Resource Zones with lower clearing prices than the Local Resource Zone where their load is located[12]
6. Establishing energy efficiency resources as a new type of resource for participation in the proposed new capacity market;
7. Modifications to enable Load Modifying Resources ("LMR") "to participate in auctions in a matter that is comparable to other Planning Resources."[13]

MISO requested an effective date of October 1, 2012 which would make the first planning year under the new construct June 2013 – May 2014.

In the five months that have passed since MISO's original filing there have been numerous motions to intervene and many protests against various aspects of MISO's proposed changes. Many intervenors take exception to MISO's proposed

12 AFFIDAVIT OF KEVIN LARSON ON BEHALF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. (TAB E of the MISO filing dated 7/20/2011), pages 15-16. According to the testimony of Todd P Hillman of MISO, this hedge would be available for LSEs who invest "in new or upgraded Transmission System facilities between their Planning Resource and the LSE's Load (which is located in a different Local Resource Zone than the LSE's Planning Resource), as described in proposed Tariff Section 69A.9(g)."

13 AFFIDAVIT OF TODD P. HILLMAN ON BEHALF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. (TAB F of the MISO filing dated 7/20/2011), page 29.

new resource adequacy construct and are looking for substantial changes. In addition, the various parties are not in complete agreement as to what those changes should be. At this point in time, the final resolution of these issues is unclear.

Q. What is your understanding regarding the current state of available capacity in MISO?

A. My understanding is that currently MISO has excess capacity and that under most scenarios MISO projects continued excess capacity for some years; possibly as far out as 2020. The 2010 Long Term Resource Assessment stated "The projected Midwest ISO reserve margin ranges from 25.4% in 2010 to 16.1% in 2019. This margin never drops below the Midwest ISO system Planning Reserve Margin of 15.4% established for the 2010-2011 planning year."

VII. NEEDS ASSESSMENT

Q. What analysis did MDU perform to determine the need for this project?

A. As discussed on page 8 of the Application, "The need for the 88 MW SCCT has been determined and documented through the 2011 IRP process."

Q. What is the nature of need that the IRP identified?

A. As MDU illustrates in a figure entitled "Planning Resource Credit and Planning Reserve Margin Requirement Base Forecast" on page 8 of the Application, beginning in year 2015 the Company does not have sufficient PRCs to cover its obligation (planning reserve margin requirement, or "PRMR"). According to MDU the base case need is 149.5 PRCs in 2015.

Q. What is PRMR?

A. The PRMR is the long-term planning requirement for resource adequacy.[14] While the actual calculation of PRMR is fairly complex, it can be thought of as the load plus reserve margin for a given zone or LSE. This is the target level of capacity that MDU must procure to meet its capacity obligation.

Q. How did MDU calculate its PRMR?

A. In general terms, MDU calculated its summer peak forecast before DSM, subtracted forecasted DSM contribution to peak, added in losses and applied the MISO PRM.

Q. Is this an appropriate manner for calculating MDU's obligation?

A. Yes, this forecast approximately models the process that will occur each year when MISO calculates MDU's actual obligation. Therefore, the methodology used by MDU is appropriate, and the only question is whether the assumptions used were reasonable.

Q. Did you review the underlying assumptions that went into the calculation of annual PRMR?

A. I did. I reviewed MDU's peak demand forecast, which came from the report "Historical and Forecasted Energy and Demand".[15] I also reviewed the discussions regarding peak demand forecasting and peak demand reduction forecasting in the Company's 2011 IRP. Finally, I reviewed the responses to various discovery questions intended to further explain the forecast of demand. Throughout this review I focused primarily on the identified need in 2015, but

14 MISO Business Practices Manual: Resource Adequacy (Manual No. 11), page 3-18.
15 2011 IRP, Attachment A, page 23.

also reviewed the forecast over the full study period, as trends in both energy and peak demand needs can alter the advisability of various capacity options.

Q. How did MDU calculate its forecast of peak demand?

A. MDU used an econometric model to forecast future peak demand before DSM that was based off of the historical summer peaks adjusted to add back interruptible load events. This model was chosen in part to reflect that "air conditioning is becoming more prevalent over time and air conditioning load is driving much of the increase in summer peak demand."[16] This method produced an interim forecast with a growth rate that was consistent with 2000–2010 historical data. Two new sources of peak demand were added to this forecast: "TransCanada" and "Other New LC&I". These two sources combined add 28 MW of new peak by 2015, which would be a roughly 5% increase in peak demand. The majority of this is from TransCanada. Figure 1 below summarizes this information.

Figure 1

Average Annual Growth Rate	Summer Pk as originally forecasted	Summer Peak w/ new load	Peak Demand After all DSM (Consvtn, DR & Int)	Without TransCanada
2000 - 2010			1.52%	
2011 - 2030	1.56%	1.79%	1.81%	1.64%
2011 - 2015	1.66%	3.00%	2.96%	1.98%
2015 - 2030	1.53%	1.46%	1.50%	1.55%

[16] MDU 2011 IRP, Attachment A, page 16.

Q. Did you review the company's assumptions regarding peak reductions due to DSM programs?

A. I reviewed the calculations shown in Table 2-1 in Volume I of the 2011 IRP. Additionally, I reviewed the discussion of DSM reductions to peak demand in Attachments A and B to the 2011 IRP. Finally, I reviewed the responses to discovery questions as they pertained to forecasted DSM.

Q. Please describe the reduction in peak demand due to DSM assumed in the Company's 2011 IRP analysis.

A. MDU plans to implement demand response programs that will reduce integrated system demand by 48 MW, or 8.3%, by 2015. An additional 1.5 MW reduction is expected due to energy efficiency programs.[17] Some of these reductions were already planned for in the 2009 IRP and are therefore already included in the current load forecast. An additional 25 MW were modeled as a resource available to EGEAS. Finally, 8.7 MW of incremental DSM was added in 2014 and beyond to model the total 49.5 MW DSM program assumed in the IRP.[18]

Q. Did you review any other aspects of MDU's load forecasting?

A. Yes, in addition to peak demand and reduction forecasts I also reviewed MDU's energy forecast as displayed in the report "Historical and Forecasted Annual Sales by Sector".

Q. If the energy forecast is not part of the forecasted need, why did you perform this review?

17 2011 IRP, Attachment B, page 3.
18 2011 IRP, Main Report, page 3.

A. Although forecasted energy is not part of the calculation of need discussed above, it is an important part of determining the least-cost solution for serving that need. In general, capacity need without a corresponding energy need would lead towards a peak reducing asset (DR or combustion turbine) while a need for both energy and capacity would suggest that other solutions such as combined cycles, or combination solutions would be more appropriate.

Q. How did MDU forecast annual energy?

A. MDU separated its energy forecasting into five categories: Residential ("Res"), Small Commercial and Industrial ("SC&I"), Large Commercial and Industrial ("LC&I"), Street Lighting and Miscellaneous. There was little to no growth in the last two categories, so the forecast essentially amounts to predicting the growth of the Res, SC&I and LC&I classes. MDU forecasted a small amount of Res growth and a moderate amount of SC&I growth. In both cases the growth was fairly steady over the study years, and in both cases it was significantly below the historical 2000–2010 period. Finally, the LC&I growth rate spiked from 2011–2015 at roughly 3 times the 2000–2010 historical average growth rate and then declined to slightly below the historical rates for the rest of the study period. Figure 2 below summarizes this information.

