

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

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1 **I. INTRODUCTION AND BACKGROUND**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

9
10 Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCES.

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

14
15 Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCES IN THE AREAS OF
16 RESOURCE PLANNING AND INFRASTRUCTURE PERMITTING.

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

1 Q. DO YOU HAVE EXPERIENCE DIRECTLY RELATED TO THE COMPANY’S NUCLEAR
2 PROGRAM?

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

11

12

II. SUMMARY AND OVERVIEW

13

14 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

22

- Xcel Energy’s State regulatory efforts to obtain a renewed license to
23 operate Monticello through 2030;

24

- The resource planning context that influenced how we implemented
25 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).

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

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

9
10 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

20
21 Resource Planning Issues. Second, I outline the Company's resource planning
22 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 CO₂ and other emissions for use in resource decisions. Any increase in the value ascribed to CO₂ 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)

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

17
18 EPU certificate of need. Third, I will describe the certificate of need process
19 undertaken to seek Commission authority to construct the EPU upgrades in
20 support of increasing the capacity at Monticello by approximately 71 MW.
21 Because of the increased demand shown in our resource plan forecast, we
22 proceeded to seek a certificate of need to add capacity at Monticello (as well as
23 at two other plants). The Commission granted the requested certificate of
24 need on the basis that the Company needed to add resources and the cost of
25 the incremental megawatts at Monticello was a cost-effective option based on
26 the alternatives analysis that was done at the time.

27

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

6
7 This modeling work shows that, while the upgrades were more expensive than
8 we planned, the Monticello power plant remains a cost-effective resource for
9 our customers.

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

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

11 III. REGULATORY CONTEXT

13 A. The Contribution of Xcel Energy’s Nuclear Fleet

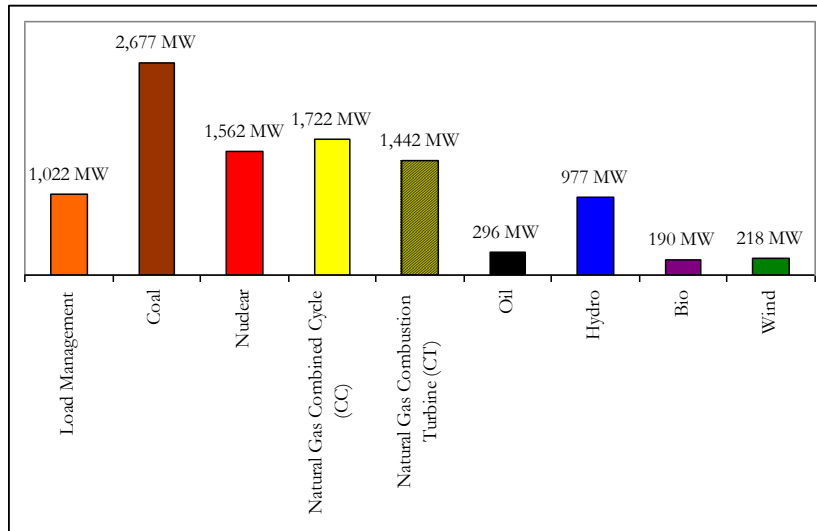
14 Q. PLEASE DESCRIBE THE COMPANY’S GENERATION PORTFOLIO?

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

20
21 One can measure nuclear power’s contribution to Xcel Energy’s generation
22 fleet in two ways. First is a capacity perspective that measures each generating
23 resource’s contribution to meeting our peak customer demand, which typically
24 occurs on a hot summer weekday. Figure 1 shows that on a capacity basis our
25 nuclear fleet is similar in size to our coal and natural gas resources.

1

Figure 1. Xcel Energy Capacity Mix



2

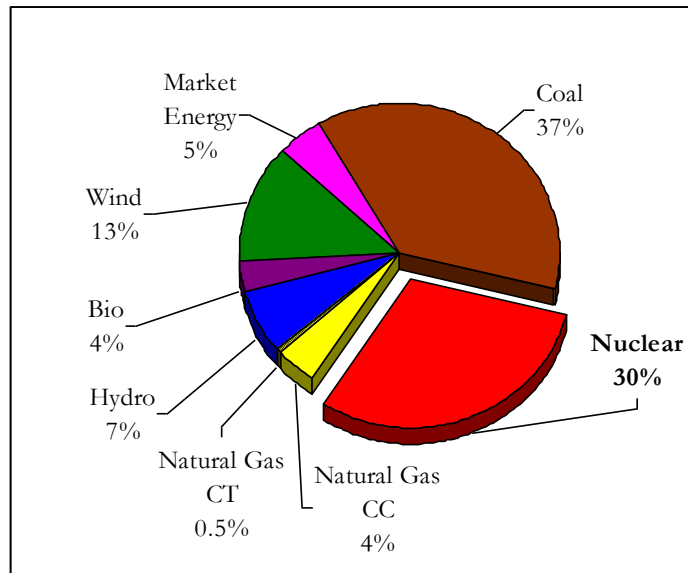
3

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

8

9

Figure 2. Xcel Energy Annual Energy Mix



10

1 Q. PLEASE PROVIDE A SUMMARY OF XCEL ENERGY’S NUCLEAR POWER
2 GENERATION CAPABILITY.

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

5

6 **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

7

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

11

12 Q. DOES NUCLEAR POWER PROVIDE VALUE TO CUSTOMERS?

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

14

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

1

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

2

3

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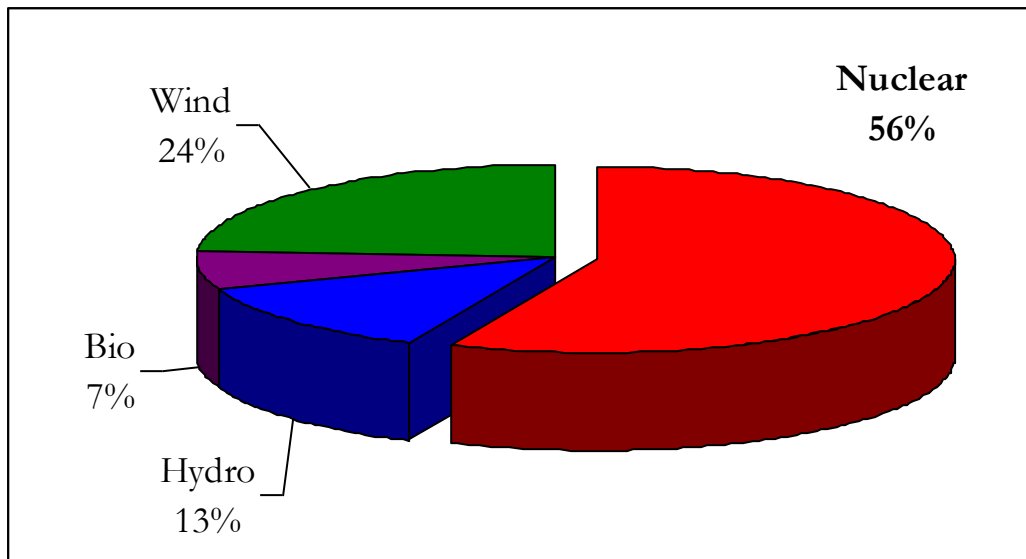
5

6

Second, nuclear generation from the Monticello and Prairie Island plants results in reduced CO₂ emissions. Figure 3 shows the contribution of nuclear in providing carbon-free energy.

