Direct Testimony
James R. Alders

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns

Docket No. E002/CI-13-754
Exhibit___(JRA-1)

Resource Planning
Project Economics

October 18, 2013

Table of Contents

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James R. Alders. I am a Regulatory Consultant for Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"). The Company is a wholly-owned utility operating company subsidiary of Xcel Energy Inc. My business address is 414 Nicollet Mall, Minneapolis, MN 55401.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCES.

A. I graduated from the University of Minnesota with a Bachelor of Science degree in Urban Studies in 1973 and from the University of St. Thomas with a Master of Business Administration degree in 1991.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCES IN THE AREAS OF RESOURCE PLANNING AND INFRASTRUCTURE PERMITTING.

A. I have been employed by the Company for more than 37 years. Since 1994, I have been extensively involved in development of the Company's resource plans and represented the Company before state and federal regulators in various resource planning and resource acquisition proceedings. In this capacity, I have been responsible for regulatory filings in Minnesota, South Dakota and North Dakota to present the Company's resource plans and to support specific resource acquisitions, certificates of need, power plant siting, and transmission routing proceedings.

Q. DO YOU HAVE EXPERIENCE DIRECTLY RELATED TO THE COMPANY'S NUCLEAR PROGRAM?

A. Yes. I have been employed in various positions responsible for obtaining necessary permits, including certificates of need, for the Company's Monticello and Prairie Island nuclear power plants. I was actively involved in seeking the certificates of need for on-site spent-fuel storage for both sites as well as certificates of need and related permits associated with the extended operating licenses for both facilities. I was actively involved in the Company's efforts to obtain a certificate of need for the Monticello Extended Power Uprate.[1]

II. SUMMARY AND OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Testimony is to support the Company's efforts to provide information to the Commission pertaining to our life-cycle management ("LCM") and extended power uprate ("EPU") work at Monticello (the "LCM/EPU Program" or the "Program"). Company witness Mr. Timothy J. O'Connor provides a comprehensive description of the Program. My testimony supports that description by providing analysis in the following specific areas:

- Xcel Energy's State regulatory efforts to obtain a renewed license to operate Monticello through 2030;
- The resource planning context that influenced how we implemented the LCM/EPU Program and drove our decision to pursue multiple

[1] *Petition for a certificate of need for the Monticello Nuclear Generating Plant for Extended Power Uprate,* Docket No. E002/CN-08-185, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT (Jan. 8, 2009).

activities in parallel to meet the forecast demand and to minimize energy costs at the time;

- The certificate of need process for obtaining Commission authority to construct the EPU upgrades;
- The Strategist modeling to assess the value of Monticello to our system as a long-term resource; and
- The prudence of the economic decision to continue with the Program throughout as we responded to evolving circumstances.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Life Extension Issues: First, I provide context around the Company's decision to seek and obtain operating license extensions for our nuclear fleet and to invest capital to ensure the long-term safe and reliable operation of our nuclear plants. Monticello's location and the robust transmission system around it provide significant reliability benefits to our customers and maximize the use of existing infrastructure. Nuclear generation acts as a valuable carbon-free hedge against natural gas prices and potential future carbon regulations.[2] It contributes to the diversity of our fuel mix and reduces our reliance on market energy.

Resource Planning Issues. Second, I outline the Company's resource planning challenges and decisions during the timeframe that the LCM/EPU Program

[2] The importance of this carbon-free hedge is highlighted by the October 5, 2013 motion by a group of clean energy advocates to reopen the Commission's environmental externalities docket, to update the externality values to be applied to CO_2 and other emissions for use in resource decisions. Any increase in the value ascribed to CO_2 will magnify the value of nuclear as an important part of our portfolio. *Clean Energy Organizations' Motion to Update Externality Values for Use in Resource Decisions,* Docket No. E-999/CI-93-583, ORDER ESTABLISHING ENVIRONMENTAL COST VALUES (Jan. 3, 1997) and ORDER AFFIRMING IN PART AND MODIFYING IN PART ORDER ESTABLISHING ENVIRONMENTAL COST VALUES (July 2, 1997)

was being developed and implemented. I describe how the Company's demand forecast showed a need for a significant amount of baseload capacity in the 2004-2009 timeframe. This sustained period of strong demand growth made it critical that we identified new resources for our system during the planning horizon. During this same timeframe, the Company identified the potential to increase capacity at Monticello and other baseload plants as one way to add capacity to meet the forecast demand. During this period of relatively higher natural gas and renewable resource prices, baseload energy resources were substantially more valuable than today. Because of the timing of the capacity need at that time, it was necessary for Xcel Energy to move forward with the LCM/EPU Program on multiple tracks simultaneously in order to complete all the necessary activities in time to satisfy part of that need. We also wanted to achieve the benefits of the uprate for the extended license life and to optimize our investment over the plant's extended life. This meant that we needed to commit capital prior to obtaining all necessary regulatory approvals.

<u>EPU certificate of need</u>. Third, I will describe the certificate of need process undertaken to seek Commission authority to construct the EPU upgrades in support of increasing the capacity at Monticello by approximately 71 MW. Because of the increased demand shown in our resource plan forecast, we proceeded to seek a certificate of need to add capacity at Monticello (as well as at two other plants). The Commission granted the requested certificate of need on the basis that the Company needed to add resources and the cost of the incremental megawatts at Monticello was a cost-effective option based on the alternatives analysis that was done at the time.

Strategist Modeling. Fourth, I will describe (i) the Strategist modeling results supporting our decisions to develop and implement upgrades to Monticello, (ii) ratepayer value in the LCM/EPU Program, despite delays, rising costs, and changed economic conditions, and (iii) how the circumstances at Prairie Island are distinguishable from our Program at Monticello.

This modeling work shows that, while the upgrades were more expensive than we planned, the Monticello power plant remains a cost-effective resource for our customers.

- With the $665 million investment, on a total plant basis, Monticello was cost-effective under 2008 modeling conditions. Thus the additional costs would not have changed the overall value of this resource to our customers at the time.
- Even under 2013 conditions (including lower forecast demand and much lower natural gas prices) Monticello remains a valuable resource compared to a combined-cycle natural-gas plant.
- Our analyses show that, as we invested in the LCM/EPU Program over the five-year installation schedule, our investment remained in the best interests of our customers. This implementation analysis takes into account the capital already invested in the Program each year and the investment remaining to complete the upgrades in order to assess whether it was prudent to continue with the implementation.
- Even without taking into account our sunk costs, the LCM/EPU Program continued to make sense despite reduced demand forecasts and falling natural gas prices in the 2010-12 timeframe.
- The cost of the incremental 71 MW is more difficult to assess as the Company did not segregate its costs in that way. Nevertheless, we

provide modeling results on two hypothetical scenarios: (i) an avoided cost analysis recognizing that 22.0 percent of the costs can be characterized as "avoidable EPU" and 78.0 percent can be seen as "unavoidable LCM" that would have been incurred anyway, and (ii) the 41.6 percent (EPU)/58.4 percent (LCM) split used in the 2008 certificate of need. When specific avoidable costs are attributed to the incremental 71 MW, the cost of those megawatts is generally higher than a natural gas alternative, although this review fails to account for the value of the LCM improvements to the plant as a whole.

III. REGULATORY CONTEXT

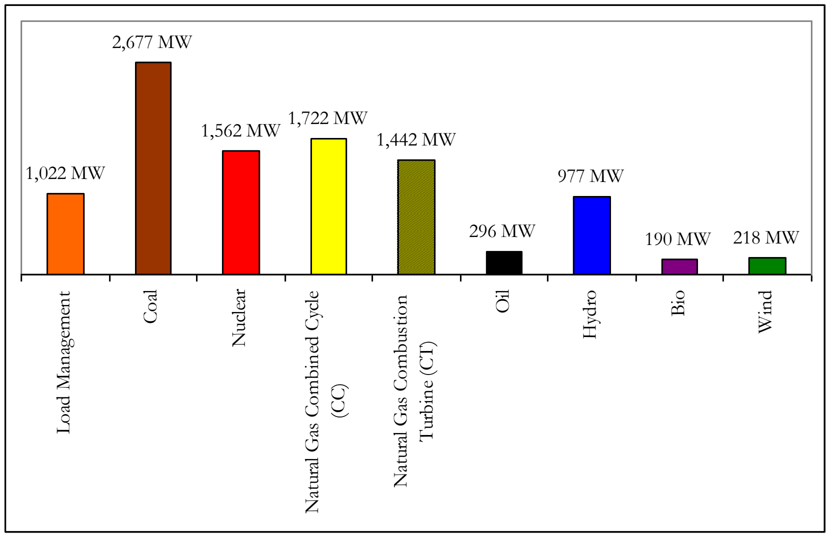
A. The Contribution of Xcel Energy's Nuclear Fleet

Q. PLEASE DESCRIBE THE COMPANY'S GENERATION PORTFOLIO?

A. Xcel Energy has been successful in developing a well-diversified portfolio of generation resources. Nuclear, coal, natural gas, wind, hydro, biomass, and conservation all play valuable roles in providing our customers with low cost energy. Because of our diversification, our rates are not susceptible to fluctuations in the cost of any one type of fuel or generation resource.

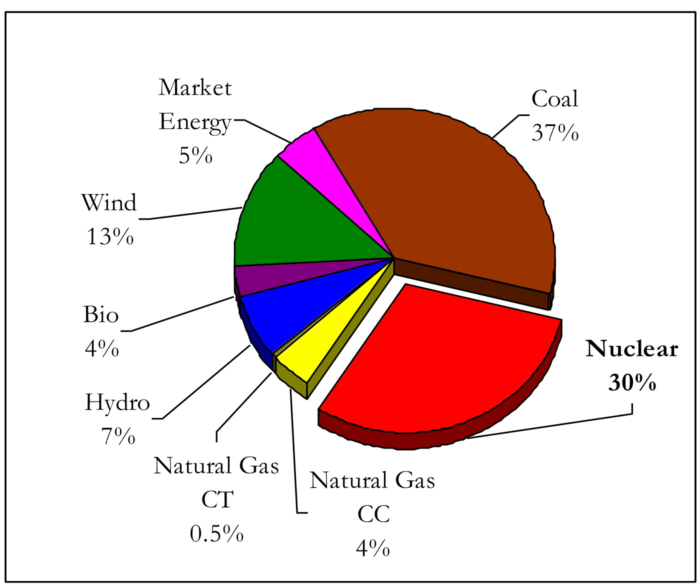
One can measure nuclear power's contribution to Xcel Energy's generation fleet in two ways. First is a capacity perspective that measures each generating resource's contribution to meeting our peak customer demand, which typically occurs on a hot summer weekday. Figure 1 shows that on a capacity basis our nuclear fleet is similar in size to our coal and natural gas resources.