Figure 2

Average Annual Growth Rate	Residential	Small C&I	Large C&I	Street Lighting	Miscellaneous
2000 - 2010	2.50%	4.31%	2.06%	-0.16%	0.66%
2011 - 2030	1.33%	2.49%	2.51%	0.01%	0.22%
2011 - 2015	1.42%	2.49%	6.07%	0.01%	0.23%
2015 - 2030	1.30%	2.49%	1.59%	0.01%	0.22%

Q. What were the results of this forecasting effort?

A. Average energy growth from 2011–2030 was 2.1% in the base case. This is considerably below the average growth rate from 2000–2010 of 2.72%. As an example, an annual growth rate of 2.72% over the 2011–2030 timeframe would lead to over 500,000 more MWH of energy in 2030. Despite the load forecast having an average annual growth rate below the previous ten-year historical average, the load forecast does project a higher than historical average growth rate for the next 5 years followed by a below average growth rate for the next 15 years. Figure 3 below summarizes this information:

Figure 3

Average Annual Growth Rate	Total Sales
2000 - 2010	2.59%
2011 - 2030	2.05%
2011 - 2015	3.58%
2015 - 2030	1.65%

Q. Please describe the reduction in load projected due to energy efficiency ("EE") programs.

A. MDU has set a goal of annual reductions of 0.25% of annual energy sales by 2015 through EE, for a total of 0.23% savings by 2030. The Company acknowledges that this target is below the national average, and plans an EE potential study for Montana customers in mid-2012.[19] This is an extraordinarily low goal for EE. Numerous studies point to much higher potential, even when accounting for rural areas. For example, a 2009 study by the Electric Power Research Institute concluded that the Midwest region has a realistic achievable potential (accounting for technical limits, economics, political and customer participation barriers) of 7.5% reductions through EE by 2030.[20]

Q. What are your conclusions regarding the need for the proposed project?

A. Exhibit RSH-2 provides a summary of the MDU load forecast for demand and annual energy from 2011 to 2030. Also shown for comparison purposes is

19 2011 IRP, Attachment B, pages 2-3.

20 Report available at http://my.epri.com/portal/server.pt?Abstract_id=000000000001016987.

historical data from 2000 through 2010. Note that this forecast calls for annual energy requirements to grow considerably faster than peak load, resulting in an annual load factor of 65% in 2030 compared to 55% in 2000. Some of this may be due to the significant demand response programs expected without corresponding progress on EE. It is unusual to identify a summer-peaking utility with an increasing load factor. However, the Company's forecasting methodology is reasonable. The resulting forecasted loads are consistent with recent historical trends and are reasonable over the long-term. The load forecast combined with the expiration of existing contracts in the 2011 to 2015 time period demonstrate a need for some new capacity.

Q. What is a PRC?

A. A PRC represents 1 MW of qualified unforced capacity from a Planning Resource for a particular month. The PRC of a given unit is the capacity of that unit reduced by the expectation of outage. This concept of capacity, most often referred to as unforced capacity ("UCAP") rewards units that are more reliable by giving them more PRC value than less reliable alternatives.

Q. Did you review the underlying assumptions that went into the calculation of annual PRC?

A. Yes, I did.

Q. How did MDU calculate annual PRC values?

A. For MDU's owned thermal units the Company began with MISO Generator Verification Test Capability ("GVTC") values. MDU then applied the appropriate XEFORd[21] percentage against the GVTC capacity. The result was PRC values per unit. Electric load carrying capacity ("ELCC") was used for wind resources. The contracted capacity value was used for purchases.

Q. What are your conclusions related to MDU's calculation of annual PRC?

A. MDU's calculation of the capacity credit to be received by its existing portfolio of owned and purchased assets appears to be reasonable.

VIII. ADEQUACY OF THE PROPOSED PROJECT

Q. Please describe your understanding of how the 88 MW SCCT supply option was developed for consideration in the EGEAS resource expansion modeling.

A. MDU first conducted a Combustion Turbine Site Study to choose the turbine type and site for a reference SCCT.[22] The revised capital and fixed O&M costs for the Mandan site developed in the Site Study were then used to update the input assumptions for a reference 88 MW SCCT in the supply options available to the EGEAS resource expansion model.[23]

Q. Have any significant assumptions changed since the Site Study was completed?

A. After completing the Site Study, MDU decided to change from an 8-inch natural gas pipeline to a 10-inch pipeline to accommodate possible future incremental natural gas needs at the site.[24] As a result, the cost of the 24-mile natural gas pipeline and tap increased from $15 million assumed in the Site Study to $18.4

[21] XEFORd refers to the equivalent forced outage rate during demand for need, excluding non-generation related outages (e.g. transmission outages).

[22] 2011 IRP, Attachment F.

[23] See Response to LCA Data Requests 2-3(a) and 1-25.

[24] Application, page 7.

million estimated in the Application. The other two sites, which only require one-mile pipelines, would only have increased pipeline costs about $250,000 by the same change in specifications.[25] A comparison of the original self-build capital cost estimate and a revised estimate with the cost of a 10-inch natural gas pipeline is shown in Figure 4 below.

Figure 4

Baseload PS&I Self-Build Capital Cost Estimates in Site Study and Revised for 10-inch NG Pipeline

(2010$/baseload kW)

	Richardton	Linton	Mandan (Normal)	Mandan (Conservative)
Site Study Estimate (assumes 8-inch pipeline)[26]	$851	$854	$813	$857
Revised estimate with 10-inch pipeline costs[27]	$854	$857	$852	$895

Q. Please describe the "conservative" case for the Mandan site.

A. The Site Study included a conservative case for the Mandan location that assumed about $3.8 million in additional capital cost for the installation of selective catalytic reduction ("SCR") for NOx control and catalytic oxidation for CO control.[28] However, a June 2011 environmental screening analysis performed on behalf of MDU has indicated that **[TRADE SECRET DATA BEGINS** __________ **TRADE SECRET DATA ENDS]**[29] Based on this analysis, the Company has argued that the conservative assumptions for the Mandan site are no

[25] See Response to LCA Data Request 1-8.
[26] 2011 IRP, Attachment F, page 12, Table 7.
[27] Revised estimates developed using spreadsheet "CONFIDENTIAL SCCT.CapEx.IRP.xlsx" provided in response to LCA Data Request 1-23.
[28] See 2011 IRP, Attachment F, page 11, Footnote 5. See also Response to LCA Data Request 1-10.
[29] See Response to LCA Data Request 1-9, Attachment A, page 8.

longer necessary. However, the decision on which technologies will be required has not yet been made.