7

Figure 3. Carbon-Free Energy Resource



8

9

10

11

12

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.

1 **B. The Contribution of Monticello**

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

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

9
10 First, Monticello is strategically located only 30 miles from our largest load
11 center. This location and the robust transmission system that developed
12 around this and other local generation provide significant reliability benefits to
13 our customers. Maximizing the use of existing infrastructure is an efficient
14 way to provide value to customers. Through our life-cycle management
15 program, we have upgraded Monticello to ensure that these resources remain
16 available to customers at least through 2030. It is in our customers' interest to
17 maintain these assets for the long term.

18
19 Second, the environmental regulations applicable to fossil-fuel generation have
20 been evolving. Indeed, dramatic changes in coal environmental regulations
21 and the potential for more changes present challenges to existing coal
22 generation and make it almost impossible to commit to a new coal plant
23 resource at this time. If nuclear is replaced in the current environment it
24 would be with natural gas generation to be operated as a baseload resource.
25 The fuel diversity offered by nuclear generation is an important part of the
26 Company's generation mix.

27

1 Another benefit is that nuclear generation acts as a hedge against fuel prices
2 and potential future carbon regulations. If the Company had not pursued the
3 20-year license renewal and closed Monticello in 2010, future levels of natural
4 gas consumption and Midcontinent Independent System Operator (“MISO”)
5 market purchases would be higher, creating higher cost uncertainty for our
6 customers. We project that replacing 671 MW of nuclear generation with
7 natural gas generation would increase our annual natural gas usage by 19 bcf
8 or 45 percent. It would also increase our market purchases by approximately
9 850 GWh or 61 percent.

10
11 Fourth, retaining Monticello creates a hedge against potential federal CO₂
12 legislation. It is unclear when significant CO₂ legislation might be imposed
13 and what form it may take (cap and trade, carbon tax, strict annual limits), but
14 retaining Monticello’s 600 MW (through 2013) and 671 MW (from 2014
15 through 2030) will add 4,800-5,400 GWh of carbon-free energy annually
16 reducing our annual CO₂ emission by approximately 2.8 million tons or 14
17 percent, compared to a scenario in which Monticello is replaced by natural gas
18 generation. This will reduce our exposure to carbon regulation and will lower
19 the cost of compliance with any CO₂ goal or target level.

20
21 To illustrate the benefit of retaining Monticello, Table 3 shows the base case
22 volumes of natural gas, market purchases and CO₂ emissions – and the deltas
23 against these factors for the studied projects.

1

Table 3. Monticello’s Hedge Value

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

2

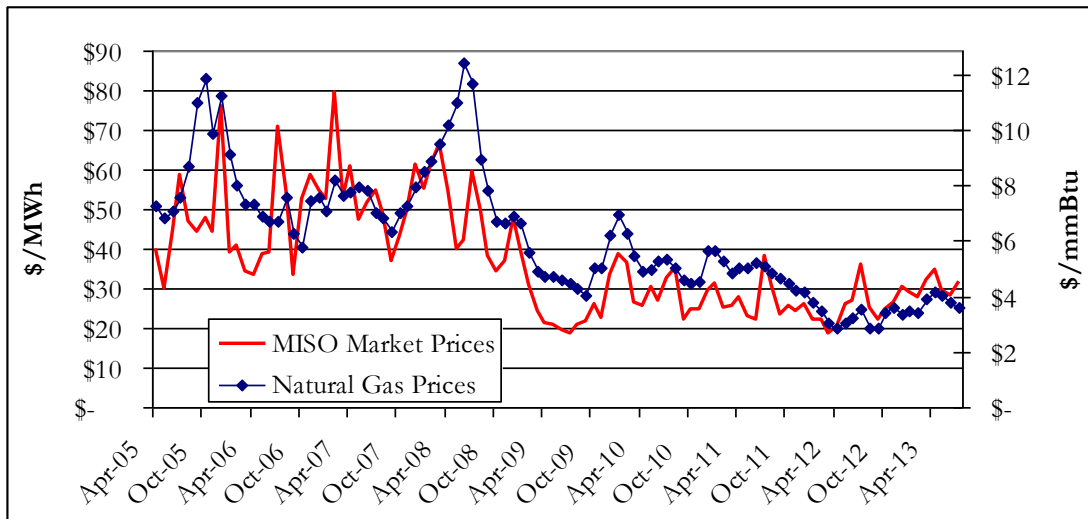
3 Q. WHAT IMPACT DO CURRENT NATURAL GAS PRICES HAVE ON YOUR ANALYSIS?

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

8

9

Figure 4. Gas Prices and Market Prices



10

1 **IV. LICENSE EXTENSION**

2
3 Q. WHEN DID THE COMPANY BEGIN TO EVALUATE OPERATION OF ITS NUCLEAR
4 FLEET BEYOND THE EXPIRATION OF THEIR INITIAL LICENSES?

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

10
11 We recognized that closing the nuclear plants after 40 years and replacing
12 them with new baseload generation would create excess customer costs
13 compared with relicensing the nuclear plants and undertaking the work
14 necessary to keep them in good working order for their extended license
15 period. Our assessment of the plants was that the cores and reactors were
16 sound, and that the power-plant side or “secondary systems” were in
17 reasonably good shape and could be repaired or replaced to support extended
18 operations.

19
20 Many of the plant-side systems at a nuclear plant are similar to the operating
21 equipment of other technologies that produce power from steam, and could
22 be used for extended periods under appropriate circumstances. We
23 reasonably believed that repairing or replacing those secondary systems as
24 necessary to maintain safe and reliable operation was the appropriate approach
25 to keeping nuclear generation as a long-term viable option for our customers.