Figure 1. Xcel Energy Capacity Mix



The second method of measuring nuclear power's role in our portfolio is to look at total annual generation from each type of resource. The energy mix shows that nuclear plays a much larger roll. As can be seen in Figure 2, nuclear is second only to coal in providing energy to the system.

Figure 2. Xcel Energy Annual Energy Mix



Q. PLEASE PROVIDE A SUMMARY OF XCEL ENERGY'S NUCLEAR POWER GENERATION CAPABILITY.

A. Xcel Energy has three nuclear power units located at two plants. Information about these two plant is provided in Table 1.

Table 1. Xcel Energy's Nuclear Power Units

Unit	Size	Original License Expiration	Extended License Expiration
Monticello	600 MWe	September 30, 2010	September 30, 2030
Prairie Island Unit 1	550 MWe	August 9, 2013	August 9, 2033
Prairie Island Unit 2	550 MWe	October 29, 2014	October 29, 2034

When the EPU license amendment is granted by the Nuclear Regulatory Commission ("NRC"), this total will increase to 1,771 MW (reflecting the addition of 71 MW from the uprate work at Monticello).

Q. DOES NUCLEAR POWER PROVIDE VALUE TO CUSTOMERS?

A. Yes. Nuclear provides significant value to customers in a variety of ways.

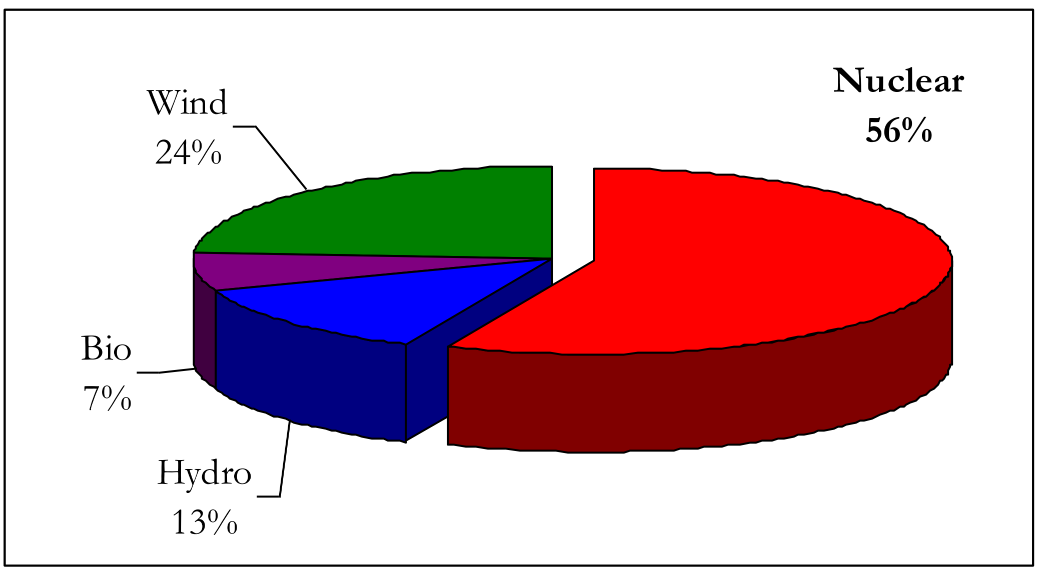
First, nuclear generation provides baseload generation resource with low incremental fuel costs and with no fossil-fuel-related emissions. Table 2 presents the smokestack emissions avoided by nuclear power in 2012.

Table 2. Emissions Avoided by Nuclear Power (2012)*

	Sulfur Dioxide (Short Tons)	Nitrogen Oxides (Short Tons)	Carbon Dioxide (Metric Tons)
Nationally	**996,611**	**466,559**	**569,740,000**
Minnesota	**26,176**	**13,354**	**11,670,000**
*Source: Nuclear Energy Institute - Emissions avoided by nuclear power are calculated by using regional fossil fuel emissions rates from the Environmental Protection Agency and plant generation data from the Energy Information Administration			

Second, nuclear generation from the Monticello and Prairie Island plants results in reduced CO_2 emissions. Figure 3 shows the contribution of nuclear in providing carbon-free energy.

Figure 3. Carbon-Free Energy Resource



Third, nuclear generation contributes to fuel diversity in our fleet. Thus, it provides the Company and its customers a valuable hedge against potential increases in fossil fuel costs.

B. The Contribution of Monticello

Q. WHAT OTHER BENEFITS DO RETAINING 671 MW OF NUCLEAR POWER FROM MONTICELLO THROUGH 2030 PROVIDE?

A. Retaining Monticello as a part of our resource portfolio provides quantitative benefits of 671 MW of reliable baseload capacity and low incremental fuel costs. Later in my testimony I provide a discussion of the modeling work we undertook to describe these benefits. There are also qualitative benefits to retaining nuclear generation at Monticello.

First, Monticello is strategically located only 30 miles from our largest load center. This location and the robust transmission system that developed around this and other local generation provide significant reliability benefits to our customers. Maximizing the use of existing infrastructure is an efficient way to provide value to customers. Through our life-cycle management program, we have upgraded Monticello to ensure that these resources remain available to customers at least through 2030. It is in our customers' interest to maintain these assets for the long term.

Second, the environmental regulations applicable to fossil-fuel generation have been evolving. Indeed, dramatic changes in coal environmental regulations and the potential for more changes present challenges to existing coal generation and make it almost impossible to commit to a new coal plant resource at this time. If nuclear is replaced in the current environment it would be with natural gas generation to be operated as a baseload resource. The fuel diversity offered by nuclear generation is an important part of the Company's generation mix.

Another benefit is that nuclear generation acts as a hedge against fuel prices and potential future carbon regulations. If the Company had not pursued the 20-year license renewal and closed Monticello in 2010, future levels of natural gas consumption and Midcontinent Independent System Operator ("MISO") market purchases would be higher, creating higher cost uncertainty for our customers. We project that replacing 671 MW of nuclear generation with natural gas generation would increase our annual natural gas usage by 19 bcf or 45 percent. It would also increase our market purchases by approximately 850 GWh or 61 percent.

Fourth, retaining Monticello creates a hedge against potential federal CO_2 legislation. It is unclear when significant CO_2 legislation might be imposed and what form it may take (cap and trade, carbon tax, strict annual limits), but retaining Monticello's 600 MW (through 2013) and 671 MW (from 2014 through 2030) will add 4,800-5,400 GWh of carbon-free energy annually reducing our annual CO_2 emission by approximately 2.8 million tons or 14 percent, compared to a scenario in which Monticello is replaced by natural gas generation. This will reduce our exposure to carbon regulation and will lower the cost of compliance with any CO_2 goal or target level.

To illustrate the benefit of retaining Monticello, Table 3 shows the base case volumes of natural gas, market purchases and CO_2 emissions – and the deltas against these factors for the studied projects.

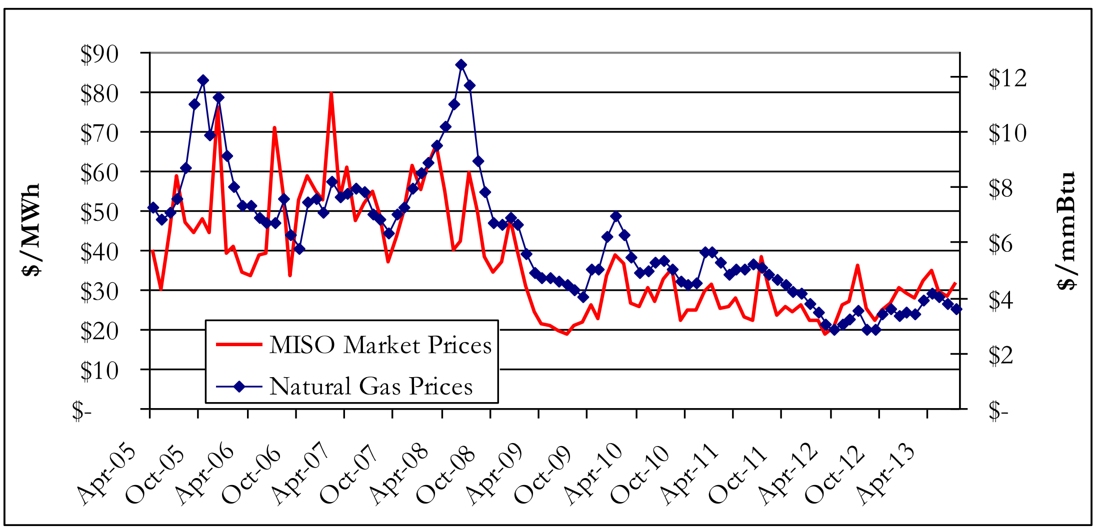
Table 3. Monticello's Hedge Value

Total System 2015-2030	Natural Gas *bcf*	Market Purchases *GWh*	CO2 *Million tons*
Monticello in service at 671 MW in 2014	844	27,774	412
Natural gas generation replaces Monticello in 2014	1,225	44,855	468

Q. WHAT IMPACT DO CURRENT NATURAL GAS PRICES HAVE ON YOUR ANALYSIS?

A. Although current prices for market energy and natural gas are low, historically the price of these energy resources has been extremely volatile. Nuclear generation provides a relatively stable hedge against historically-volatile natural gas prices, as shown in Figure 4.

Figure 4. Gas Prices and Market Prices



IV. LICENSE EXTENSION

Q. WHEN DID THE COMPANY BEGIN TO EVALUATE OPERATION OF ITS NUCLEAR FLEET BEYOND THE EXPIRATION OF THEIR INITIAL LICENSES?

A. We originally obtained 40-year operating licenses from the NRC for each of the nuclear units. While this is a significant period of time, by the mid-1990s it was time to begin thinking about the implications of closing our nuclear units to provide sufficient lead time to replace a major source of baseload generation.

We recognized that closing the nuclear plants after 40 years and replacing them with new baseload generation would create excess customer costs compared with relicensing the nuclear plants and undertaking the work necessary to keep them in good working order for their extended license period. Our assessment of the plants was that the cores and reactors were sound, and that the power-plant side or "secondary systems" were in reasonably good shape and could be repaired or replaced to support extended operations.

Many of the plant-side systems at a nuclear plant are similar to the operating equipment of other technologies that produce power from steam, and could be used for extended periods under appropriate circumstances. We reasonably believed that repairing or replacing those secondary systems as necessary to maintain safe and reliable operation was the appropriate approach to keeping nuclear generation as a long-term viable option for our customers.

Q. DID XCEL ENERGY EVER CONTEMPLATE CLOSING THE NUCLEAR PLANTS?

A. Yes. Prior to 2003 it was not feasible to operate nuclear plants beyond the expiration of the initial 40-year licenses, due to State statutory restrictions against extended reliance on on-site storage of spent nuclear fuel. This had significant implications on our investment plans. Thus, we deferred some long-term capital projects that may have been appropriate in the 1990s and early 2000s to support operations beyond the original operating license. Rather, we focused on those projects necessary to ensure safe and reliable operation through the end of the initial license.