Q. Does the selection of the Mandan site appear reasonable to you?

A. Based on the information contained in the Site Study, it does appear that the selection of the Mandan site over the Linton and Richardton sites was reasonable, provided the additional environmental permitting complexities assumed in the conservative case can be dismissed. Based on the June 2011 environmental screening analysis and the EPA's National Combustion Turbine Spreadsheet,[30] it appears unlikely that New Source Review permitting will require an SCR or catalytic oxidation as assumed in the conservative case. Even with the updated pipeline costs, the Mandan site in the normal case has similar capital costs to the other two sites. With capital costs similar across the candidate sites, the expected system reliability benefits in the Mandan area,[31] and reduced operating costs due to the proximity to an existing resource provide a reasonable basis to choose the Mandan site.

Q. Does the modeling of an SCCT unit in EGEAS seem reasonable?

A. It appears that the input assumptions for the 88 MW SCCT in the resource expansion modeling were reasonable. The Company has argued that its capital cost assumptions are conservative (high) because they are taken from the conservative environmental permitting case. As shown in Figure 4, the $857 per kW baseload cost assumed for the EGEAS modeling is close to the cost for the Mandan site in the normal case when revised natural gas pipeline costs are

30 http://www.epa.gov/region4/air/permits/.
31 See Response to LCA Data Request 1-6.

considered. Therefore, I would consider the costs modeled to be a "base case" estimate and not a "conservative" cost estimate as characterized in the Application. A conservative cost estimate would be $895/kW. I would also note that the EGEAS analysis was apparently run without including AFUDC. For this and every new-built resource option, excluding AFUDC will result in an underestimation of the capital costs incurred. The Application requests allowance of $10.6 million for AFUDC, or 12% of the total proposed investment.

IX. OTHER SUPPLY OPTIONS AND ASSUMPTIONS

Q. In addition to the 88 MW SCCT, what other resource alternatives did the Company model in EGEAS?

A. The Company modeled several resource alternatives that could compete to meet its 2015 resource needs:[32]

- 43 MW Aero-derivative CT
- 140 MW CCCT
- New Coal (blocks of 30 MW)
- Self-Built Wind (blocks of 30 MW)
- Purchased Wind (blocks of 25 MW)[33]
- Demand Response Program (blocks of 12.5 MW based on an accepted bid to the 2010 RFP)
- Big Stone AQCS project (105.9 MW)

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[32] 2011 IRP, Attachment C, page 15, Table 2-7.

[33] Energy Only based on Acciona Proposal from the 2010 RFP; see response to data request LCA 2-12c.

- 155 MW of New Purchased Capacity in a 5-yr Contract or 10 year Contract[34]
- 345 MW of New Purchased Capacity in a 20-yr Contract[35]

Q. What issues have you identified regarding the Company's modeling of these resources?

A. I have found issues with the Company's modeling of the 43 MW Aero-derivative CT, self-built and purchased wind, new CCCTs, and new purchased capacity.

Q. Please describe the issues with respect to the 43 MW Aero-derivative CTs.

A. The 43 MW SCCT planning alternative's equivalent forced outage rate ("EFOR") in EGEAS is 22.31% compared to 6.45% for the 88 MW SCCT. Because MISO uses unforced capacity to set PRCs for resource adequacy, the higher EFOR for the 43 MW SCCT causes it to receive only 33.4 PRCs for 43 MW of rated capacity. When asked to justify this assumption in discovery, the Company provided a table of forced outage rate assumptions used by MISO for setting PRC values for new resources without 12 months of NERC Generating Availability Data System ("GADS") data.[36] My understanding is that the rate is so high for small SCCTs for two reasons: a) EFORs look high for peaking units because one outage can create a high EFOR for units that run infrequently; and b) MISO bases its assumptions on historical data, which represents a broad range of units. Although this assumption is appropriate for calculating PRCs for the first year, I do not believe it is representative of actual turbine operation for new aero-derivative units. Therefore, the EFOR should have been a much lower number

34 Based on Calpine Proposal from 2010 RFP; see response to LCA Data Request 2-12.
35 Also based on Calpine Proposal from 2010 RFP; see response to LCA Data Request 2-12.
36 LCA Data Request 3-1.

for the 43 MW SCCT planning alternative in EGEAS. The PRCs for this planning alternative should have reflected the need to use a 22.31% EFOR, but only for the first year. EGEAS allows users to set a trajectory on reserve capacity, which should have allowed the Company to increase the PRCs for this alternative for the remaining study period.

Q. Please describe the issues with respect to wind resources.

A. First, the Company explicitly states that the purchased wind resource alternative considered in the model is energy-only, i.e. that it carries no PRC benefits.[37] **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]**[38] **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** without any corresponding reserve capacity benefit.[39] This erroneously inflates the cost of purchased wind energy and makes EGEAS less likely to select this resource. To correct this problem, the Company should have removed the fixed O&M charge or as an alternative, included the appropriate PRCs and modeled purchased wind energy and capacity together as one resource.

Second, self-built wind was modeled with an installation cost of $2,400/kW. According to my best available sources, this is too high. An installation cost of $1,750/kW is likely more appropriate and would also make EGEAS more likely to select wind resources.

Q. Please describe the issues with respect to new CCCTs.

37 2011 IRP, Attachment C, page 15, Table 2-7.

38 CONFIDENTIAL Response to LCA Data Request 1-32.

39 Response to LCA Data Request 1-22 and 2011 IRP, Attachment C, Table 2-7.

A. The CCCT capital cost is listed as $1,150/kW in Table 2-7 of the 2011 IRP but as $750/kW in EGEAS.[40] When asked to reconcile the discrepancy, the Company claimed that $750/kW is the incremental cost above an 88 MW CT and that EGEAS would only select a CCCT resource by upgrading an 88 MW CT.[41] As is shown in the figure below, summing the capital costs of the 88 MW CT and incremental CCCT still results in an overall capital cost that is higher than $1,150/kW. The result is actually closer to $1,300/kW. The Company has confirmed that this was an error, and that the CCCT resource should have been modeled with a $611/kW incremental capital cost.[42]

Figure 5

Calculation of total CCCT capital cost based on the cost of an 88 MW CT and the assumed CCCT incremental cost.

kW		$/kW		Total Cost
88,000	*	$ 857	=	$ 75,416,000
140,000	*	$ 750	=	$ 105,000,000
				$ 180,416,000

Total Cost		Total kW		Total Avg $/kW
$ 180,416,000	/	140,000	=	$ 1,289

40 Response to LCA Data Request 1-22
41 Response to LCA Data Request 2-3b
42 Response to LCA Data Request 4-2.

Modeling the CCCT solely as an incremental resource could also add bias to the model toward adding an 88 MW CT, since EGEAS may wish to select it only as a bridge to a CCCT.

Q. Please describe the issues with respect to new purchased capacity resource modeling.

A. The new capacity resources were based on the Calpine proposals from the 2010 RFP results.[43] The specific proposals were provided and summarized in a confidential PowerPoint presentation.[44] **[TRADE SECRET DATA BEGINS __________ TRADE SECRET DATA ENDS]** However, the five-year and ten-year contracts use an energy price of $107.41/MWh, which seems high. In response to a discovery request, the Company provided a spreadsheet showing how the proposal terms were translated into an overall energy charge.[45] A key factor contributing to the high energy charge is that the unit was assumed to run for four hours at 50% capacity for each start. This spreads the $8,400 start charge over 310 MWh, resulting in a rate of $27.10/MWh. The Calpine proposal **[TRADE SECRET DATA BEGINS __________ TRADE SECRET DATA ENDS]** which is far more reasonable. Had the Company used a more appropriate energy charge for this planning alternative, it would have made EGEAS more likely to select this purchased capacity as a resource.