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

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

10

11 Q. HOW DID CIRCUMSTANCES CHANGE IN 2003?

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

18

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

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

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

13

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

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

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

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

11

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

20

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

1 operating experience at the plant and the NRC environment as it existed at
2 that time.

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

8
9 Q. AT THIS SAME TIMEFRAME, DID THE COMPANY BEGIN ITS EFFORT TO SEEK A
10 LICENSE EXTENSION FROM THE NRC?

11 A. Yes. On March 24, 2005, while our certificate of need was pending, we filed
12 the license renewal application seeking to renew the license at Monticello,
13 allowing us to continue operations of the plant through 2030. The NRC
14 renewed the operating license for Monticello on November 8, 2006. The
15 timeline and activities undertaken as part of the license renewal process can be
16 viewed on the NRC Website at the following link:

17 <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).

1 **V. RESOURCE PLANNING**

2
3 Q. WERE OTHER MINNESOTA REGULATORY PROCEEDINGS ONGOING AT THE
4 TIME THAT CONTRIBUTED TO THE COMPANY’S APPROACH?

5 A. Yes. From 2004 through 2009, the ongoing use of our nuclear fleet was a
6 significant topic of consideration in our resource plan proceedings before the
7 Commission. This debate centered, first, around the value of continued
8 operations of the nuclear units, and, second, around the potential to obtain
9 increased generating capacity from those units to satisfy significant identified
10 baseload capacity needs. In this same timeframe, the Commission was
11 reviewing information about Monticello that showed it to be a cost-effective
12 part of our portfolio for the long-term. This debate continued over two
13 resource plan cycles in 2004-06 and 2007-09.⁵

14
15 Q. PLEASE DESCRIBE HOW THE 2004 RESOURCE PLAN PROCEEDING AFFECTED
16 THE CONSIDERATION OF NUCLEAR OPTIONS.

17 A. In the 2003-2007 timeframe, the Company was experiencing a period of
18 significant load growth. The forecasts at the time showed that we needed a
19 significant amount of new baseload generating capacity in the near-to mid-
20 term. In our 2004 Resource Plan filing, we forecasted an increased demand
21 for up to 1,125 MW of new baseload capacity by 2015.⁶

22
23 Development of new baseload capacity requires long planning horizons. As a
24 result, it was important to move forward promptly to build, buy or otherwise
25 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).

1
2 The 2004 Resource Plan demonstrated that continued operation of our
3 nuclear units through the planning horizon was in our customers' interest
4 since discontinuing use of that capacity would have increased required
5 replacement generation, resulting in higher overall portfolio costs. Our
6 analysis at the time showed that retirement of both Monticello and Prairie
7 Island would cost well over one billion dollars more than continuing to
8 operate them in their existing configurations.⁷

9
10 In addition to continued operations of our existing fleet, the demand forecasts
11 at the time pointed to the need for incremental additional baseload capacity.
12 The 2004 Resource Plan proceeding included a robust discussion of
13 alternatives and potential approaches. As part of those discussions, we
14 advised the Commission of the potential for increasing or "uprating" the
15 capacity of Monticello, Prairie Island and Sherco 3 as another source of
16 increased capacity. The Commission concluded that we should pursue the
17 regulatory approvals necessary to move forward with these projects and
18 ordered us to proceed with exploring additional baseload capacity from these
19 existing generators. In its June 2006 Order approving the 2004 Resource Plan,
20 the Commission required the Company to file for any required Commission
21 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).

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

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

9

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

16

17

VI. EPU CERTIFICATE OF NEED

18

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

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

25

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).

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

5
6 We did not undertake detailed design and engineering at that time to refine the
7 estimates because this would have taken several years and would have been
8 very expensive and essentially infeasible. Further, we believed that this initial
9 estimate was adequate for modeling purposes. The benefit from continued
10 operations at Monticello was such at the time that the lack of precision in the
11 estimate would not have made a material difference, as the benefits were so
12 significant.

13
14 The Company filed its application for certificate of need in Docket No.
15 E002/CN-08-185 on February 14, 2008 (“Monticello LCM/EPU CON”).
16 This application described a series of projects necessary to obtain 71 MW of
17 projected capacity increase and to ensure that that the plant would be able to
18 operate in a safe and reliable manner through 2030.

19
20 At that time, the Company estimated that the overall cost of the initiative
21 would be approximately \$320 million (including a replacement steam dryer
22 that was added to the project). The breakdown of these costs for the
23 purposes of the certificate of need was \$133 million for the EPU and \$189
24 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.

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

5
6 Q. WHY DID THE COMPANY DIVIDE THE COSTS BETWEEN THE LCM AND EPU
7 COMPONENTS OF THE PROGRAM?

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

12
13 However, the Commission's certificate of need rules required that the
14 Commission compare the proposed capacity addition against other alternative
15 sources of capacity. In order to provide the Commission with a basis to
16 compare the additional 71 MW against other alternatives, the Company
17 performed a high-level allocation of costs between the EPU and LCM aspects.
18 The split that was used in the certificate of need was not based on an "avoided
19 cost" analysis but was rather based on a conservative allocation of the
20 installations that are part of the Program. Based on that conservative review,
21 41.6 percent of the costs were allocated to EPU and 58.4 percent allocated to
22 LCM. This rough estimate allowed the Company to undertake Strategist
23 analysis of the hypothetical cost of the incremental megawatts.

24
25 In subsequent proceedings, stakeholders have been interested in the basis for
26 this allocation of costs. Notably, in our recently-completed rate case (Docket
27 E002/GR-12-961), the Administrative Law Judge ("ALJ") Report observes

1 that the Company had not provided an adequate explanation of the division of
2 the costs between the LCM and the EPU components. As part of the current
3 proceeding, therefore, we conducted an analysis of the modifications that were
4 installed. As described in the testimony of Mr. O'Connor, the Company
5 conducted an assessment of what modifications could have been avoided had
6 we not proceeded with the EPU, or conversely, which modifications would
7 have to occur regardless of the EPU. This 'avoided cost' analysis had not
8 been done at the certificate of need stage.

9
10 Q. PLEASE SUMMARIZE THE MODELING RESULTS IN THE CERTIFICATE OF NEED
11 PROCESS THAT SUPPORTED THE COMMISSION'S DECISION TO GRANT THE
12 CERTIFICATE OF NEED.