Q. HOW DID CIRCUMSTANCES CHANGE IN 2003?

A. In 2003, Minnesota law was changed, providing Xcel Energy with the right to seek certificates of need supporting the ongoing operation of the nuclear units. *See* Minn. Stat. §§ 116C.83 and 216B.243, subd. 3b. This legislation essentially provided the Commission with authority to consider whether continued operation of the nuclear units was in the best interests of customers.

The legislation essentially provided the Commission with the discretion to consider the on-site storage issue as part of a broader assessment of the potential value of extending the operating licenses. Thus, in order to support continued operations of the nuclear units, it was necessary for the Company to be able to construct and operate sufficient on-site spent-fuel storage at each plant to support continued operations. Without on-site spent fuel storage capability, it would have been impossible to continue operating the units beyond their initial licenses.

Q. HOW DID XCEL ENERGY RESPOND TO THE 2003 LEGISLATION?

A. The Company began to focus on the potential value to our customers of extending the nuclear operating licenses. The Company recognized that we were behind in our capital improvement program and that we needed to catch up in terms of obtaining the license renewal. During the period when Minnesota law effectively precluded a renewed license, Xcel Energy's capital program at Monticello focused on maintenance and repairs to keep the plant working safely and efficiently but did not include the types of large and long-term capital projects that would be needed to support an additional 20 years of operation. We realized that we would need to multi-track our efforts to be sure we could get all of the work done that is necessary to ensure the long-term safe and reliable operation of these plants.

Q. WHAT ARE THE COMPANY'S OBLIGATIONS WHEN CONSIDERING A NUCLEAR PLANT LIFE EXTENSION?

A. It is our primary responsibility to ensure that our nuclear facilities are at all times safe and are operated and maintained in a way that promotes public safety. As part of this focus on safety, we comply with all required safety margins and other NRC safety requirements. This obligation includes ensuring that the plant addresses aging equipment concerns and replaces components necessary to comply with NRC regulations for the duration of the extended operating license. Generally, the NRC requires that the operator upgrade all aging systems or replaces them to the extent necessary so that the systems can perform their intended function for the entire period of extended operation. This, in effect, creates a requirement to repair or replace worn safety-related systems regardless of other factors.

Q. WHAT WAS XCEL ENERGY'S FIRST STEP IN THE PROCESS?

A. In 2004 we began the process of seeking a 20-year extension of Monticello's original operating license that was scheduled to expire in 2010. This was a major undertaking that required significant investment in the plant to ensure its ability to operate safely and reliably through 2030. We first sought and obtained a certificate of need to authorize on-site spent-fuel storage for Monticello (Docket No. E-002/CN-05-123). This certificate of need paved the way for us to obtain a license extension and to begin the process of determining how best to ensure the long-term operation of our nuclear fleet for the remainder of their extended life.

We believed maintaining operations at our nuclear plants for another 20 years provided ratepayer value compared to the available alternatives. We recognized that larger capital investments would be needed to ensure the long-term safe and reliable operation of the plant to support the license extension. These investments may be necessitated by normal wear and tear, aging equipment concerns, new or evolving regulatory requirements, operating experience at our plants or elsewhere in the industry, as well as obsolescence or new technologies.

We provided the Commission with our analysis showing that it was expected to be cost effective to continue operating Monticello beyond the original license as compared to the coal, natural gas, and natural gas plus wind alternatives that were studied. As part of that analysis we assumed that certain secondary systems at the plant would need to be upgraded or replaced to facilitate an additional 20 years of operation; however, we did not conduct an exhaustive study, and our good faith estimate was based on our prior operating experience at the plant and the NRC environment as it existed at that time.

Our analysis indicated that replacing Monticello with natural gas generation would result in an economic penalty to our customers.[3] The Commission agreed that extending the license for Monticello was appropriate and granted the certificate of need for spent fuel storage.[4]

Q. AT THIS SAME TIMEFRAME, DID THE COMPANY BEGIN ITS EFFORT TO SEEK A LICENSE EXTENSION FROM THE NRC?

A. Yes. On March 24, 2005, while our certificate of need was pending, we filed the license renewal application seeking to renew the license at Monticello, allowing us to continue operations of the plant through 2030. The NRC renewed the operating license for Monticello on November 8, 2006. The timeline and activities undertaken as part of the license renewal process can be viewed on the NRC Website at the following link:
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/monticello.html

[3] *See Application to the MPUC for a certificate of need – Monticello Spent Nuclear Fuel Storage,* Docket No. E002/CN-05-123, APPLICATION FOR A CERTIFICATE OF NEED at 5-2 to 5-9 (Jan. 18. 2005).

[4] *Application to the MPUC for a certificate of Need – Monticello Spent Nuclear Fuel Storage,* Docket No. E002/CN-05-123 ORDER GRANTING CERTIFICATE OF NEED FOR INDEPENDENT SPENT FUEL STORAGE INSTALLATION at 16 (Oct. 23, 2006).

V. RESOURCE PLANNING

Q. WERE OTHER MINNESOTA REGULATORY PROCEEDINGS ONGOING AT THE TIME THAT CONTRIBUTED TO THE COMPANY'S APPROACH?

A. Yes. From 2004 through 2009, the ongoing use of our nuclear fleet was a significant topic of consideration in our resource plan proceedings before the Commission. This debate centered, first, around the value of continued operations of the nuclear units, and, second, around the potential to obtain increased generating capacity from those units to satisfy significant identified baseload capacity needs. In this same timeframe, the Commission was reviewing information about Monticello that showed it to be a cost-effective part of our portfolio for the long-term. This debate continued over two resource plan cycles in 2004-06 and 2007-09.[5]

Q. PLEASE DESCRIBE HOW THE 2004 RESOURCE PLAN PROCEEDING AFFECTED THE CONSIDERATION OF NUCLEAR OPTIONS.

A. In the 2003-2007 timeframe, the Company was experiencing a period of significant load growth. The forecasts at the time showed that we needed a significant amount of new baseload generating capacity in the near-to mid-term. In our 2004 Resource Plan filing, we forecasted an increased demand for up to 1,125 MW of new baseload capacity by 2015.[6]

Development of new baseload capacity requires long planning horizons. As a result, it was important to move forward promptly to build, buy or otherwise secure the generating capacity required to fulfill that obligation.

[5] The *2004 Resource Plan,* Docket No. E002/RP-04-1752, INITIAL FILING (Nov. 1, 2004) ("2004 Resource Plan"), and the *2007 Resource Plan,* Docket No. E002/RP-07-1572, INITIAL FILING (Dec. 14, 2007) ("2007 Resource Plan").

[6] *2004 Resource Plan*, Docket No. E002/RP-04-1752, INITIAL FILING at 1-2 (Nov. 1, 2004).

The 2004 Resource Plan demonstrated that continued operation of our nuclear units through the planning horizon was in our customers' interest since discontinuing use of that capacity would have increased required replacement generation, resulting in higher overall portfolio costs. Our analysis at the time showed that retirement of both Monticello and Prairie Island would cost well over one billion dollars more than continuing to operate them in their existing configurations.[7]

In addition to continued operations of our existing fleet, the demand forecasts at the time pointed to the need for incremental additional baseload capacity. The 2004 Resource Plan proceeding included a robust discussion of alternatives and potential approaches. As part of those discussions, we advised the Commission of the potential for increasing or "uprating" the capacity of Monticello, Prairie Island and Sherco 3 as another source of increased capacity. The Commission concluded that we should pursue the regulatory approvals necessary to move forward with these projects and ordered us to proceed with exploring additional baseload capacity from these existing generators. In its June 2006 Order approving the 2004 Resource Plan, the Commission required the Company to file for any required Commission review or approval for these upgrades promptly.[8]

[7] *2004 Resource Plan,* Docket No. E002/RP-04-1752, INITIAL FILING at 8-2.
[8] *2004 Resource Plan,* Docket No. E002/RP-04-1752, ORDER APPROVING RESOURCE PLAN AS MODIFIED, FINDING COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVES STATUTE, AND SETTING REPORTING REQUIREMENTS at 9 (July 28, 2006).

Q. WHAT NEXT STEPS DID THE COMPANY TAKE TO SEEK APPROVALS TO INCREASE GENERATING CAPACITY AT MONTICELLO?

A. In January 2007, the Company made a compliance filing in the 2004 Resource Plan with the Commission, providing additional details regarding the Monticello, Prairie Island, and Sherco 3 upgrades. In this filing, the Company described the value of additional baseload capacity from its nuclear units over a 20-year time horizon, including the value associated with avoided increases in emissions.[9]

In the Company's 2007 Resource Plan proceeding, the Commission reaffirmed that the long-term upgrades recommended at Monticello and Prairie Island were appropriate to meet the anticipated needs over the planning period and approved the Company's five-year action plan.[10] Xcel Energy prepared an application for certificate of need to increase capacity at Monticello and Prairie Island.

VI. EPU CERTIFICATE OF NEED

Q. PLEASE DESCRIBE THE CERTIFICATE OF NEED PROCESS FOR THE MONTICELLO EPU.

A. In its Resource Plan Order, the Commission directed us to prepare the certificate of need application promptly. While the Commission allowed us extensions in the time to file the application, the Company had to proceed on a multi-track to meet our commitment.

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[9] *2004 Resource Plan,* Docket No. E002/RP-04-1752, COMPLIANT FILING at 11 (Jan. 2, 2007).
[10] *2007 Resource Plan,* Docket No. E002/RP-07-1572, ORDER APPROVING FIVE-YEAR ACTION PLAN AS MODIFIED AND SETTING FILING REQUIREMENTS at 14 (Aug. 5, 2009).

In order to move the Program forward promptly, we undertook a high-level analysis of the projected costs of the LCM/EPU Program. We relied primarily upon the estimates provided to us from our primary contractor at the time, General Electric.

We did not undertake detailed design and engineering at that time to refine the estimates because this would have taken several years and would have been very expensive and essentially infeasible. Further, we believed that this initial estimate was adequate for modeling purposes. The benefit from continued operations at Monticello was such at the time that the lack of precision in the estimate would not have made a material difference, as the benefits were so significant.

The Company filed its application for certificate of need in Docket No. E002/CN-08-185 on February 14, 2008 ("Monticello LCM/EPU CON"). This application described a series of projects necessary to obtain 71 MW of projected capacity increase and to ensure that that the plant would be able to operate in a safe and reliable manner through 2030.

At that time, the Company estimated that the overall cost of the initiative would be approximately $320 million (including a replacement steam dryer that was added to the project). The breakdown of these costs for the purposes of the certificate of need was $133 million for the EPU and $189 million for the LCM upgrades.[11]

[11] *See* Response to Information Request OES-1194 in Docket No. E002/GR-10-971, Attachment B, May 25, 2011.