Q. Were there other supply options inappropriately excluded in the MDU analysis?

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43 Response to LCA Data Request 2-11.

44 CONFIDENTIAL Response to LCA Data Request 1-32.

45 Response to LCA Data Request 4-3, "Response 4-3 Calpine.xlsx".

A. Yes. The **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** ("ND wind project") and the **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** ("IL CT") PPA were initially selected in the 2010 RFP analysis but later rejected.

Q. Please describe the ND wind project.

A. The ND wind project is a proposed 150 MW wind farm **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** North Dakota. Energy from this wind farm was offered in response to the 2010 RFP **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]**[46]

Q. Why did the Company not include this resource in its IRP modeling analysis?

A. Although the resource was initially selected as a least-cost resource by EGEAS when examining the 2010 RFP bids,[47] the Company later removed the project from consideration due to concerns over transmission interconnection costs. **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]**[48] **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]**[49]

Q. Do you agree the project should have been removed from consideration?

A. No. The final MISO SIS shows a total cost of interconnection for this project of about **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** because it eliminated the need for the costly **[TRADE SECRET**

46 CONFIDENTIAL Response to LCA Data Request 1-32.
47 2011 IRP, Attachment C, pages 9-10.
48 CONFIDENTIAL Response to LCA Data Request 1-33.
49 CONFIDENTIAL Response to LCA Data Request 1-33, "CONFIDENTIAL - R81-10 MISO ND DPP5 TWFF 10252010.pdf", page xiii.

DATA BEGINS _________ TRADE SECRET DATA ENDS][50] Since this report is dated January 13, 2011 (before the completion of the 2011 IRP), the Company should still have considered it.

Q. Please describe the IL CT Proposal.

A. An offer was made by **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** in response to MDU's 2010 RFP to provide capacity and energy **[TRADE SECRET DATA BEGINS _________ TRADE SECRET DATA ENDS]** Per MDU, this offer was modeled in EGEAS and was selected as one of the least-cost supply options from the suite of offers received in response to the RFP.[51]

Q. Why did the Company not include this resource in its IRP modeling analysis?

A. It was rejected for several reasons related to the fact that the units were in an area very likely to be an external capacity zone relative to MDU's load. An MDU presentation identified the following concerns:

1. "Concerned with deliverability of capacity under proposed MISO Resource Adequacy construct.
2. External capacity zone. Concerned with differences in zonal pricing for generator outside MDU pricing zone if need to serve MDU load.

[50] R811-10 – DPP Cycle 5 MT/ND Final Report; See also response to LCA Data Request 2-6.
[51] 2011 IRP, Attachment C, page 9.

3. Confirmed with affect [sic] if MDU would withdraw from MISO."[52]

Q. Do you agree the project should have been removed from consideration?

A. No. Due in large part to the lower capacity charge the IL CT units had a significantly lower fixed charge than other options in the 2011 IRP. While there is some risk related to the fact that MISO has not finalized its new Resource Adequacy construct, there are several mitigating factors that MDU should have considered in evaluating this offer. I will address each of the points made in the MDU analysis of the IL CT proposal individually.

Q. What factors should be considered with regards to the deliverability concern raised in the Company's analysis?

A. With regards to deliverability, while it is theoretically possible that MDU could have difficulty qualifying the IL CTs for PRCs in its zone, it seems unlikely. Power generally flows from West to East in MISO, and there is a general demand for more power from the West, especially for wind to meet Eastern state renewable portfolio standards ("RPS"). This suggests that the export constraints that states such as Iowa and Illinois experience relate more to interfaces to the East than the West. It is likely that capacity in Illinois would be available to meet need in North Dakota, especially considering the general plans that MISO has to increase transmission capability between those two areas.

[52] CONFIDENTIAL Response to LCA Data Request 1-32, "CONFIDENTIAL - Analysis 2010 Capacity and Energy Supply RFP - 13 Dec 2010.pdf", slide 19. I have asked for further explanation of these reasons in CONFIDENTIAL LCA Data Requests 5-2, 5-3 and 5-4, but have not yet received responses at this time.

As part of its transmission planning process, MISO has released a list of 2011 Candidate Multi-Value Projects ("2011 MVPs") aimed at reducing congestion in key areas. Many of the 2011 MVPs would enhance specific bottlenecks that currently exist between North Dakota and Eastern Illinois. However, MDU has stated that these plans do not impact its capacity deliverability analysis, indicating that its only consideration is the number of Local Resource Zones ("LRZs") that must be traversed.[53] In my opinion, this is an overly simplistic analysis of capacity deliverability.

Q. What factors should be considered with regards to pricing variations between zones?

A. There are two kinds of pricing separation that need to be discussed related to the IL CTs. First, assuming that some sort of locational capacity market is adopted as per MISO's filing, it is possible that capacity prices could be different in the West zone, where MDU load will presumably be located, and the Illinois zone, where the IL CT units will presumably be located. This could lead to a situation where, even if the units qualify to meet MDU's PRMR there could be a discrepancy between the price load pays and the price the IL CT units receive, leading to the IL CT units not being a full hedge against market costs. This type of price separation, however, should be fully mitigated by MISO's stated plans to allow LSE's to Self-Schedule in part or in full. The other form of price separation relates to the price of energy at the IL CT's node versus the price of energy that MDU load will pay during those hours IL CTs are running. While this difference would lead to differing prices for cost to load and revenue, historical LMPs

[53] Response to LCA Data Request 4-7.

suggest that the difference represents an *added* value to MDU, not a cost (see Exhibit RSH-8). Additionally, the total dollar value of this item should be small on an annual basis due to the fact that the CTs would be expected to run no more than 5% of the time.

Q. What factors should be considered with regards to potential issues with the IL CT should MDU choose to leave MISO?

A. While the bid was for a 20–year contract, the bidder did offer to "discuss a shorter term", which could have been used to reduce the risk that MDU would still be a party to this PPA while no longer a member of MISO. Additionally, MISO has a stated objective of "development of procedures that will facilitate and not restrict the ability of resources that are located in the MISO Region to be available for use by neighboring regions to meet their capacity needs."[54]

X. SUMMARY OF MDU EGEAS ANALYSIS

Q. Have you examined the EGEAS results the Company relied upon to select the portfolio of resources for its IRP?

A. Yes. The EGEAS run results were provided in response to LCA Data Request 1-22.

Q. Have you reviewed the fuel cost assumptions used in the Company's analysis?

A. Yes. Exhibit RSH-3 provides a graphical comparison of the Company's base case, low case, and high case annual average prices for natural gas, compared to

[54] AFFIDAVIT OF TODD P. HILLMAN ON BEHALF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. (TAB F of the MISO filing dated 7/20/2011), page 23.

the 2011 natural gas price forecast contained in the Annual Energy Outlook ("AEO") issued by the Energy Information Agency, a part of the Department of Energy. While the AEO base case forecast is approximately equal to the Company's low case, the price trends are similar. I accept the Company's forecast of natural gas prices for the purposes of this proceeding.