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

21
22 Q. DID THE COMPANY REVISIT ITS ECONOMIC ANALYSIS IN THE CERTIFICATE OF
23 NEED PROCEEDING?

24 A. Yes. While the Monticello LCM/EPU CON was pending, the United States
25 experienced a significant downturn in the overall economy and entered into
26 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.

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

8
9 Q. PLEASE DESCRIBE THE COMMISSION'S ORDER IN THE EPU CERTIFICATE OF
10 NEED PROCEEDING.

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

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

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

21
22 In November 2009 we advised the Commission that the NRC decided to
23 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.

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

3
4 Second, we filed a formal Notice of Changed Circumstances on November
5 22, 2011, explaining that the Program was delayed due to the impacts of
6 Fukushima and continued delays in the NRC review of our license
7 amendment. We advised the Commission that final implementation of the
8 Program would be delayed until the 2013 scheduled refueling outage at the
9 plant to ensure adequate time to implement all of the components and
10 ongoing safe and reliable operation of the plant. On January 6, 2012, the
11 Commission notified the Company that the proposed change in timing of the
12 Program was acceptable without the need to reopen the certificate of need.¹⁶

13 14 **VII. MODELING CONFIRMS MONTICELLO'S VALUE**

15
16 Q. DID THE COMPANY CONDUCTED AN ANALYSIS OF THE RATEPAYER IMPACTS
17 OF THE MONTICELLO LCM/EPU PROGRAM?

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

21
22 Q. DID THE COMPANY HAVE AN UNDERLYING ASSUMPTION FOR THE MODELING
23 WORK THAT WAS DONE IN SUPPORT OF THIS PROCEEDING?

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

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

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

7
8 Q. WHY IS THIS UNDERLYING ASSUMPTION IMPORTANT TO THIS PROCEEDING?

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

25
26 The Company made all of its upgrades to Monticello with the intention of
27 supporting long-term operations. As a result, we believe our prudence in that

1 endeavor should be judged based upon the value of the whole plant and not
2 just the incremental megawatts. For that analysis, we believe the proper point
3 of comparison is to consider the cost and value of Monticello today against
4 the cost and value associated with retirement in 2010. This 2010 retirement
5 scenario reflects the facts that, had we not undertaken all of the life-cycle
6 management activities described in this proceeding, we could not support
7 long-term operations. Had that been the case, we would not have obtained
8 the license extension.

9
10 **A. Description of Strategist**

11 Q. WHAT IS STRATEGIST?

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

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

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

5
6 Q. HOW DOES THE STRATEGIST MODEL WORK?

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

18
19 For the analysis in this Strategist was first run with Monticello included as an
20 existing resource. Next Monticello was removed from the model and
21 simulation re-run using the various scenarios I will describe in my testimony.

22
23 Q. IS STRATEGIST A WIDELY-USED MODELING TOOL IN THE UTILITY INDUSTRY?

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

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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

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

3
4 2. *Foresight Analysis.* We conducted an analysis of whether Monticello
5 remains cost-effective today based on the \$665 million cost and comparing
6 that to replacement of Monticello with natural gas generation. For this
7 analysis we assumed that, had we not embarked upon the LCM/EPU
8 Program, we would have shut Monticello down in 2010 at the end of its
9 original license since, without the LCM upgrades, it would not have been
10 feasible to operate the plant through 2030.

11
12 3. *Implementation Analysis.* We conducted an annual review of whether, in
13 light of the costs already expended on the Program and the amount of costs
14 remaining to be spent, it was reasonable for the Company to proceed with the
15 Program to completion. This analysis provides an opportunity to consider the
16 value of the Program in light of the Company's actual expenditures in each
17 year. We conducted this analysis three ways. First, we reviewed the value of
18 Monticello in light of the costs "to go" to complete the work at the \$665
19 million level. Second, we did an assessment of the annual value of the
20 Program at \$665 million based simply on considering whether the Program
21 remained cost effective without regard to the costs already incurred. Third,
22 under this analysis, we provide the output of internal modeling work that we
23 conducted in 2010 and 2011 to provide management with an assessment of
24 the costs and value of the Program at that time. All of these analyses are
25 designed to assess whether it would be appropriate to reconsider decisions or
26 change course based on changing circumstances.

27

1 4. *LCM/EPU Split Value.* Finally, we replicate the analysis that was
2 done in the certificate of need proceeding to assess the cost and value of the
3 incremental EPU megawatts (71 MW) using assumed values for the cost of
4 those megawatts. We ran this analysis a number of ways for comparison.
5 First, in preparation for this proceeding, we isolated the avoidable EPU costs
6 that would not have been incurred had we not proceeded with the EPU. This
7 “avoidable EPU” cost is substantially similar to how we analyzed the
8 LCM/EPU costs in the proceeding where we sought authority to cancel the
9 EPU certificate of need for our Prairie Island plant (Docket No. E/002-CN-
10 09- 509 and 510). Mr. O’Connor supports this analysis and shows that 78.0
11 percent of the costs incurred in this Program were unavoidable LCM costs
12 and 22.0 percent of the costs can be seen as avoidable EPU costs. For
13 comparison, we also provide the modeling results using the assumptions used
14 in the certificate of need proceeding – 58.4 percent LCM and 41.6 EPU.
15 Finally, we conducted an implementation analysis of the incremental 71 MW
16 similar to what we provided for the plant as a whole. Once we had the
17 LCM/EPU parameters set, we ran the hindsight, foresight and
18 implementation analyses focusing on the value of the incremental 71 MW.

19
20 I will describe each of the four analyses in the following sections.

21
22 1. *Hindsight Analysis – 2008 Value at \$665 Million Cost*

23 Q. WHAT WAS THE RESULT OF YOUR HINDSIGHT ANALYSIS?

24 A. Had we known in 2008 that the initiative would cost \$665 million, Monticello
25 remained a valuable resource for our customers. Taking into account all of
26 these costs, Monticello as a whole provides \$1,311 million customer savings

1 on a PVSC basis compared to a natural gas alternative based on 2008
2 conditions.

3
4 Q. WHY DID YOU CONDUCT AN ANALYSIS OF THE VALUE OF THE OVERALL
5 PROGRAM AT \$665 MILLION?

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

12
13 Q. WHAT IS THE COST THAT IS APPROPRIATE TO USE FOR PURPOSES OF
14 COMPARISON WITH THE \$665 MILLION?