I note that at the time of the certificate of need we recognized that the value of ongoing nuclear generation was significantly cheaper than any reasonable replacement resource. As a result the high-level estimates we used for total cost were adequate for modeling purposes at the time.

Q. WHY DID THE COMPANY DIVIDE THE COSTS BETWEEN THE LCM AND EPU COMPONENTS OF THE PROGRAM?

A. As discussed in the testimony of Mr. O'Connor, Xcel Energy did not approach the overall program as two separate projects. Rather, we considered the upgrades to be necessary for the ongoing safe and reliable operation of Monticello through its extended life.

However, the Commission's certificate of need rules required that the Commission compare the proposed capacity addition against other alternative sources of capacity. In order to provide the Commission with a basis to compare the additional 71 MW against other alternatives, the Company performed a high-level allocation of costs between the EPU and LCM aspects. The split that was used in the certificate of need was not based on an "avoided cost" analysis but was rather based on a conservative allocation of the installations that are part of the Program. Based on that conservative review, 41.6 percent of the costs were allocated to EPU and 58.4 percent allocated to LCM. This rough estimate allowed the Company to undertake Strategist analysis of the hypothetical cost of the incremental megawatts.

In subsequent proceedings, stakeholders have been interested in the basis for this allocation of costs. Notably, in our recently-completed rate case (Docket E002/GR-12-961), the Administrative Law Judge ("ALJ") Report observes that the Company had not provided an adequate explanation of the division of the costs between the LCM and the EPU components. As part of the current proceeding, therefore, we conducted an analysis of the modifications that were installed. As described in the testimony of Mr. O'Connor, the Company conducted an assessment of what modifications could have been avoided had we not proceeded with the EPU, or conversely, which modifications would have to occur regardless of the EPU. This 'avoided cost' analysis had not been done at the certificate of need stage.

Q. PLEASE SUMMARIZE THE MODELING RESULTS IN THE CERTIFICATE OF NEED PROCESS THAT SUPPORTED THE COMMISSION'S DECISION TO GRANT THE CERTIFICATE OF NEED.

A. Our Strategist modeling relied on the same demand assumptions as the modeling used in the 2007 Resource Plan. It showed that proceeding with the upgrades at Monticello was the lowest-cost available alternative. A PVRR comparison over the remaining life of the Monticello extended operating license showed that adding 71 MW at Monticello was $169 million less expensive than adding a natural gas combustion turbine, $273 million less expensive than a coal Power Purchase Agreement ("PPA"), and $514 million less than a biomass alternative.[12] Sensitivity analyses confirmed this result.

Q. DID THE COMPANY REVISIT ITS ECONOMIC ANALYSIS IN THE CERTIFICATE OF NEED PROCEEDING?

A. Yes. While the Monticello LCM/EPU CON was pending, the United States experienced a significant downturn in the overall economy and entered into the Great Recession. We presented an updated analysis of the Monticello

[12] Monticello LCM/EPU CON, Application, Feb. 14, 2008, at 6-16, Table 6-6.

program based on revised information and confirmed that proceeding with the LCM/EPU Program was appropriate. At that time, natural gas prices had softened somewhat but remained relatively high and the trend did not yet suggest the dramatic price decreases that came a few years later as the impact of hydraulic fracturing and horizontal drilling became clear. Further, while the recession impacted sales, at this point it was not clear the extent of the impact on our long-term forecast.

Q. PLEASE DESCRIBE THE COMMISSION'S ORDER IN THE EPU CERTIFICATE OF NEED PROCEEDING.

A. The Company's request for a certificate of need was initially reviewed by an ALJ who found that the program described in the Application was appropriate and in the public interest.[13] The Commission agreed and granted the requested certificate of need in its Order.[14]

Q. DID THE COMPANY UPDATE ITS ANALYSES AFTER THE JANUARY 2009 ORDER?

A. Yes. Minnesota Rule 7849.0400, Subpart 2H requires a filing if there is an expected delay in the implementation of a certificate of need. We recognized that the costs and the timing of the upgrade program were changing. Because the NRC license review process was taking longer than we expected, we made two filings with the Commission advising of delays in the process.

In November 2009 we advised the Commission that the NRC decided to delay review of our license amendment request.[15] It was our understanding

[13] ALJ Report, Docket No. E002/CN-08-185, Nov. 19, 2008, Findings 85 and 87.

[14] January 8, 2009 ORDER GRANTING CERTIFICATE OF NEED AND GRANTING ENVIRONMENTAL ASSESSMENT.

[15] *See Status of Extended Power Uprate at Monticello Nuclear Generating Plant,* Docket No. E002/CN-08-185, Nov. 5, 2009.

that the Commission was not required to issue a formal decision, and thus, we merely advised the Commission of the expected delay.

Second, we filed a formal Notice of Changed Circumstances on November 22, 2011, explaining that the Program was delayed due to the impacts of Fukushima and continued delays in the NRC review of our license amendment. We advised the Commission that final implementation of the Program would be delayed until the 2013 scheduled refueling outage at the plant to ensure adequate time to implement all of the components and ongoing safe and reliable operation of the plant. On January 6, 2012, the Commission notified the Company that the proposed change in timing of the Program was acceptable without the need to reopen the certificate of need.[16]

VII. MODELING CONFIRMS MONTICELLO'S VALUE

Q. DID THE COMPANY CONDUCTED AN ANALYSIS OF THE RATEPAYER IMPACTS OF THE MONTICELLO LCM/EPU PROGRAM?

A. Yes. The Company prepared a Strategist analysis based on the final cost and timing of the Program to assess the value of continued operation of the Monticello plant for ratepayers.

Q. DID THE COMPANY HAVE AN UNDERLYING ASSUMPTION FOR THE MODELING WORK THAT WAS DONE IN SUPPORT OF THIS PROCEEDING?

A. Yes. All of the work that was done at Monticello was done for the primary goal of ensuring that it would remain a viable resource in our portfolio through 2030. We would not have undertaken the EPU activities had we not

[16] ORDER, Docket No. E002/CN-08-185, Jan. 6, 2012.

already decided to undertake the LCM activities necessary to support the renewed operating license. As a result, we consider the overall investment in Monticello – $665 million – to be in support of the long-term viability of the plant as a whole and that the value of Monticello should be judged as a whole operating unit, rather than making artificial distinctions in the cost of particular aspects of the plant.

Q. WHY IS THIS UNDERLYING ASSUMPTION IMPORTANT TO THIS PROCEEDING?

A. This proceeding is focusing on the costs incurred and benefits achieved by Xcel Energy in support of the long-term operation of the Monticello plant, and not just focused on the costs or value in the incremental 71 MW associated with the EPU. In the certificate of need proceeding, on the other hand, the Commission's primary focus was on whether the incremental 71 MW associated with the EPU was needed. As part of that analysis, the Company isolated the 71 MW to facilitate the Commission's determination of the value of those megawatts compared to reasonable alternatives. To support the Commission's certificate of need review of the incremental megawatts, the Company provided a good-faith breakdown of the estimated costs. That estimate was not definitive and was not based on any specific analysis but was rather a good faith conservative estimate to give the Commission a basis for considering alternatives. As I mentioned above, continued operations at Monticello were of significant value at the time compared to alternatives and would not have been outweighed by any of the alternatives even if we had understood that the estimate was too low.

The Company made all of its upgrades to Monticello with the intention of supporting long-term operations. As a result, we believe our prudence in that endeavor should be judged based upon the value of the whole plant and not just the incremental megawatts. For that analysis, we believe the proper point of comparison is to consider the cost and value of Monticello today against the cost and value associated with retirement in 2010. This 2010 retirement scenario reflects the facts that, had we not undertaken all of the life-cycle management activities described in this proceeding, we could not support long-term operations. Had that been the case, we would not have obtained the license extension.

A. Description of Strategist

Q. WHAT IS STRATEGIST?

A. Strategist is a resource planning model that determines the optimal portfolio of resources to serve forecasted load growth. The model includes four modules:

1. The Load module contains the Company's load forecast and modifies it for forecasted DSM impacts.
2. The Generation module stores the generation characteristics for all of the Company's thermal, hydro, and wind units, in addition to the energy profiles for all PPAs. The generation module simulates security constrained dispatch to meet energy demand, and keeps track of generation, fuel burn, operating costs, and emissions for each unit.
3. The Capital Expenditure and Recovery module is where all capital projects are modeled. Capital costs and escalation rates are used as inputs and the model calculates the revenue requirements for each project taking into account book depreciation, tax deprecation, insurance, property taxes, the cost of debt, and the Company's targeted return on equity.

4. The Proview module is the engine of Strategist's resource planning capability. Proview tests thousands of different resource combinations to identify the mix of new resources that will result in the lowest cost to ratepayers.

Q. HOW DOES THE STRATEGIST MODEL WORK?

A. Strategist simulates the operation of our system over a 40-year planning period, taking into account our demand and energy forecast, required reserve margin, new resources we are committed to adding, and planned retirements. The model proceeds one year at a time, simulating the hourly system dispatch, and tracking generation, system costs, and emissions. When Strategist reaches a year in which peak demand plus required reserve margin exceeds available resources, the Proview module will add various combinations of generic resources to meet the required reserves and track total system costs for each combination. At the end of the model run, Strategist identifies the least cost expansion plan as well as any sub-optimal plans evaluated during the simulation. Total system costs for each plan are summarized as the PVRR.

For the analysis in this Strategist was first run with Monticello included as an existing resource. Next Monticello was removed from the model and simulation re-run using the various scenarios I will describe in my testimony.

Q. IS STRATEGIST A WIDELY-USED MODELING TOOL IN THE UTILITY INDUSTRY?

A. Yes. According to Ventyx (a subsidiary of ABB and developer of Strategist), they have 42 clients running the Strategist model including utilities, consultants, and state public utility commissions.

Q. IN YOUR OPINION, WHY ARE STRATEGIST RESULTS RELIABLE FOR THE PURPOSES OF ANALYZING THE COSTS AND BENEFITS OF MONTICELLO AS PART OF THE COMPANY'S RESOURCE MIX?

A. Strategist has been used for several years by utilities, consultants, and state public utility commissions to evaluate a variety of long-term resource planning issues. The software's longevity and market penetration are the result of the confidence end users have in its capabilities. The software includes significant detail on system load and generation characteristics as well as detailed modeling capability for capital projects. Model results can be analyzed down to unit-level performance for each month over the 40-year time horizon. This level of granularity allows the user to build a model that closely mimics the actual system and allows for robust quality checks on the model output.