Q. Have you reviewed the Company's assumptions regarding natural gas supply for the proposed 88 MW CT unit?

A. The testimony of Mr. Morman on behalf of MDU describes the Company's proposed natural gas procurement strategy. I reviewed this and also examined how natural gas costs were modeled in EGEAS.

Q. Please describe the proposed natural gas supply strategy.

A. The Company proposes to construct its own lateral pipe from the Heskett site in Mandan to the Northern Border Pipeline. The cost of this lateral has been included in the capital costs for the proposed CT. Thus, the delivery point for natural gas supplies will be the point on the Northern Border Pipeline where the Company's lateral interconnects. The Company has stated that there is no firm capacity available on the Northern Border Pipeline, so the Company proposes to purchase natural gas commodity at the planned delivery point from marketers who already have secured pipeline capacity. The Company claims that this approach will result in lower natural gas costs when compared to procuring newly-added firm transportation capacity and arranging commodity purchases at an alternative delivery point closer to the gas supplies, because marketers will have a portfolio of customers and supplies and will be able to integrate the supplies to the 88 MW CT with the other supply obligations and take advantage of diversity of demands.

Q. How did MDU model gas supply costs in EGEAS?

A. EGEAS uses as inputs a forecast of future delivered prices for all fuels, including natural gas. Specifically, annual prices for delivered natural gas supplies are assumed to apply to each unit burning that fuel. That is to say, all units that burn natural gas are assumed to have the same annual fuel price input in EGEAS.

Q. What is your assessment of the Company's natural gas supply strategy?

A. I believe that the proposed fuel procurement strategy for the 88 MW CT is generally reasonable, especially for the type of peaking generating unit being proposed here. I was able to confirm that there is currently very little to no transportation capacity available on the portion of the Northern Border Pipeline where the proposed lateral will interconnect. Peaking units such as this proposed 88 MW CT should not be dispatched very frequently, mainly only during high peak hours. Therefore, it does not make economic sense to acquire firm transportation and pay for that capacity all year long while operating this plant only several hundred hours per year at most. There are sufficient marketers in this section of the country to help ensure competitively priced supplies. It should be noted that the detailed agreements that would implement this procurement strategy have not been provided and probably would not be negotiated until the plant was under construction and nearing completion. A full evaluation of the proposed procurement strategy would require a review of these contracts, but such a review is not possible at this time.

Q. Do you agree with the method of modeling of fuel prices in EGEAS?

A. In my experience, what was done in EGEAS is typical of virtually all long-term planning models. In real life, different generating units will have different supply arrangements that may have been negotiated at different times. Some will rely upon longer-term contracts and some will utilize shorter-term contracts or even rely upon spot market purchases. Historically, natural gas prices have been volatile, and spot or short-term prices have been both higher and lower than long-term contracts. However, it is not possible to predict with any precision when over the next twenty years spot prices will be higher than long-term prices and when they will be lower. For this reason, it is common in utility planning models to forecast delivered fuel prices as a long-term trend, and apply those prices to all units in the model. Thus, the method employed by the Company in EGEAS to model fuel prices is reasonable.

Q. Please describe the results of the Company's base case analysis.

A. The Company actually ran two base case scenarios: one labeled simply as "base case" and another referred to as "base case DSM." The only difference between the inputs in the two runs was the addition of an extra DSM resource in the latter case.

For the base case in 2015, EGEAS selected the DSM resource from the 2010 RFP and the Big Stone AQCS upgrade. In addition to these resources, EGEAS selected two 43 MW CTs and an 88 MW CT. EGEAS also selected several other resources to meet resource adequacy over time, including wind. In addition, the results show that the Company relied on MISO energy purchases for 11.4% of energy needs over the study horizon and 12.9% of energy needs in 2015.

The results of the resource selections in 2015 were similar for the base case DSM run. EGEAS continued to select the DSM resource from the 2010 RFP and the Big Stone AQCS upgrade. But instead of selecting two 43 MW CTs and an 88 MW CT in 2015, it selected two 88 MW CTs.

Q. Do you have any concerns with the Company's results using base case assumptions?

A. I have several concerns. The Company allowed only one combined cycle plant to be built over the entire planning scenario. I also note that CT units, both existing and new, have extremely high capacity factors, as shown in Exhibit RSH-5. These extremely high capacity factors for peaking units would normally cause EGEAS to select a much more efficient combined cycle unit instead. This excessive reliance on peaking units may indicate issues with the EGEAS model inputs. Also, I note again that the model runs were set to ignore AFUDC, causing an overall bias toward building new resources.

Q. What sensitivities did the Company evaluate?

A. The Company examined nine different sensitivity scenarios:

- $30/ton Carbon Tax
- $50/ton Carbon Tax
- High Natural Gas Prices
- Low Natural Gas Prices
- High Environmental Cost

- High Load Growth
- Low Load Growth
- High CT Cost
- High Big Stone AQCS Cost

Q. How did EGEAS's resource build-outs vary across these sensitivity scenarios?

A. Figure 6 below summarizes the EGEAS resource build-outs for all the different cases over the entire study period, omitting the DSM and Big Stone resources that were always selected. Exhibit RSH-4, which is excerpted from Table 3-1 on page 18 of Attachment C of the Company's IRP, provides an annual summary of the Company's EGEAS results.

Figure 6

Total Capacity (MW) Selected by EGEAS from 2011-2030

For Different Planning Alternatives.

(The DSM and Big Stone AQCS resources were always selected and are not shown.)

Scenario	Wind	CT	CC	Baseload	Total
Base Case	100	346	0	0	446
Base Case DSM	100	305	0	0	405
$30 Carbon Tax	310	305	0	0	615
$50 Carbon Tax	310	305	0	0	615
High Natural Gas	150	303	0	30	483
Low Natural Gas	50	346	0	0	396
High Environmental Cost	280	260	0	60	600
High Load Growth	175	778	140	30	1123
Low Load Growth	0	86	0	0	86
High CT Cost	100	303	0	30	433
High BS AQCS Cost	100	303	0	30	433

The only sensitivity scenario in which the 88 MW CT was not selected in 2015 was the low growth scenario, but two 43 MW CTs continued to be selected in that case.

Wind was another resource EGEAS picked to meet 2015 resource needs in several runs. Purchased Wind was selected in 2015 in the $30 and $50 carbon tax, high environmental cost, and high natural gas price sensitivity scenarios. In the $50 carbon tax case, 60 MW of self-built wind was also selected.

CCCT and generic coal resources were not selected to meet resource needs in 2015, but were selected in future years in some cases. Coal was selected in the high natural gas price, high environmental cost, high load growth, high CT cost, and high Big Stone AQCS cost sensitivity scenarios, as is shown in the table above. The CCCT planning alternative was only selected in the high load growth scenario. New purchased capacity based on the Calpine 2010 RFP proposal was never selected by EGEAS.