15 A. Prior to the 2008 certificate of need proceeding, the Company had authorized
16 \$274 million for this initiative. In addition, during the certificate of need
17 proceeding we determined that it would be necessary to add a new steam dryer
18 to the list of projects, bringing the total up to about \$302 million. These
19 numbers were in 2006 dollars. Escalated, the overall cost level that is
20 appropriate for comparison is about \$320 million. This is an appropriate cost
21 that can be used for comparison purposes.

22
23 Q. PLEASE DESCRIBE THE MODELING WORK YOU DID TO ASSESS THE VALUE OF
24 THE MONTICELLO LCM/EPU PROGRAM IN 2008, ASSUMING \$665 MILLION
25 COST HAD BEEN KNOWN AT THAT TIME.

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

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

- 3 • Adjust the costs of the Monticello LCM/EPU Program to reflect the
4 \$665 million incurred through August 31, 2013.
- 5 • Added a forecast of additional capital investments necessary at the plant
6 from 2013-2030.
- 7 • For comparison purposes we developed a retirement and replacement
8 scenario that simulated the shutdown of Monticello in 2010. For this
9 scenario we added the cost of a new natural gas combined cycle plant to
10 replace Monticello and the costs for decommissioning of the plant in
11 2011.

12
13 Q. WHAT WERE THE RESULTS OF THE ANALYSIS ?

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

1 of natural gas in 2008 was very bleak. The output of this analysis is shown in
 2 Table 5.

3
 4 **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 Decomissioning (2031)	\$148	Monti Decomissioning (2011)	\$423
EPU/LCM+On-Going Capital	\$1,266	Replacement Capacity	\$1,615
Monti O&M	\$1,959	Replacement Energy	\$2,954
<u>Monti Fuel</u>	<u>\$893</u>	<u>Incremental Emissions</u>	<u>\$585</u>
Monti Total	\$4,266	Total Retirement Costs	\$5,577
		Net PVSC (Benefit)/Costs	(\$1,311)

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

9
 10 *2. Foresight Analysis – 2013 Value at \$665 Million Cost*

11 Q. WHAT WAS THE RESULT OF YOUR FORESIGHT ANALYSIS?

12 A. In 2013, had we known that the initiative would cost \$665 million, Monticello
 13 remains a valuable resource for our customers. Taking into account all of
 14 these costs, Monticello as a whole provides \$174 million customer savings on
 15 a PVSC basis compared to a natural gas alternative based on 2008 conditions.
 16 We also ran low/high natural gas and no/high carbon sensitivities as well as a
 17 10-year extension scenario. These show that the value of the plant is sensitive
 18 to the volatility of gas and carbon costs. Even a modest increase in natural gas
 19 or carbon costs would magnify the value of retaining Monticello’s carbon free
 20 generation for as long as reasonably possible.

1 Q. PLEASE DESCRIBE THE FORESIGHT ANALYSIS.

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

7

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

14

15 Nevertheless, we believe this analysis provides a useful data point for the
16 Commission's consideration. This analysis shows that \$665 million in support
17 of the long-term viability of Monticello is more cost-effective in 2013
18 compared to an early shut-down of the plant. The PVSC difference of these
19 two scenarios shows Monticello provides \$180 million in savings through
20 2030.

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

3 A. We used the same modeling assumptions that were used in the model for the
4 pending competitive acquisition docket.¹⁷ That Strategist model included the
5 following important input assumptions:
6

- 7 • *Load Forecast.* The load forecast used in this model was developed in the
8 spring of 2013 and reflects our most current assessment of the impacts of
9 conservation (Demand Side Management (“DSM”)) on total customer
10 demand. The forecasted peak demand during the resource acquisition
11 period is; 2017 – 9,500 MW, 2018 – 9,590 MW, and 2019 – 9,676 MW.
12
- 13 • *Load Management Forecast.* The forecast of load management or direct load
14 control programs was developed in spring of 2013. Total load
15 management is 985 MW in 2013 and grows at an average rate of one
16 percent annually through 2020 reaching 1056 MW in that year.
17
- 18 • *Reserve Margin.* To set reliability standards the model uses a reserve margin
19 of 3.79 percent as established in MISO’s November 2011 loss of load
20 expectation (“LOLE”) report.
21
- 22 • *Natural Gas & MISO Market Prices.* The model includes natural gas and
23 market pricing from late July 2013. The updated natural gas forecasts
24 starts at \$3.72/mmBtu and escalates at 4.6 percent through 2030. The
25 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.

1 \$5.35/mmBtu. The 2013 price of market energy is \$23.12/MWh for off
2 peak and \$35.89/MWh for on peak. Market energy escalates at 4.1 percent
3 and the levelized prices are \$31.74/MWh for off peak and \$49.72/MWh
4 for on peak.

- 5
- 6 • *Emission Pricing.* The base model includes the midpoint values for the
7 Commission established externality values, including \$21.50/ton for CO2
8 starting in 2017.
- 9
- 10 • *Accredited Capacity.* The summer firm capacity values used in the model
11 reflect the unforced capacity values (“UCAP”) used in this summer’s
12 MISO Module-E resource adequacy standard.
- 13
- 14 • *Retirements.* The model includes the retirement of Black Dog 3 and 4 in the
15 spring of 2015 for compliance with Environmental Protection Agency’s
16 Mercury and Air Toxins rule (“MATS”). The model also assumes the
17 retirement of Key City and Granite City at the end of 2016.
- 18
- 19 • *Resource Additions.* We have budgeted capital for repair and return to
20 service of our French Island 3 peaking unit in spring of 2016, and its return
21 is reflected in the Strategist model.
- 22
- 23 • *Wind.* The model includes the 750 MW of wind recently proposed by the
24 Company. In addition the model contains a long-term wind expansion
25 plan designed to achieve and then maintain our 30 percent renewable
26 energy standard. The long term wind expansion plan starts in 2022 with a
27 100 MW addition and grows to 1,500 MW of additional wind by 2030.

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- *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

1 starting in that month. The LCM/EPU investment is depreciated over the
2 remaining life of the plant.