B. Modeling Effort for This Proceeding

Q. PLEASE DESCRIBE YOUR MODELING EFFORT AS IT PERTAINS TO THIS PROCEEDING.

A. The Company prepared four separate analyses pertaining to the costs incurred in implementing the Monticello LCM/EPU Program. Each of these analyses provide the Commission with a different perspective on the costs incurred as part of this initiative. The four analyses are:

1. *Hindsight Analysis*. We conducted an analysis of whether the 2008 model used in the EPU certificate of need proceeding (Docket No. E-002/CN-08-185) shows that Monticello was cost-effective at that time, even assuming we had known at that time what the total cost of the Program would be. To do this analysis, we took the 2008 model used in the certificate of need

proceeding and changed only the cost of the LCM/EPU upgrades to $665 million to determine whether the Program remained cost effective.

2. *Foresight Analysis*. We conducted an analysis of whether Monticello remains cost-effective today based on the $665 million cost and comparing that to replacement of Monticello with natural gas generation. For this analysis we assumed that, had we not embarked upon the LCM/EPU Program, we would have shut Monticello down in 2010 at the end of its original license since, without the LCM upgrades, it would not have been feasible to operate the plant through 2030.

3. *Implementation Analysis*. We conducted an annual review of whether, in light of the costs already expended on the Program and the amount of costs remaining to be spent, it was reasonable for the Company to proceed with the Program to completion. This analysis provides an opportunity to consider the value of the Program in light of the Company's actual expenditures in each year. We conducted this analysis three ways. First, we reviewed the value of Monticello in light of the costs "to go" to complete the work at the $665 million level. Second, we did an assessment of the annual value of the Program at $665 million based simply on considering whether the Program remained cost effective without regard to the costs already incurred. Third, under this analysis, we provide the output of internal modeling work that we conducted in 2010 and 2011 to provide management with an assessment of the costs and value of the Program at that time. All of these analyses are designed to assess whether it would be appropriate to reconsider decisions or change course based on changing circumstances.

4. *LCM/EPU Split Value*. Finally, we replicate the analysis that was done in the certificate of need proceeding to assess the cost and value of the incremental EPU megawatts (71 MW) using assumed values for the cost of those megawatts. We ran this analysis a number of ways for comparison. First, in preparation for this proceeding, we isolated the avoidable EPU costs that would not have been incurred had we not proceeded with the EPU. This "avoidable EPU" cost is substantially similar to how we analyzed the LCM/EPU costs in the proceeding where we sought authority to cancel the EPU certificate of need for our Prairie Island plant (Docket No. E/002-CN-09- 509 and 510). Mr. O'Connor supports this analysis and shows that 78.0 percent of the costs incurred in this Program were unavoidable LCM costs and 22.0 percent of the costs can be seen as avoidable EPU costs. For comparison, we also provide the modeling results using the assumptions used in the certificate of need proceeding – 58.4 percent LCM and 41.6 EPU. Finally, we conducted an implementation analysis of the incremental 71 MW similar to what we provided for the plant as a whole. Once we had the LCM/EPU parameters set, we ran the hindsight, foresight and implementation analyses focusing on the value of the incremental 71 MW.

I will describe each of the four analyses in the following sections.

1. Hindsight Analysis – 2008 Value at $665 Million Cost

Q. WHAT WAS THE RESULT OF YOUR HINDSIGHT ANALYSIS?

A. Had we known in 2008 that the initiative would cost $665 million, Monticello remained a valuable resource for our customers. Taking into account all of these costs, Monticello as a whole provides $1,311 million customer savings on a PVSC basis compared to a natural gas alternative based on 2008 conditions.

Q. WHY DID YOU CONDUCT AN ANALYSIS OF THE VALUE OF THE OVERALL PROGRAM AT $665 MILLION?

A. At the time that we made the decision to proceed with the LCM/EPU Program, we reasonably believed that continued generation at Monticello was cost effective based upon the information we had at that time. We had no reason to know the cost would be $665 million; however, it is an appropriate data point to consider the value of Monticello at the time we decided to move forward with the Program but at the costs that were actually incurred.

Q. WHAT IS THE COST THAT IS APPROPRIATE TO USE FOR PURPOSES OF COMPARISON WITH THE $665 MILLION?

A. Prior to the 2008 certificate of need proceeding, the Company had authorized $274 million for this initiative. In addition, during the certificate of need proceeding we determined that it would be necessary to add a new steam dryer to the list of projects, bringing the total up to about $302 million. These numbers were in 2006 dollars. Escalated, the overall cost level that is appropriate for comparison is about $320 million. This is an appropriate cost that can be used for comparison purposes.

Q. PLEASE DESCRIBE THE MODELING WORK YOU DID TO ASSESS THE VALUE OF THE MONTICELLO LCM/EPU PROGRAM IN 2008, ASSUMING $665 MILLION COST HAD BEEN KNOWN AT THAT TIME.

A. We started with the Company's September 2008 Resource Plan Reply Comments Model. This is the same model that was utilized when the

Commission granted the certificate of need in Docket 08-185. To conduct an evaluation of the LCM/EPU in that model we added the following data:

- Adjust the costs of the Monticello LCM/EPU Program to reflect the $665 million incurred through August 31, 2013.
- Added a forecast of additional capital investments necessary at the plant from 2013-2030.
- For comparison purposes we developed a retirement and replacement scenario that simulated the shutdown of Monticello in 2010. For this scenario we added the cost of a new natural gas combined cycle plant to replace Monticello and the costs for decommissioning of the plant in 2011.

Q. WHAT WERE THE RESULTS OF THE ANALYSIS ?

A. The results show that had the Company known the total cost of the LCM/EPU Program would be $655 million we still would have recommended the continued operation of the plant. The total present value of societal costs ("PVSC") for the system with continued operation of Monticello was estimated to be $4.4 billion. In comparison the total cost for replacing Monticello with a natural gas combined cycle was $5.7 billion. The largest difference between the two scenarios was the cost to replace the energy generated by Monticello. In 2008, the price of natural gas reached its all time peak and the forecasts used by the Company at the time reflected the current status of the market. The natural gas forecast in the 2008 Strategist model started with an initial price of over $9/mmBtu in 2010; it then decreased to under $8/mmBtu in 2015 before starting a long term growth rate of 3 percent. In comparison to the $4/mmBtu gas prices that we see today, our assessment of natural gas in 2008 was very bleak. The output of this analysis is shown in Table 5.

Table 5. 2008 Hindsight (Total Plant) Value at $665 MM

Monticello Life Extension + EPU	PVSC Results $millions	Monticello Retirement and Replacement	PVSC Results $millions
Monti Decomissiong (2031)	$148	Monti Decomissioning (2011)	$423
EPU/LCM+On-Going Capital	$1,266	Replacement Capacty	$1,615
Monti O&M	$1,959	Replacement Energy	$2,954
Monti Fuel	$893	Incremental Emissions	$585
Monti Total	$4,266	Total Retirement Costs	$5,577
		Net PVSC (Benefit)/Costs	**($1,311)**

As can be seen from Table 5, when modeled under 2008 conditions, the $665 million overall cost of the initiative still provides savings to our customers compared to a replacement capacity resource on a total plant basis.

2. *Foresight Analysis – 2013 Value at $665 Million Cost*

Q. WHAT WAS THE RESULT OF YOUR FORESIGHT ANALYSIS?

A. In 2013, had we known that the initiative would cost $665 million, Monticello remains a valuable resource for our customers. Taking into account all of these costs, Monticello as a whole provides $174 million customer savings on a PVSC basis compared to a natural gas alternative based on 2008 conditions. We also ran low/high natural gas and no/high carbon sensitivities as well as a 10-year extension scenario. These show that the value of the plant is sensitive to the volatility of gas and carbon costs. Even a modest increase in natural gas or carbon costs would magnify the value of retaining Monticello's carbon free generation for as long as reasonably possible.

Q. PLEASE DESCRIBE THE FORESIGHT ANALYSIS.

A. In this scenario we review the value of Monticello in 2013 at the $665 million cost level. This provides an after-the-fact snapshot of cost/benefit of Monticello under current conditions. This analysis assumes that we had foresight to know both Monticello's final cost and 2013 market conditions, particularly pertaining to the price of natural gas.

Of course, we did not have such foresight and the generation markets changed dramatically from 2008 to 2013. The Great Recession of 2009 had a dramatic impact on our demand forecast, and the advent of hydraulic fracturing and horizontal drilling has had a dramatic impact on the cost of natural gas. Neither of these changes was foreseeable when the certificate of need was granted.

Nevertheless, we believe this analysis provides a useful data point for the Commission's consideration. This analysis shows that $665 million in support of the long-term viability of Monticello is more cost-effective in 2013 compared to an early shut-down of the plant. The PVSC difference of these two scenarios shows Monticello provides $180 million in savings through 2030.

Q. PLEASE DESCRIBE THE STRATEGIST BASE CASE THAT YOU UTILIZED FOR THIS REVIEW.

A. We used the same modeling assumptions that were used in the model for the pending competitive acquisition docket.[17] That Strategist model included the following important input assumptions:

- *Load Forecast*. The load forecast used in this model was developed in the spring of 2013 and reflects our most current assessment of the impacts of conservation (Demand Side Management ("DSM")) on total customer demand. The forecasted peak demand during the resource acquisition period is; 2017 – 9,500 MW, 2018 – 9,590 MW, and 2019 – 9,676 MW.

- *Load Management Forecast*. The forecast of load management or direct load control programs was developed in spring of 2013. Total load management is 985 MW in 2013 and grows at an average rate of one percent annually through 2020 reaching 1056 MW in that year.

- *Reserve Margin*. To set reliability standards the model uses a reserve margin of 3.79 percent as established in MISO's November 2011 loss of load expectation ("LOLE") report.

- *Natural Gas & MISO Market Prices*. The model includes natural gas and market pricing from late July 2013. The updated natural gas forecasts starts at $3.72/mmBtu and escalates at 4.6 percent through 2030. The levelized price of gas during the 18-year period from 2013 through 2030 is

[17] *In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process,* Docket No. E002/CN-12-1240.

$5.35/mmBtu. The 2013 price of market energy is $23.12/MWh for off peak and $35.89/MWh for on peak. Market energy escalates at 4.1 percent and the levelized prices are $31.74/MWh for off peak and $49.72/MWh for on peak.

- *Emission Pricing.* The base model includes the midpoint values for the Commission established externality values, including $21.50/ton for CO2 starting in 2017.

- *Accredited Capacity.* The summer firm capacity values used in the model reflect the unforced capacity values ("UCAP") used in this summer's MISO Module-E resource adequacy standard.

- *Retirements.* The model includes the retirement of Black Dog 3 and 4 in the spring of 2015 for compliance with Environmental Protection Agency's Mercury and Air Toxins rule ("MATS"). The model also assumes the retirement of Key City and Granite City at the end of 2016.

- *Resource Additions.* We have budgeted capital for repair and return to service of our French Island 3 peaking unit in spring of 2016, and its return is reflected in the Strategist model.