Q. Do you have any concerns regarding the results of the sensitivity analysis?

A. Yes. I am concerned that the 43 MW aero-derivative CT was so frequently selected. As an example, in the high load growth case EGEAS chose 14 such CTs to be constructed, generally one per year. This creates a resource build-out that is heavily weighted toward new CTs, which make up 62% of all new resource capacity over the study period and leads to MDU relying on CTs for 35% of total generation in 2030. Even in the base case, 21% of generation is assumed to come from CTs by 2030. This indicates the modeling may have been biased toward building new peaking capacity and not units that produce significant amounts of energy.

Q. Are there additional sensitivities that you think the Company should have considered?

A. There are two important scenarios that the Company never considered in its IRP modeling analysis: high coal retirements in MISO due to environmental regulations and the renewal of the wind production tax credit ("PTC").

Q. What assumptions were made regarding retirements of any existing capacity?

A. During the planning horizon of 2011 through 2030, no retirements of existing capacity were assumed. All units existing at the beginning of the study were still in operation at the end of the study.

Q. What did the Company assume regarding the wind PTC?

A. The federal wind PTC is set to expire at the end of 2012. The Company assumed it would expire on schedule.[55]

Q. Was this assumption reasonable?

A. It is impossible to predict future federal energy policy with absolutely certainty. However, given that the wind PTC has been extended in the past, it would have been helpful to analyze a scenario in which it was extended through 2015 to see the impact on self-built wind resource selections in EGEAS. It should be noted that in the Big Stone AQCS proceeding, in which MDU was a participant, the PTC was assumed to be extended.

[55] Response to LCA Data Request 1-39.

XI. ALTERNATIVE ANALYSIS

Q. Did you request that the Company performed any EGEAS analyses with alternative assumptions?

A. Yes. In discovery request 3-3, the Company was requested to re-run the EGEAS software with the following changes in assumptions.

a. Add two to three additional planning alternatives:
    i. A representation of the 150 MW wind farm offered in the 2010 RFP, but later rejected due to high transmission interconnection costs. The representation should use the exact same assumptions that were used in the EGEAS runs used to select the least-cost options from the RFP.
    ii. A representation of the simple cycle combustion turbine proposal in Illinois offered in the 2010 RFP, but later rejected due to deliverability concerns. The representation should use the exact same assumptions that were used in the EGEAS runs used to select the least-cost options from the RFP.
    iii. If it was not modeled this way in the 2010 RFP EGEAS runs, add an alternative that represents the 176MW Illinois CT proposal.
b. Remove the TransCanada (Keystone XL Pipeline) load, both sales and peak load, from MDU's load forecast.
c. Lower the forced outage rate for the 43 MW combustion turbine planning alternative from 22.31% to 6.45%.
d. Lower the capital cost assumption for the self-built wind planning alternatives from $2,400/kW to $1,750/kW.
e. Assume the federal production tax credit for wind resources is extended through 2020.
f. Set the fixed O&M cost for the purchased wind energy planning alternatives to $0.
g. Set the variable O&M for the combined cycle planning alternative to $3.00/MWH
h. Include all changes listed in parts a through g.

The Company stated that it made all of these requested changes except from the load reductions in item b) above. Exhibit RSH-6 provides a summary of the results of a single run performed by the Company with these changes.

Q. What do these results show?

A. As shown in Exhibit RSH-6, with all assumption changes, no new CT unit is selected in 2015. In the Company's base case analysis, the NPV of EGEAS costs over the entire planning horizon was $3,724 million. With the changes in assumptions requested in data request 3-3, the NPV of these costs decreases to $3,330 million, or a reduction of $394 million. If the ND wind project and the purchase from the IL CTs were removed, the NPV is $3,630 million. Thus, the savings due solely to the addition of these two resources equals $300 million, and savings due to the other changes is $94 million.

Q. What do you conclude from these results?

A. These results show that there is a lower-cost scenario than the solution proposed by the Company. Had the Company included the ND wind project and the IL CT purchase, both of which were projects bid into the 2010 RFP, the 88 MW CT for which the Company seeks an ADP and a CPCN would not have been selected. It should also be noted that the IL CT purchase is for 176 MW, which addresses all of the Company's projected need in 2015, and avoids the additional solicitations in 2012 that the Company stated they would pursue. As I discussed in Section IX of my testimony, in my opinion it was unreasonable for the Company to eliminate these resources from consideration in the 2010 RFP, and by extension the 2011 IRP analysis.

Q. Can you provide a side-by-side cost comparison of the IL CT purchase and the 88 MW CT proposed by MDU?

A. Confidential Exhibit RSH-7 contains such a comparison. The data used to prepare this Exhibit came from the 2010 RFP and the Company's base case EGEAS runs in the 2011 IRP. Specifically, I used the cost parameters for the IL CT purchase that were submitted in the 2010 RFP.[56] The cost parameters for the 88 MW CT were taken from EGEAS inputs. To ensure compatibility in the comparison, I determined the total annual costs for the 176 MW IL CT purchase and for two 88MW CT units so that each alternative provided the same 176 MW of capacity. I also assumed a capacity factor of 5%, which was the EGEAS capacity factor in 2015 for both resources.

As shown in Confidential Exhibit RSH-7, the IL CT purchase would cost $242 million from 2015 to 2030. Over this same time period, two 88 MW CTs would cost a total of $411 million, or 70% ($169 million) more than the IL CT purchase. Confidential Exhibit RSH-7 also shows that in the first year, the rate increase associated with the two 88 MW CTs would be $17 million higher than if the IL CT purchase had been selected. This is further evidence that the 88 MW CT proposed by MDU is not the least-cost option.

[56] Response to LCA Data Request 1-31.

XII. CONCLUSIONS AND RECOMMENDATIONS

Q. Would you summarize your findings with respect to the issues before the Commission in this proceeding?

A. My findings are as follows:

- I find that the Company's load forecast methodology and results are generally reasonable, and combined with the expiration of certain power purchases, demonstrate a need for new capacity.
- The Company's analysis ignores certain resources identified in the 2010 RFP that are feasible and when analyzed result in considerable savings relative to the proposed CT unit.
- There are other feasible, more economic alternatives to the proposed project. The Company has not demonstrated that its proposal is the least-cost option for North Dakota ratepayers.
- Because the Company has not selected the least-cost alternative, its request for an ADP and a CPCN should not be granted.

Q. Does this conclude your testimony?

A. Yes. It should be noted that at the time of the filing of this testimony, some discovery responses may still be outstanding or in the process of being reviewed. I will supplement this testimony as appropriate to reflect any new information received subsequent to filing.

La Capra Associates

PU-11-395/396 Exhibit RSH-1

Richard S. Hahn

Principal Consultant

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn also has extensive knowledge and experience in both the energy and telecommunications industries. He has testified on numerous occasions before the Massachusetts Department of Public Utilities, and also before FERC.

SELECTED EXPERIENCE – LA CAPRA ASSOCIATES

- Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont.
- Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site.
- Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah.
- Served as a principal advisor and key team member in La Capra Associates' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont.
- Reviewed and evaluated the construction of and cost recovery for a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.
- Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.
- Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
- Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for Pennsylvania Electric Distribution Companies.

- Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.
- Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.
- Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.
- Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.
- Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.
- Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.
- Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light and Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan
- Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan.
- Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.