- 3
- 4 • *On-Going Capital.* The capital forecast used in the Strategist model was
5 developed in August of this year. From 2014 through 2030 the average
6 annual capital investment is \$24 million per year for a total of \$433 million
7 in total additional investments over the remaining life of the plant.
8
 - 9 • *Operating and Maintenance Expenses.* The plant O&M budget forecast was
10 also updated in August of this year. The O&M forecast used in Strategist
11 averages \$145 million per year from 2013 through 2030.
12
 - 13 • *Decommissioning Costs.* The plant's decommissioning costs were based on
14 the Company's Triennial Decommissioning Accrual Update. The total
15 decommissioning costs included in the model are \$978 million in terms of
16 2011 dollars. After applying escalation factors, the total decommissioning
17 expenses total \$2.6 billion for the 2030 retirement scenario. To ensure that
18 the decommissioning fund is adequate to support these expenditures, the
19 Monticello plant is assumed to accrue \$14.3 million from 2013 through
20 2030.
21
 - 22 • *Employee Retention Expense.* Our initial evaluation of the license renewal at
23 Monticello included in employee retention cost of \$45-\$90 million.
24 Recently Dominion stated in their October 25, 2012 Third Quarter Form
25 10Q report that the decommissioned Kewaunee plant experienced
26 approximately \$50 million in employee retention costs. For the Strategist
27 analysis we included \$50 million in employee retention costs that are

1 spread equally over the last two years of operation. The \$50 million cost is
2 assumed to be in 2013 dollars and for the 2030 retirement scenario the \$50
3 million was escalated at 2.51 percent, which is our base assumption for
4 labor cost inflation. I note that Dominion also reported a write down of
5 materials and supplies inventories of \$33 million and a \$24 million charge
6 related to severance costs. Xcel Energy anticipates it would have similar
7 types of costs in an early-shutdown scenario. However, since we have not
8 previously analyzed these two categories of costs, we have not included
9 them in the Strategist analysis but recognize costs of this type would likely
10 occur.

11
12 Q. WHAT WAS THE RESULT OF THIS ANALYSIS?

13 A. The Strategist results demonstrate that even with today's low gas prices the
14 \$665 million investment for Monticello's LCM and EPU Program is still cost
15 effective and creates a net PVSC savings of \$174 million. The forecasted cost
16 of replacement energy fell by over \$1 billion as a result of lower natural gas
17 prices. This was partially offset by lower forecasted O&M at Monticello. The
18 2008 model used an average annual fixed O&M of \$165 million per year. This
19 forecast was developed as part of the 2007 resource plan, and because life
20 extension of Monticello was not an issue studied in that proceeding the O&M
21 forecast was not particularly refined or thoroughly reviewed. For our 2013
22 analysis a new forecast of fixed O&M was developed by senior management
23 who oversee our nuclear facility. This refined forecast averages \$145 million
24 per year. Table 6 provides the details of our updated Monticello life extension
25 analysis.

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

Monticello Life Extension+ EPU	PVSC Results \$millions	Monticello Retirement and Replacement	PVSC Results \$millions
Monti Decomissioning (2031)	\$148	Monti Decomissioning (2011)	\$419
EPU/LCM+On-Going Capital	\$1,397	Replacement Capacity	\$1,349
Monti O&M	\$1,720	Replacement Energy	\$1,945
<u>Monti Fuel</u>	<u>\$688</u>	<u>Incremental Emissions</u>	<u>\$412</u>
Monti Total	\$3,952	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:

- *CO₂ Planning Value Sensitivity.* The Commission set the value range for CO₂ 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.

- 1 • *10-Year Extension.* This scenario assumes that Monticello is granted
 2 authority to operate for an additional 10 years from 2030 to 2040. We
 3 used the same forecast as with the 2013 scenarios described above with the
 4 following additional refinements: for capital expenditures, we used an
 5 escalated average and then included a three-year capital reduction in the
 6 final three years to simulate end of life. For O&M, we simply extended the
 7 2013 model assumptions at the average growth rate.

8
 9 Table 7 provides the results of this sensitivity analysis.

10
 11 **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)

12
 13 As can be seen from Table 7, these sensitivities create a significant swing in
 14 the value of Monticello when modeled under 2013 conditions.

- 15
 16 • *CO₂ Sensitivities.* In our base case analysis, we included the mid-point of the
 17 carbon values ordered by the Commission to be included in our modeling.
 18 Due to the uncertainty of future CO₂ regulation, it is appropriate to
 19 consider the costs of resources with high and low assumptions for carbon
 20 costs. These sensitivities show that the current value of Monticello
 21 compared to natural gas resources on a total plant basis varies significantly
 22 depending upon the assumption used. This variability and uncertainty

1 around the impact of carbon costs highlights the value of nuclear as a
2 carbon-free resource as, regardless of the cost ascribed to CO₂, nuclear
3 generation does not contribute to the increase in carbon emissions.

- 4
- 5 • *Natural Gas Sensitivities.* This evaluation is very sensitive to changing natural
6 gas prices. Natural gas prices are currently at historically low levels, and it
7 seems unlikely that they will fall much further. To the contrary, it is more
8 likely that natural gas prices will stay at about their current levels or rise
9 during the remainder of Monticello's life. Even a small increase in natural
10 gas prices increases the value of continued nuclear generation. This
11 illustrates the value of having nuclear generation as a fuel hedge.
- 12
- 13 • *10-Year Extension.* If Xcel Energy is able to continue operating Monticello
14 beyond 2030 without extraordinary expenditures, customers will realize
15 significant savings based on conditions predicted in 2013. While it is not
16 possible to say at this time whether a further extension may be available or
17 reasonable at the time, this scenario suggests that continuing to include
18 nuclear generation in our resource mix remains an attractive supply option
19 and preserves what may be an even more valuable component of our fleet
20 in years to come.

21 3. *Implementation Analysis*

22 Q. WHAT WAS THE RESULT OF YOUR IMPLEMENTATION ANALYSIS?

23 A. This analysis provides a look at our actual annual investment in the Program
24 and assess whether it remained cost effective to continue forward with
25 implementation. We reviewed this taking into account our sunk costs and also
26 without factoring those sunk costs into the mix. On both bases, the analyses
27

1 show that it was reasonable for the Company to continue forward with the
2 Program.

3
4 Q. WHAT IS THE IMPLEMENTATION ANALYSIS?

5 A. Installation of the modifications in furtherance of the LCM/EPU Program
6 took approximately five years from 2009 through 2013. This implementation
7 analysis provides information on whether the investment over time remained
8 cost effective in light of the changes in the energy markets that have occurred
9 in the past five years. We provided this analysis using three different sets of
10 assumptions: (i) annual look at the value of Monticello at \$665 million taking
11 into account the amounts actually incurred at the time; (ii) annual look at the
12 value of Monticello at \$665 million without taking into account amounts
13 actually incurred; and (iii) review of internal analyses conducted in 2010 and
14 2011 to consider the ongoing value of the initiative.