- *Wind.* The model includes the 750 MW of wind recently proposed by the Company. In addition the model contains a long-term wind expansion plan designed to achieve and then maintain our 30 percent renewable energy standard. The long term wind expansion plan starts in 2022 with a 100 MW addition and grows to 1,500 MW of additional wind by 2030.

- *Solar*. We have included a preliminary estimate of the solar expansion plan necessary to comply with the recent Minnesota Solar Energy Mandate. Our solar expansion plan reaches about 280 MW by 2020. Pending updated results from our effective load carrying capability ("ELCC") study we are assuming an accreditation factor of 42 percent.

Q. WHAT ARE SOME OF THE MONTICELLO-SPECIFIC INPUT ASSUMPTIONS YOU USED IN YOUR STRATEGIST ANALYSIS?

A. For this analysis we refined our assumptions regarding the costs and operating characteristics at Monticello. The relevant updates include:

- *Capacity*. The maximum capacity of the unit is rated net at 585 MW in 2015. The EPU is assumed to come into service January 1, 2014 and add 71 MW, increasing the maximum net capacity to 656 MW.

- *Maintenance Schedule*. The model was updated to reflect the extended plant outages in 2011 and 2013. For the remaining operating life the plant we assume 5 week refueling outages every other year occurring in spring.

- *LCM & EPU Capital*. Strategist includes a total of $665 million for LCM/EPU Program capital. The model's base year is 2011, and by the beginning of this year $292 million had been spent and was input into Strategist as the beginning capital balance. From 2011 through 2013 another $373 million was spend and is reflected as annual capital expenditures in the model. The total capital for the LCM/EPU Program is assumed to be added to rate base in May 2013 with revenue requirements starting in that month. The LCM/EPU investment is depreciated over the remaining life of the plant.

- *On-Going Capital.* The capital forecast used in the Strategist model was developed in August of this year. From 2014 through 2030 the average annual capital investment is $24 million per year for a total of $433 million in total additional investments over the remaining life of the plant.

- *Operating and Maintenance Expenses.* The plant O&M budget forecast was also updated in August of this year. The O&M forecast used in Strategist averages $145 million per year from 2013 through 2030.

- *Decommissioning Costs.* The plant's decommissioning costs were based on the Company's Triennial Decommissioning Accrual Update. The total decommissioning costs included in the model are $978 million in terms of 2011 dollars. After applying escalation factors, the total decommissioning expenses total $2.6 billion for the 2030 retirement scenario. To ensure that the decommissioning fund is adequate to support these expenditures, the Monticello plant is assumed to accrue $14.3 million from 2013 through 2030.

- *Employee Retention Expense.* Our initial evaluation of the license renewal at Monticello included in employee retention cost of $45-$90 million. Recently Dominion stated in their October 25, 2012 Third Quarter Form 10Q report that the decommissioned Kewaunee plant experienced approximately $50 million in employee retention costs. For the Strategist analysis we included $50 million in employee retention costs that are spread equally over the last two years of operation. The $50 million cost is assumed to be in 2013 dollars and for the 2030 retirement scenario the $50 million was escalated at 2.51 percent, which is our base assumption for labor cost inflation. I note that Dominion also reported a write down of materials and supplies inventories of $33 million and a $24 million charge related to severance costs. Xcel Energy anticipates it would have similar types of costs in an early-shutdown scenario. However, since we have not previously analyzed these two categories of costs, we have not included them in the Strategist analysis but recognize costs of this type would likely occur.

Q. WHAT WAS THE RESULT OF THIS ANALYSIS?

A. The Strategist results demonstrate that even with today's low gas prices the $665 million investment for Monticello's LCM and EPU Program is still cost effective and creates a net PVSC savings of $174 million. The forecasted cost of replacement energy fell by over $1 billion as a result of lower natural gas prices. This was partially offset by lower forecasted O&M at Monticello. The 2008 model used an average annual fixed O&M of $165 million per year. This forecast was developed as part of the 2007 resource plan, and because life extension of Monticello was not an issue studied in that proceeding the O&M forecast was not particularly refined or thoroughly reviewed. For our 2013 analysis a new forecast of fixed O&M was developed by senior management who oversee our nuclear facility. This refined forecast averages $145 million per year. Table 6 provides the details of our updated Monticello life extension analysis.

Table 6. 2013 Foresight (Total Plant) Value at $665 MM

Monticello Life Extension+ EPU	PVSC Results $millions
Monti Decomissiong (2031)	$148
EPU/LCM+On-Going Capital	$1,397
Monti O&M	$1,720
Monti Fuel	$688
Monti Total	$3,952

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decomissioning (2011)	$419
Replacement Capacity	$1,349
Replacement Energy	$1,945
Incremental Emissions	$412
Total Retirement Costs	$4,126
Net PVSC (Benefit)/Cost	**($174)**

As can be seen from Table 6, when modeled under 2013 conditions, the $665 million overall cost of the initiative still provides savings to our customers compared to a replacement capacity resource on a total plant basis.

Q. DID YOU RUN ANY SENSITIVITIES AROUND THIS 2013 ANALYSIS?

A. Yes. We ran five sensitivities to assess the value of Monticello under various circumstances to determine how changes in our assumptions impact the costs or characteristics of Monticello on a total plant basis. These scenarios were:

- *CO_2 Planning Value Sensitivity*. The Commission set the value range for CO_2 to a range of $9 to $34 per ton. For our base case, we used the mid-point of that range. For purposes of showing the sensitivity around this midpoint, we analyzed two scenarios – $0/ton) and $34/ton.

- *Natural Gas Price Sensitivity*. To test the impact of the natural gas price assumption, we varied the growth rate of our price forecast by 50 percent. Under the base assumption, gas prices grew at an average rate of 3.1 percent. Under the low gas price sensitivity, the price grows at 1.5 percent, and under the high gas price sensitivity the growth rate is 4.6 percent.

- *10-Year Extension.* This scenario assumes that Monticello is granted authority to operate for an additional 10 years from 2030 to 2040. We used the same forecast as with the 2013 scenarios described above with the following additional refinements: for capital expenditures, we used an escalated average and then included a three-year capital reduction in the final three years to simulate end of life. For O&M, we simply extended the 2013 model assumptions at the average growth rate.

Table 7 provides the results of this sensitivity analysis.

Table 7. 2013 Sensitivities

Sensitivities	**PVSC Results (Benefit)/Costs $millions**
CO2 - $0/ton	$303
CO2 - $34/ton	($436)
Low Gas	$119
High Gas	($511)
10yr Ext	($433)

As can be seen from Table 7, these sensitivities create a significant swing in the value of Monticello when modeled under 2013 conditions.

- *CO_2 Sensitivities.* In our base case analysis, we included the mid-point of the carbon values ordered by the Commission to be included in our modeling. Due to the uncertainty of future CO_2 regulation, it is appropriate to consider the costs of resources with high and low assumptions for carbon costs. These sensitivities show that the current value of Monticello compared to natural gas resources on a total plant basis varies significantly depending upon the assumption used. This variability and uncertainty around the impact of carbon costs highlights the value of nuclear as a carbon-free resource as, regardless of the cost ascribed to CO_2, nuclear generation does not contribute to the increase in carbon emissions.

- *Natural Gas Sensitivities.* This evaluation is very sensitive to changing natural gas prices. Natural gas prices are currently at historically low levels, and it seems unlikely that they will fall much further. To the contrary, it is more likely that natural gas prices will stay at about their current levels or rise during the remainder of Monticello's life. Even a small increase in natural gas prices increases the value of continued nuclear generation. This illustrates the value of having nuclear generation as a fuel hedge.

- *10-Year Extension.* If Xcel Energy is able to continue operating Monticello beyond 2030 without extraordinary expenditures, customers will realize significant savings based on conditions predicted in 2013. While it is not possible to say at this time whether a further extension may be available or reasonable at the time, this scenario suggests that continuing to include nuclear generation in our resource mix remains an attractive supply option and preserves what may be an even more valuable component of our fleet in years to come.

3. Implementation Analysis

Q. WHAT WAS THE RESULT OF YOUR IMPLEMENTATION ANALYSIS?

A. This analysis provides a look at our actual annual investment in the Program and assess whether it remained cost effective to continue forward with implementation. We reviewed this taking into account our sunk costs and also without factoring those sunk costs into the mix. On both bases, the analyses show that it was reasonable for the Company to continue forward with the Program.

Q. WHAT IS THE IMPLEMENTATION ANALYSIS?

A. Installation of the modifications in furtherance of the LCM/EPU Program took approximately five years from 2009 through 2013. This implementation analysis provides information on whether the investment over time remained cost effective in light of the changes in the energy markets that have occurred in the past five years. We provided this analysis using three different sets of assumptions: (i) annual look at the value of Monticello at $665 million taking into account the amounts actually incurred at the time; (ii) annual look at the value of Monticello at $665 million without taking into account amounts actually incurred; and (iii) review of internal analyses conducted in 2010 and 2011 to consider the ongoing value of the initiative.

a. Incremental Cost Analysis

Q. PLEASE DESCRIBE THE INCREMENTAL COST ANALYSIS.

A. The Company began spending money in 2007 and 2008 for design and other preparatory work. From 2009 through 2013 we paid for the installation and other final work. This analysis recognizes this expenditure of funds as sunk costs and considers whether it was cost-effective to proceed with the initiative in light of the money we had already spent. In other words, at any given point, was it cost-effective to proceed in light of how much of the $665 million we had left before we finished the initiative.

Q. WHY DID YOU CONDUCT A COST ASSESSMENT OF THE IMPACT OF THE COSTS INCURRED DURING IMPLEMENTATION?

A. This assessment is intended to factor into the analysis that each year during the Program implementation some of the costs had already been spent or committed and therefore would be sunk costs if the decision was made to stop the project and retire the plant. To provide this information, we conducted six different simulations from 2008 to 2013. Each simulation used a Strategist base case from the year being studied. The analysis compares the cost of the LCM/EPU Program and its forecasted benefits to the costs of retiring the plant plus the sunk cost that was incurred by that date. Table 8 provides a depiction of how much capital was assumed to be sunk in each year and how much capital was left to be spent (to-go).