- Conducted a review of Massachusetts electric utilities' proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Served as a key member of a La Capra Associates Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to several existing coal-fired power plants in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony in three separate proceedings before the Public Service Commission of Wisconsin.
- Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the La Capra Associates Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.
- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.
- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant powerplant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.

- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing powerplants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.
- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.
- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.
- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.
- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

- Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

- Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

- Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.
- Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.
- Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.
- Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

- Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.
- Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

- Promoted and sold residential and commercial energy-efficiency products and customer service programs.
- Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.
- Designed and marketed energy-efficiency programs.
- Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

- Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases
- Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.
- Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.
- Negotiated and administered over 200 transmission and purchased power contracts.

- Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.
- Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

La Capra Associates, Inc.	**Boston, MA**	
Principal Consultant		2004 – present
Advanced Energy Systems, Inc.	**Boston, MA**	
President and COO		2001-2003
NSTAR Steam Corporation	**Cambridge, MA**	
President and COO		2001-2003
NSTAR Communications, Inc.		
President and COO		1995-2003
Boston Edison Company	**Boston, MA**	
VP, Technology, Research, & Development		1993-1995
VP, Marketing, Boston Edison Company		1991-1993
Vice President, Energy Planning, Boston Edison Company		1987-1991
Manager, Supply & Demand Planning		1984-1987
Manager, Fuel Regulation & Performance		1982-1984
Assistant to Senior Vice President, Fossil Power Plants		1981-1982
Division Head, Information Resources		1978-1981
Senior Engineer, Information Resource Division		1977-1978
Assistant to VP, Steam Operations		1976-1977
Electrical Engineer, Research & Planning Department		1973-1976

EDUCATION

Boston College		Boston, MA
Masters in Business Administration	1982	
Northeastern University		Boston, MA
Masters in Science, Electrical Engineering	1974	
Northeastern University		Boston, MA
Bachelors in Science, Electrical Engineering	1973	

PROFESSIONAL AFFILLIATIONS

Director, NSTAR Communications, Inc.	1997-2003
Director, Advanced Energy Systems, Inc.	2001-2003
Director, Neuco, Inc.	2001-2003
Director, United Telecom Council	1999-2003
Head, Business Development Division, United Telecom Council	2000-2003
Elected Commissioner – Reading Municipal Light Board	2005-present
Registered Professional Electrical Engineer in Massachusetts	

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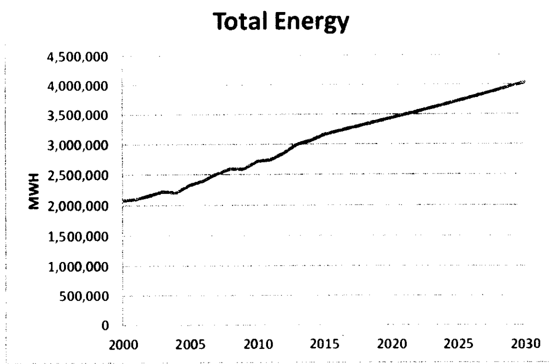
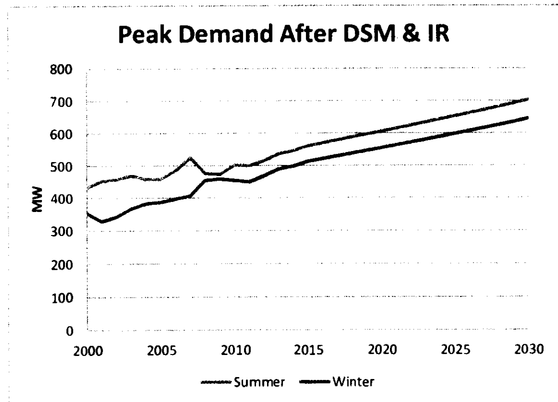
SUMMARY OF MDU LOAD FORECAST

year	Total Energy	% change	Summer Demand before DSM & IR	Interruptible rates	EE	DR	Summer	% change	Winter	% change	anual Load Factor
2000	2,077,579						432.3		353.9		54.9%
2001	2,104,119	1.28%					452.9	4.77%	328.9	-7.06%	53.0%
2002	2,158,431	2.58%					458.8	1.30%	343.5	4.44%	53.7%
2003	2,226,531	3.16%					470.5	2.55%	367.7	7.05%	54.0%
2004	2,204,012	-1.01%					458.4	-2.57%	383.9	4.41%	54.9%
2005	2,327,117	5.59%					459.1	0.15%	387.2	0.86%	57.9%
2006	2,397,793	3.04%					485.5	5.75%	397.2	2.58%	56.4%
2007	2,510,540	4.70%					525.6	8.26%	407.3	2.54%	54.5%
2008	2,596,990	3.44%					476.6	-9.32%	455.0	11.71%	62.2%
2009	2,593,368	-0.14%					473.8	-0.59%	459.6	1.01%	62.5%
2010	2,718,192	4.81%					502.5	6.06%	455.0 [2]	-1.01%	61.8%
2011	2,745,079	0.99%	513.1	7.6	4.2	1.3	500.0	-0.50%	450.3	-1.02%	62.7%
2012	2,849,695	3.81%	532.5	10.3	4.2	1.3	516.7	3.34%	469.4	4.24%	63.0%
2013	3,000,627	5.30%	552.9	10.3	4.2	1.3	537.1	3.95%	489.5	4.28%	63.8%
2014	3,058,976	1.94%	561.9	10.3	4.2	1.3	546.1	1.68%	498.3	1.80%	63.9%
2015	3,157,733	3.23%	577.6	10.3	4.2	1.3	561.8	2.87%	513.5	3.05%	64.2%
2016	3,212,882	1.75%	586.4	10.3	4.2	1.3	570.6	1.57%	521.8	1.62%	64.3%
2017	3,267,300	1.69%	595.1	10.3	4.2	1.3	579.3	1.52%	529.9	1.55%	64.4%
2018	3,322,641	1.69%	603.9	10.3	4.2	1.3	588.1	1.52%	538.2	1.57%	64.5%
2019	3,378,799	1.69%	612.9	10.3	4.2	1.3	597.1	1.53%	546.7	1.58%	64.6%
2020	3,433,624	1.62%	621.8	10.3	4.2	1.3	606.0	1.49%	554.9	1.50%	64.7%
2021	3,489,360	1.62%	630.8	10.3	4.2	1.3	615.0	1.49%	563.2	1.50%	64.8%
2022	3,545,996	1.62%	640	10.3	4.2	1.3	624.2	1.50%	571.7	1.51%	64.9%
2023	3,603,568	1.62%	649.3	10.3	4.2	1.3	633.5	1.49%	580.4	1.52%	64.9%
2024	3,662,045	1.62%	658.7	10.3	4.2	1.3	642.9	1.48%	589.1	1.50%	65.0%
2025	3,721,491	1.62%	668.3	10.3	4.2	1.3	652.5	1.49%	598.0	1.51%	65.1%
2026	3,781,897	1.62%	678	10.3	4.2	1.3	662.2	1.49%	607.1	1.52%	65.2%
2027	3,843,314	1.62%	687.8	10.3	4.2	1.3	672.0	1.48%	616.3	1.52%	65.3%
2028	3,905,749	1.62%	697.8	10.3	4.2	1.3	682.0	1.49%	625.7	1.53%	65.4%
2029	3,969,254	1.63%	708	10.3	4.2	1.3	692.2	1.50%	635.2	1.52%	65.5%
2030	4,033,816	1.63%	718.3	10.3	4.2	1.3	702.5	1.49%	644.9	1.53%	65.5%