15
16 a. Incremental Cost Analysis

17 Q. PLEASE DESCRIBE THE INCREMENTAL COST ANALYSIS.

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

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

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

13
14 **Table 8. Assumed Capital on an Annual Basis**

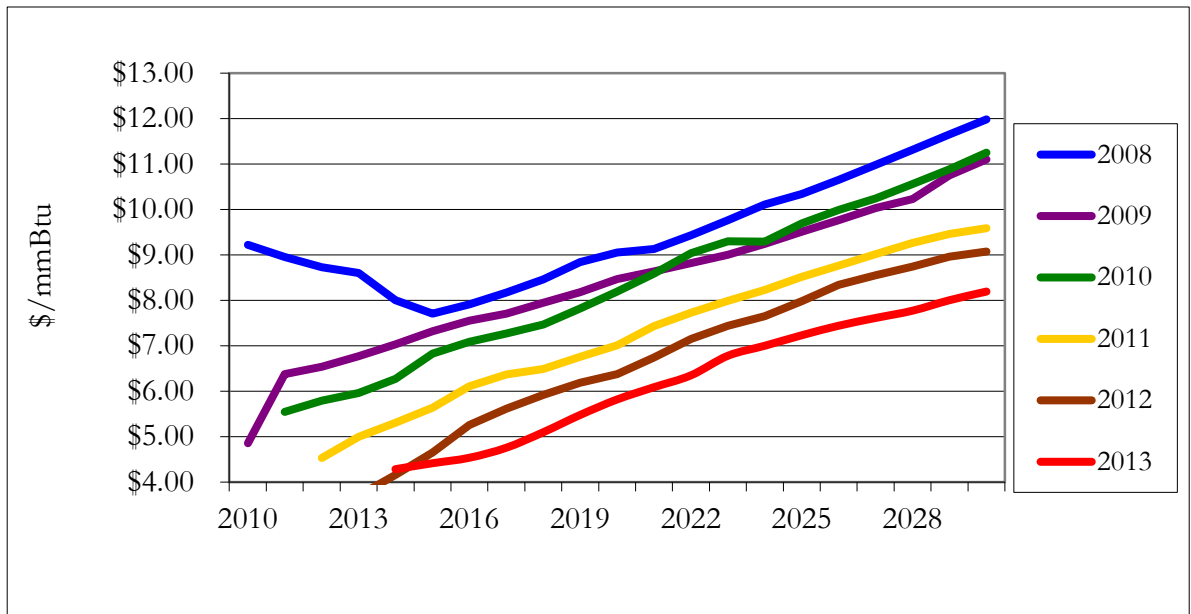
Simulation Year	EPU/LCM Spent to Date (sunk cost)	Remaining EPU/LCM Capital (to-go)	Total Capital
2008	\$97M	\$568M	\$665M
2009	\$216M	\$449M	\$665M
2010	\$292M	\$373M	\$665M
2011	\$466M	\$199M	\$665M
2012	\$513M	\$152M	\$665M
2013	\$665M	\$0M	\$665M

15
16
17 Q. HOW WERE THE ANNUAL SIMULATIONS CONDUCTED?

18 A. We began by collecting representative Strategist base cases from each year
19 2008 through 2013. These models include assumptions regarding load
20 growth, fuel price, and emissions costs that were current as of that year. One
21 model assumption that has particular impact on the EPU/LCM analysis is the
22 cost of the natural gas that would be used as a source of replacement energy if

1 the plant had been retired. From 2008 to 2013 forecasts of natural gas prices
2 have fallen steadily. Figure 5 illustrates that since 2008 the forecasted price of
3 natural gas has fallen over \$3/mmBtu.
4
5

Figure 5. Natural Gas Price Forecast



6
7
8 For each simulation we added the total capital cost of \$665 million for
9 LCM/EPU Program and had Strategist calculate the corresponding revenue
10 requirements based on the financial assumptions that were used in the models
11 at the time. We also added the cost of decommissioning of the plant in 2031.
12

13 For the retirement and replacement scenario, we added the sunk costs
14 associated with the LCM/EPU Program but then specified that Monticello
15 retires with associated decommissioning costs, and is replaced with a natural
16 gas combined cycle plant. The Strategist simulation then calculated the
17 revenue requirements for the replacement combined cycle and the total cost

1 of replacement energy. The Strategist models used in the implementation
2 analysis were:

- 3 • 2008: September 2008 Resource Plan Reply Comment model;
- 4 • 2009: September 2009 Black Dog Analysis model;
- 5 • 2010: July 2010 Resource Plan model;
- 6 • 2011: September 2011 Resource Plan Update model;
- 7 • 2012: September 2012 Prairie Island EPU re-evaluation proceeding
8 model; and
- 9 • 2013: September 2013 Competitive Resource Acquisition model

10
11 Q. WHAT WERE THE RESULTS OF YOUR IMPLEMENTATION ANALYSIS?

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

1

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)

2

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

7

8 b. Annual Review

9

9 Q. PLEASE DESCRIBE THIS ANNUAL REVIEW ANALYSIS YOU DID.

10

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

14

15 Q. WHY DID YOU DO THIS ANALYSIS?

16

A. Essentially this is implementation analysis without taking the benefit of
17 accounting for the removal of sunk costs. This analysis assumes perfect
18 foresight as to the changes in the market and cost of the Program. Obviously

1 we could not have had perfect foresight. Nevertheless, this analysis allows us
 2 to view whether, at certain milestones along the way, it might have made sense
 3 not to reevaluate the project based on current circumstances. With perfect
 4 foresight, we might have been able to predict the changes that occurred in
 5 2009-11 (with regard to shrinking sales forecasts and reduced natural gas
 6 prices) and assessed whether our work at Monticello, at \$665 million,
 7 remained in our customers' interest.

8
 9 Q. WHAT WAS THE OUTCOME OF THIS ANALYSIS?

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

11
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)

12
 13 Q. HOW DID YOU CONDUCT THIS ANALYSIS?

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

16
 17 Q. PLEASE EXPLAIN THESE RESULTS.

18 A. The variability in this Table is a function of the inputs into the legacy models
 19 and the impact of falling natural gas prices. In 2009 the value of Monticello

1 fell when judged against the 2009 vintage model. However, in 2010 and 2011,
2 we revised our capital and O&M assumptions for Monticello downward. This
3 had the impact of increasing the benefit of retaining the Program. By
4 contrast, in 2012 when natural gas prices fell dramatically, the value of
5 Monticello fell correspondingly.