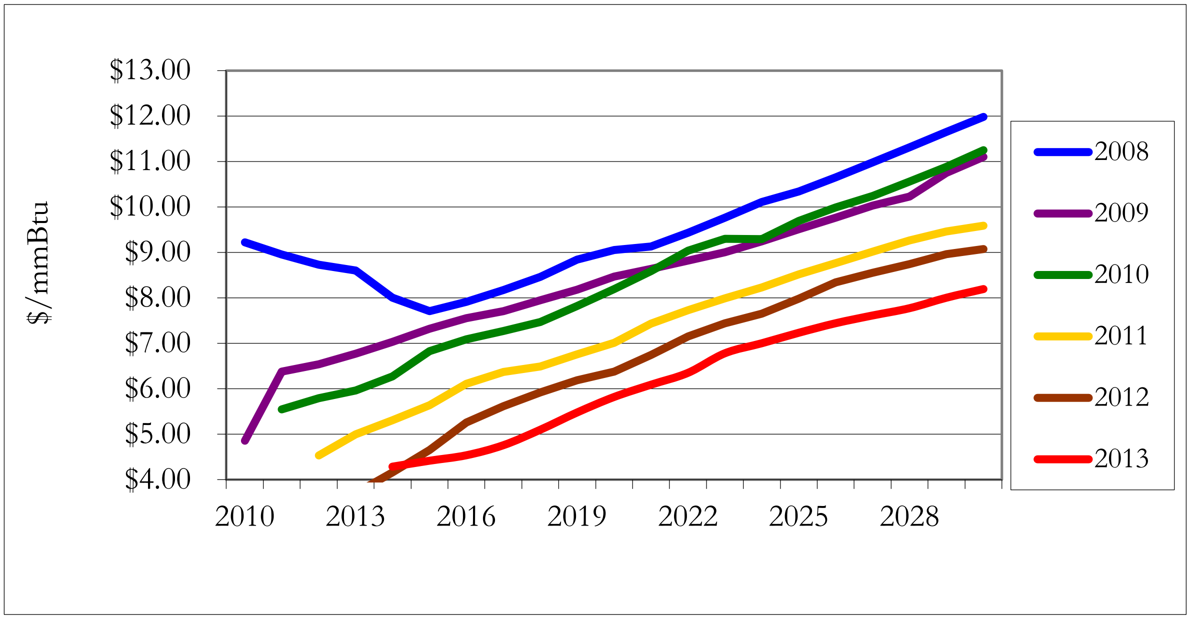
Table 8. Assumed Capital on an Annual Basis

Simulation Year	**EPU/LCM Spent to Date** (sunk cost)	**Remaining EPU/LCM Capital** (to-go)	**Total Capital**
2008	$97M	$568M	$665M
2009	$216M	$449M	$665M
2010	$292M	$373M	$665M
2011	$466M	$199M	$665M
2012	$513M	$152M	$665M
2013	$665M	$0M	$665M

Q. HOW WERE THE ANNUAL SIMULATIONS CONDUCTED?

A. We began by collecting representative Strategist base cases from each year 2008 through 2013. These models include assumptions regarding load growth, fuel price, and emissions costs that were current as of that year. One model assumption that has particular impact on the EPU/LCM analysis is the cost of the natural gas that would be used as a source of replacement energy if the plant had been retired. From 2008 to 2013 forecasts of natural gas prices have fallen steadily. Figure 5 illustrates that since 2008 the forecasted price of natural gas has fallen over $3/mmBtu.

Figure 5. Natural Gas Price Forecast



For each simulation we added the total capital cost of $665 million for LCM/EPU Program and had Strategist calculate the corresponding revenue requirements based on the financial assumptions that were used in the models at the time. We also added the cost of decommissioning of the plant in 2031.

For the retirement and replacement scenario, we added the sunk costs associated with the LCM/EPU Program but then specified that Monticello retires with associated decommissioning costs, and is replaced with a natural gas combined cycle plant. The Strategist simulation then calculated the revenue requirements for the replacement combined cycle and the total cost of replacement energy. The Strategist models used in the implementation analysis were:

- 2008: September 2008 Resource Plan Reply Comment model;
- 2009: September 2009 Black Dog Analysis model;
- 2010: July 2010 Resource Plan model;
- 2011: September 2011 Resource Plan Update model;
- 2012: September 2012 Prairie Island EPU re-evaluation proceeding model; and
- 2013: September 2013 Competitive Resource Acquisition model

Q. WHAT WERE THE RESULTS OF YOUR IMPLEMENTATION ANALYSIS?

A. Table 9 summarizes the implementation analysis. As can be seen from the table, the work at Monticello remains cost effective in each of the years that we analyzed. The implication being that in each year, when taking into consideration the capital that had already been spent on the project and the remaining capital to-go, the decision to continue to move forward on the project would have been prudent and in our customers' best interest.

Table 9. Monticello Implementation Analysis

Simulation Year	Monticello Life Extension + EPU PVSC $millions	Retirement & Replacement + LCM/EPU Sunk Costs PVSC $millions	(Benefit) from LCM/EPU PVSC $millions
2008	$4,266	$5,749	($1,483)
2009	$4,338	$5,629	($1,292)
2010	$3,986	$5,653	($1,667)
2011	$3,599	$5,623	($2,024)
2012	$3,593	$5,186	($1,593)
2013	$3,952	$5,170	($1,218)

As can be seen from Table 9, each year along the way, our continued implementation of the Program was reasonable based on the amount spent to date and the amount remaining toward the $665 million overall cost of the initiative.

b. Annual Review

Q. PLEASE DESCRIBE THIS ANNUAL REVIEW ANALYSIS YOU DID.

A. For purposes of this analysis, I simply took the incremental cost analysis from above and took out the "to-go" costs incurred. In other words, I reviewed the value of Monticello against annual current conditions without regard to the amount actually spent to-date.

Q. WHY DID YOU DO THIS ANALYSIS?

A. Essentially this is implementation analysis without taking the benefit of accounting for the removal of sunk costs. This analysis assumes perfect foresight as to the changes in the market and cost of the Program. Obviously we could not have had perfect foresight. Nevertheless, this analysis allows us to view whether, at certain milestones along the way, it might have made sense not to reevaluate the project based on current circumstances. With perfect foresight, we might have been able to predict the changes that occurred in 2009-11 (with regard to shrinking sales forecasts and reduced natural gas prices) and assessed whether our work at Monticello, at $665 million, remained in our customers' interest.

Q. WHAT WAS THE OUTCOME OF THIS ANALYSIS?

A. Table 10 provides the outcome of this annual review.

Table 10. LCM+EPU – Annual Review Analysis

Simulation Year	Monticello Life Extension + EPU PVSC $millions	Retirement & Replacement PVSC $millions	(Benefit) from LCM/EPU PVSC $millions
2008	$4,266	$5,577	($1,311)
2009	$4,338	$5,230	($892)
2010	$3,986	$5,126	($1,141)
2011	$3,599	$4,839	($1,240)
2012	$3,593	$4,339	($745)
2013	$3,952	$4,126	($174)

Q. HOW DID YOU CONDUCT THIS ANALYSIS?

A. I used the same annual models that I used for the incremental cost analysis above. I simply removed the sunk cost from each year.

Q. PLEASE EXPLAIN THESE RESULTS.

A. The variability in this Table is a function of the inputs into the legacy models and the impact of falling natural gas prices. In 2009 the value of Monticello fell when judged against the 2009 vintage model. However, in 2010 and 2011, we revised our capital and O&M assumptions for Monticello downward. This had the impact of increasing the benefit of retaining the Program. By contrast, in 2012 when natural gas prices fell dramatically, the value of Monticello fell correspondingly.

Q. I NOTE THAT THE 2013 LINE FROM TABLE 9 AND TABLE 10 DO NOT MATCH AND THAT THE COST OF RETIREMENT AND REPLACEMENT IS APPROXIMATELY $1 BILLION DIFFERENT ON A PVSC BASIS. CAN YOU EXPLAIN THE DIFFERENCE?

A. Yes. The base model for 2013 is the same in both instances; hence the column for Monticello costs is the same in both Tables. The same analysis was conducted to determine the replacement. Table 9 is a forward looking incremental cost perspective. In 2013 the capital costs of the project was already sunk or not avoidable and not included in the analysis. Table 9 demonstrates that in 2013 there is substantial benefit at minimal cost to complete the program. In Table 10 we take a total cost perspective. Table 10 includes the capital cost of the project in the analysis to examine, retrospectively, whether the program provides value. The difference is primarily the revenue requirements associated with the $665 million investment.

c. Internal Analyses

Q. DID YOU CONDUCT ANY ANALYSIS IN THE 2010 AND 2011 TIMEFRAME TO ASSESS THE CONTINUED VALUE IN PROCEEDING WITH THE LCM/EPU PROGRAM?

A. Yes. We conducted two such analyses for internal management review. One was in May 2010 and was designed to provide sensitivities around the relative value of the EPU/LCM Program compared to a scenario where the uprate was not installed. In this analysis we determined the Program was still cost effective and with an additional $50 million in cost attributed to the EPU megawatts it was approximately breakeven. At that time we did not know the magnitude of the final costs and reasonably concluded that these scenarios justified going forward. This was particularly true as in May 2010 when we conducted this analysis, we had already spent well over $200 million. We did not, at that time, do a sunk cost analysis.

The second analysis was conducted in May 2011, after the 2011 implementation outage.[18] This internal analysis utilized the original model used to evaluate the EPU Program in 2008. At the time we had identified an additional $79 million in capital above our original estimate. The analysis indicated that even if the entire $79 million was attributed to the EPU Program, it would have still been prudent to pursue the Program.

[18] Since 2010, our long-term forecast demand has remained soft largely as a result of the aftermath of the Great Recession. In addition, in about 2011, natural gas prices have fallen sharply and now are at historically-unprecedented low prices due to the commercialization of hydraulic fracturing and horizontal drilling. By the time these two fundamental changes in the energy market had become clear, we had already spent over half of the capital in furtherance of the Program.

4. *Incremental Value of EPU Megawatts*

Q. WHAT WAS THE RESULT OF YOUR INCREMENTAL ANALYSIS?

A. The value of the incremental 71 MW of capacity associated with the EPU varies depending upon the assumptions used. Using the avoided cost analysis that we have conducted as part of this case, the value of the incremental 71 MW is roughly equivalent to the value of natural gas generation.

Q. WHY DID YOU CONDUCT AN ANALYSIS OF THE VALUE OF THE INCREMENTAL EPU MEGAWATTS?

A. In implementing the overall Program, the Company did not distinguish between the LCM and EPU components as we viewed the Program as a single unified effort. From a project perspective, we did not split the costs between LCM and EPU functions. Nevertheless, we recognize that the Commission and stakeholders may be interested in assessing the value of the incremental megawatts under assumed conditions because of the analysis that was done in the certificate of need proceeding. We, therefore, provide a similar analysis here.

Q. HOW DID THE COMPANY CHOOSE THE LEVELS OF LCM AND EPU COSTS FOR PURPOSES OF THIS ANALYSIS?

A. Mr. O'Connor provides a discussion of how the Company made its selections of levels for this analysis.

First, Mr. O'Connor's testimony provides an analysis of the "avoidable EPU" costs and those LCM costs that would have been unavoidable even if we had not undertaken the EPU. Using that avoidable EPU cost analysis, the Company allocates 22.0 percent of the costs to the avoidable EPU activities, and 78.0 percent to LMC costs that would have been incurred anyway. Table 6 provides the total capital amounts associated with these LCM/EPU splits.