[1] source: Table 2-1 of the 2011 IRP

[2] 2010 value is extrapolated





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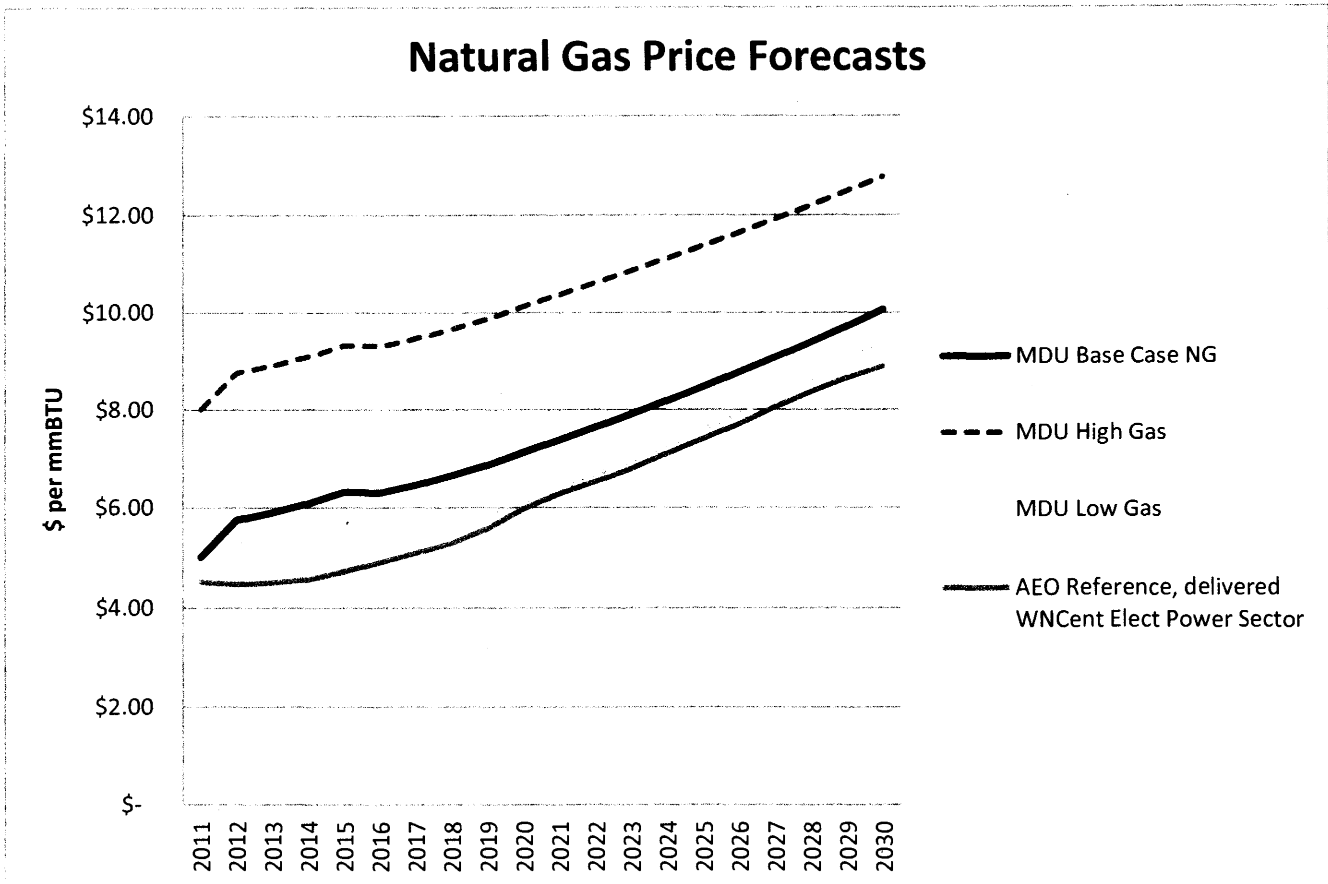

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Table 3-1: Least-Cost Resource Expansion Plans for the Studied Scenarios

Year	Base	Base w/ New DSM Package	Low Gas ($1 down)	High Gas ($3 up)	$30 Carbon Tax	$50 Carbon Tax	$30 Carbon, High Gas, additional Enviranmental	High Capital Cost for Combustion Turbines	High Cost for Big Stone AQCS	Low Growth	High Growth
2011											
2012											2-Purchase
2013	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase	1-Purchase		3-Purchase
2014	2-Purchase	1-Purchase, New DSM	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase	2-Purchase		5-Purchase
2015	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT88, 2-DSM, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS, 1-Wind	2-DSM, 2-CT88, BGS AQCS, 5-Wind	2-DSM, 2-CT88, 5-Wind, BGS AQCS, 2-Wind built	2-CT43, 2-DSM, CT88, BGS AQCS, 5-Wind	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, CT88, BGS AQCS	2-CT43, 2-DSM, BGS AQCS	2-CT88, 2-DSM, BGS AQCS, 2-Wind
2016											CT43
2017											CT43
2018	CT43		CT43	CT43			CT43	CT43	CT43		CT43
2019											CT43
2020	4-Wind	4-Wind	2-Wind	5-Wind	5-Wind, CT43	5-Wind	5-Wind	4-Wind	4-Wind		5-Wind, CT43
2021		CT43				CT43					CT43
2022	CT43		CT43	CT43			1-Base Load	CT43	CT43		CT43
2023					CT43						CT43
2024		CT43					1-Base Load				CT43
2025	CT43		CT43	1-Base Load		CT43		1-Base Load	CT43		CT43
2026											CT43
2027		CT43			CT43		1-Wind Built				CC
2028	CT43		CT43	CT43		CT43	CT43	CT43	1-Base Load		CT43
2029											CT43, Base Load
2030					2-Wind built						CT43
NPV[1]	$3,723.72	$3,615.71	$3,624.26	$3,759.12	$5,014.11	$5,875.53	$5,317.21	$3,809.08	$3,856.56	$2,529.11	$5,990.34

1 - NPV in millions of dollars
*CT43 - 33.4 PRC (43 MW) Combustion Turbine
*CT88 - 82.3 PRC (88 MW) Combustion Turbine
*CC - 132.5 PRC (140 MW) Combined Cycle
*Base Load - 27.7 PRC (30 MW) Coal-fired Generation
*DSM - 12.5 PRC (12.5 MW) Demand Side Management
*BGS AQCS - Big Stone Air Quality Control System
*Wind - 25 MW Wind (Purchased Energy)
*Purchase - 10 PRC (10 MW) Capacity Purchases
*Wind built - 30 MW Wind (Self-built)
*New DSM - New DSM Package