Second, during the EPU certificate of need proceeding, our high level estimates implied an allocation of 41.6 percent of the costs to the EPU and 58.4 percent to the LCM activities. While this split was not intended to portray an avoided cost analysis, it is the split that was used in the certificate of need proceeding and was a subject of our 2013 test year rate case (Table 11).

Table 11. LCM/EPU Split

LCM/EPU Split	LCM Capital $million	EPU Capital $million	Total Capital $million
Avoidable EPU Scenario	$518.9 (78.0%)	$146 (22.0%)	$665 (100%)
Certificate of Need Scenario	$388 (58.4%)	$277 (41.6%)	$665 (100%)

Q. WHY DID YOU NOT FOCUS ON THE INCREMENTAL COST OF THE EPU IN YOUR ANALYSIS?

A. The Company believes that the real value of Monticello is in its continued safe and reliable operation through 2030 and potentially beyond so that we can capture the fuel diversity, environmental benefits and relatively low-cost generation. While the EPU was an important initiative, it must be seen in the context of the overall strategy of maintaining long-term viable generation at the site.

Q. HOW WAS STRATEGIST USED TO EVALUATE THE MONTICELLO EPU?

A. For this analysis we used the same 2013 model and assumptions that I previously described. We began with a base case that included either 58.4 percent or 78.0 percent of the total $665 million LCM/EPU cost. In this base case Monticello is not uprated and the net generating capacity remains at 585 MW through 2030. This base case is compared to the scenario where the full $665 million is spent and the plant's capacity increases by 71 MW to 656 MW starting January 1, 2014.

Comparison of these scenarios provides a cost/benefit estimates of the EPU at a total cost of $146 million (22.0 percent) and at $277 million (41.6 percent).

a. Value of 71 MW

Q. WHAT WERE THE RESULTS OF THE EPU ANALYSIS IN STRATEGIST FOR THE 78.0 PERCENT LCM/22.0 PERCENT EPU CASE?

A. The Strategist simulations showed that at a total capital cost of $146 million (22.0 percent) the EPU project resulted in a net increase in PVSC. Costs of the EPU consist only of revenue requirements that result from the capital invested and higher fuel costs associated with the larger capacity and generation output. If the EPU had not been implemented the incremental capacity would have likely been replaced with additional peaking capacity and the energy from the EPU would have been replaced with a mixture of higher generation from existing plants and additional purchases from the MISO market.

Q. USING THE 2008 MODEL, WHAT IS THE HINDSIGHT COST AND VALUE OF THE INCREMENTAL 71 MW?

A. Assuming the total EPU costs were $141 million (22.0 percent), the project shows a net PVSC savings of $151 million. The impact of the EPU is small in the context of the overall Monticello plant. Table 12 summarizes the Strategist results for the 22.0 percent EPU scenario.

Table 12. 2008 Model Hindsight – 22 Percent EPU

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decomissiong (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello LCM Only 58%	PVSC Results $millions
Monti Decomissiong (2031)	$148
EPU/LCM+On-Going Capital	$1,057
Monti O&M	$1,954
Monti Fuel	$812
Replacement Energy	$295
Replacement Capacity	$81
Incremental Emissions	$69
Total Retirement Costs	$4,417
Net PVSC (Benefits)/Costs	**($151)**

Using the 42 percent attributed to the EPU similar to the certificate of need allocation, the total cost of the EPU is increased to $277 million. Obviously, with higher capital cost the project looks less attractive. Table 13 shows that the net PVSC impact under the higher cost assumption is $36 million.

Table 13. 2008 Model Hindsight – 42 Percent EPU

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommissioning (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello LCM Only 58%	PVSC Results $millions
Monti Decommissioning (2031)	$148
EPU/LCM+On-Going Capital	$870
Monti O&M	$1,954
Monti Fuel	$812
Replacement Energy	$295
Replacement Capacity	$81
Incremental Emissions	$69
Total Retirement Costs	$4,230
Net PVSC (Benefits)/Costs	**$36**

Q. USING THE 2013 MODEL, WHAT IS THE FORESIGHT COST AND VALUE OF THE INCREMENTAL 71 MW?

A. Assuming the total EPU costs were $141 million (22.0 percent), the project shows a net PVSC cost of $6 million, a very small difference between the scenarios. Furthermore, the impact of the EPU is small in the context of the overall Monticello plant. Table 14 summarizes the Strategist results for the 22.0 percent EPU scenario.

Table 14. 2013 Model Foresight at 22.0 Percent

Monticello EPU	PVSC Results $millions	EPU Replacement	PVSC Results $millions
		Replacement Capacity	$60
EPU Capital Cost	$231	Replacement Energy	$184
EPU Incremental Fuel	$63	Incremental Emissions	$44
EPU Total	$294	Total Avoided	$288
		Net PVSC (Benefits)/Costs	$6

In this scenario, the total cost of the EPU is increased to $277 million. Obviously with higher capital cost the project look less attractive. Table 15 shows that the net PVSC impact under the higher cost assumption is $209 million.

Table 15. 2013 Model Foresight at 42.0 Percent

Monticello EPU	**PVSC Results $millions**	**EPU Replacement**	**PVSC Results $millions**
		Replacement Capacity	$60
EPU Capital Cost	$434	Replacement Energy	$184
EPU Incremental Fuel	$63	Incremental Emissions	$44
EPU Total	$497	Total Avoided	$288
		Net PVSC (Benefits)/Costs	**$209**

While this scenario is more expensive, we do not believe that this allocation accurately portrays the avoidable cost of the EPU and fails to take into account the value of the plant as a whole.

b. Implementation Analysis of Incremental 71 MW

Q. DID YOU CONDUCT AN IMPLEMENTATION ANALYSIS FOCUSING ON THE COST AND VALUE OF THE INCREMENTAL 71 MW?

A. Yes. We used the same modeling assumptions as described above for the implementation analysis of the plant as a whole. In this scenario, the analysis compares the cost of the EPU megawatts and the forecasted benefits to the costs of those megawatts plus the sunk cost that had been incurred by that date. Table 16 provides a depiction of how much capital was assumed to be sunk in each year and how much capital was left to be spent (to-go).

Q. WHAT WERE THE RESULTS OF YOUR IMPLEMENTATION ANALYSIS OF THE INCREMENTAL 71 MW?

A. Table 16 summarizes the implementation analysis. As can be seen from the table, the work at Monticello remains cost effective in each of the years that we analyzed. The implication being that in each year, when taking into consideration the capital that had already been spent on the project and the remaining capital to-go, the decision to continue to move forward on the project would have been prudent and in our customers best interest.

Table 16. Implementation Analysis – 71 MW

EPU 22%

Simulation Year	Monticello Life Extension + EPU PVSC $millions	Monticello Life Extension Only + EPU Sunk Costs PVSC $millions	(Benefit) from EPU PVSC $millions
2008	$4,266	$4,456	($190)
2009	$4,338	$4,500	($162)
2010	$3,986	$4,257	($272)
2011	$3,599	$3,810	($212)
2012	$3,593	$3,738	($144)

EPU 42%

Simulation Year	Monticello Life Extension + EPU PVSC $millions	Monticello Life Extension Only + EPU Sunk Costs PVSC $millions	(Benefit) from EPU PVSC $millions
2008	$4,266	$4,301	($35)
2009	$4,338	$4,373	($35)
2010	$3,986	$4,155	($169)
2011	$3,599	$3,759	($161)
2012	$3,593	$3,754	($160)

As can be seen from Table 16, each year along the way, our continued pursuit of the incremental 71 MW was reasonable based on the amount spent to date and the amount remaining toward the $665 million overall cost of the initiative.

VIII. COMPARISON OF MONTICELLO TO PRAIRIE ISLAND

Q. YOU HAVE MENTIONED THE COMPANY'S EPU PROGRAM AT PRAIRIE ISLAND. WHY WAS THAT PROGRAM TERMINATED?

A. On March 30, 2012, the Company filed a notice of Changed Circumstance in the *Prairie Island EPU CON* Docket.[19] In its filing, the Company advised the Commission of the change in size and timing of the Prairie Island program

[19] *Prairie Island EPU CON,* NOTICE OF CHANGED CIRCUMSTANCE, Docket No. E002/CN-08-509 (Mar. 30, 2012).

and also identified changes to the federal licensing process, load forecasts and costs of alternative resource options. This filing prompted a regulatory process over the next six months where the Commission reconsidered whether the EPU activities were still appropriate under the circumstances.

The constructive debate that ensued included discussion of the amount of costs already incurred and the potential costs yet to be incurred if the program were completed. We also analyzed the amount of costs that could be avoided, if the EPU was discontinued. We pointed out that the program was significantly delayed and could encounter significant cost increases. We also described additional benefits that could offset the EPU, in terms of having already obtained 18 MW of additional capacity associated with measurement uncertainty recapture, and the benefits we are already achieving because of fuel changes that allow us to extend our operating cycles.

On December 20, 2012, the Commission terminated the certificate of need issued for the Prairie Island uprate project prospectively.[20] In its Order, the Commission concluded that we demonstrated it was in the public interest to discontinue the uprate project at Prairie Island.[21]

Q. DID THE COMPANY CONSIDER SEEKING LEAVE TO TERMINATE THE CERTIFICATE OF NEED FOR MONTICELLO?

A. No. Monticello was in a very different position than Prairie Island, and we could not have proceeded in the same way.

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[20] *Prairie Island EPU CON,* ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY at 4, Docket No. E002/CN-08-509 (Feb. 27, 2013).
[21] *Id.* at 3.

Q. PLEASE EXPLAIN.

A. We received our certificate of need for Monticello in January 2009. Due to the timing that had been identified for new capacity in our resource plan, we needed to multi-track implementation of the Monticello Program. As a result, we had already begun detailed design and engineering while our certificate of need application was pending so we would be in the position to commence construction almost immediately. We began implementation during the Spring 2009 refueling outage, meaning we started installation of major modifications only a few months after receiving the certificate of need.

By the end of the 2009 outage, we had already spent about $200 million on engineering, licensing and construction, including about $75 million that had been spent in the 2009 outage itself. At that point the Program was roughly on track and had exceeded our forecasts by a relatively small amount. Seeking to withdraw the certificate of need at that time would have been inconsistent with our experience to that point and would have been inconsistent with our desire to upgrade the plant and add incremental capacity. We had no evidence at the time that would contradict the Commission's certificate of need Order.

Prior to the 2011 implementation outage, we had already expended $280 million in furtherance of the Program. Once again, at this point we had no basis to think that we should change course. Further, stopping at that point would have resulted in significant stranded costs. By the end of the 2011 implementation outage, when it became apparent that final costs were going to substantially exceed the original estimates, we had spent $430 million. As shown in the "To-Go" analysis above, with those costs already expended it was cost-effective to continue forward and complete the installations.

Thus, unlike Prairie Island, we did not have a feasible opportunity to revisit whether proceeding remained the best approach.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.