6
7 Q. I NOTE THAT THE 2013 LINE FROM TABLE 9 AND TABLE 10 DO NOT MATCH
8 AND THAT THE COST OF RETIREMENT AND REPLACEMENT IS APPROXIMATELY
9 \$1 BILLION DIFFERENT ON A PVSC BASIS. CAN YOU EXPLAIN THE
10 DIFFERENCE?

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

1 c. Internal Analyses

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

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

15
16 The second analysis was conducted in May 2011, after the 2011
17 implementation outage.¹⁸ This internal analysis utilized the original model
18 used to evaluate the EPU Program in 2008. At the time we had identified an
19 additional \$79 million in capital above our original estimate. The analysis
20 indicated that even if the entire \$79 million was attributed to the EPU
21 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.

1 4. *Incremental Value of EPU Megawatts*

2 Q. WHAT WAS THE RESULT OF YOUR INCREMENTAL ANALYSIS?

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

7
8 Q. WHY DID YOU CONDUCT AN ANALYSIS OF THE VALUE OF THE INCREMENTAL
9 EPU MEGAWATTS?

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

18
19 Q. HOW DID THE COMPANY CHOOSE THE LEVELS OF LCM AND EPU COSTS FOR
20 PURPOSES OF THIS ANALYSIS?

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

23
24 First, Mr. O'Connor's testimony provides an analysis of the "avoidable EPU"
25 costs and those LCM costs that would have been unavoidable even if we had
26 not undertaken the EPU. Using that avoidable EPU cost analysis, the
27 Company allocates 22.0 percent of the costs to the avoidable EPU activities,

1 and 78.0 percent to LMC costs that would have been incurred anyway. Table
2 6 provides the total capital amounts associated with these LCM/EPU splits.

3
4 Second, during the EPU certificate of need proceeding, our high level
5 estimates implied an allocation of 41.6 percent of the costs to the EPU and
6 58.4 percent to the LCM activities. While this split was not intended to
7 portray an avoided cost analysis, it is the split that was used in the certificate of
8 need proceeding and was a subject of our 2013 test year rate case (Table 11).

9
10 **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%)

11
12 Q. WHY DID YOU NOT FOCUS ON THE INCREMENTAL COST OF THE EPU IN YOUR
13 ANALYSIS?

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

20
21 Q. HOW WAS STRATEGIST USED TO EVALUATE THE MONTICELLO EPU?

22 A. For this analysis we used the same 2013 model and assumptions that I
23 previously described. We began with a base case that included either 58.4
24 percent or 78.0 percent of the total \$665 million LCM/EPU cost. In this base

1 case Monticello is not uprated and the net generating capacity remains at 585
2 MW through 2030. This base case is compared to the scenario where the full
3 \$665 million is spent and the plant's capacity increases by 71 MW to 656 MW
4 starting January 1, 2014.

5
6 Comparison of these scenarios provides a cost/benefit estimates of the EPU
7 at a total cost of \$146 million (22.0 percent) and at \$277 million (41.6 percent).

8
9 a. Value of 71 MW

10 Q. WHAT WERE THE RESULTS OF THE EPU ANALYSIS IN STRATEGIST FOR THE
11 78.0 PERCENT LCM/22.0 PERCENT EPU CASE?

12 A. The Strategist simulations showed that at a total capital cost of \$146 million
13 (22.0 percent) the EPU project resulted in a net increase in PVSC. Costs of
14 the EPU consist only of revenue requirements that result from the capital
15 invested and higher fuel costs associated with the larger capacity and
16 generation output. If the EPU had not been implemented the incremental
17 capacity would have likely been replaced with additional peaking capacity and
18 the energy from the EPU would have been replaced with a mixture of higher
19 generation from existing plants and additional purchases from the MISO
20 market.

21
22 Q. USING THE 2008 MODEL, WHAT IS THE HINDSIGHT COST AND VALUE OF THE
23 INCREMENTAL 71 MW?

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

1
2

Table 12. 2008 Model Hindsight – 22 Percent EPU

Monticello Life Extension + EPU	PVSC Results \$millions	Monticello LCM Only 58%	PVSC Results \$millions
Monti Decommissioning (2031)	\$148	Monti Decommissioning (2031)	\$148
EPU/LCM+On-Going Capital	\$1,266	EPU/LCM+On-Going Capital	\$1,057
Monti O&M	\$1,959	Monti O&M	\$1,954
<u>Monti Fuel</u>	<u>\$893</u>	Monti Fuel	\$812
Monti Total	\$4,266	Replacement Energy	\$295
		Replacement Capacity	\$81
		<u>Incremental Emissions</u>	\$69
		Total Retirement Costs	\$4,417
		Net PVSC (Benefits)/Costs (\$151)	

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

7
8

Table 13. 2008 Model Hindsight – 42 Percent EPU

Monticello Life Extension + EPU	PVSC Results \$millions	Monticello LCM Only 58%	PVSC Results \$millions
Monti Decommissioning (2031)	\$148	Monti Decommissioning (2031)	\$148
EPU/LCM+On-Going Capital	\$1,266	EPU/LCM+On-Going Capital	\$870
Monti O&M	\$1,959	Monti O&M	\$1,954
<u>Monti Fuel</u>	<u>\$893</u>	Monti Fuel	\$812
Monti Total	\$4,266	Replacement Energy	\$295
		Replacement Capacity	\$81
		<u>Incremental Emissions</u>	\$69
		Total Retirement Costs	\$4,230
		Net PVSC (Benefits)/Costs \$36	

9

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

12 A. Assuming the total EPU costs were \$141 million (22.0 percent), the project
13 shows a net PVSC cost of \$6 million, a very small difference between the
14 scenarios. Furthermore, the impact of the EPU is small in the context of the

1 overall Monticello plant. Table 14 summarizes the Strategist results for the
 2 22.0 percent EPU scenario.

3 **Table 14. 2013 Model Foresight at 22.0 Percent**

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

4
 5 In this scenario, the total cost of the EPU is increased to \$277 million.
 6 Obviously with higher capital cost the project look less attractive. Table 15
 7 shows that the net PVSC impact under the higher cost assumption is \$209
 8 million.

10 **Table 15. 2013 Model Foresight at 42.0 Percent**

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

11
 12 While this scenario is more expensive, we do not believe that this allocation
 13 accurately portrays the avoidable cost of the EPU and fails to take into
 14 account the value of the plant as a whole.

1 b. Implementation Analysis of Incremental 71 MW

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

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

10
11 Q. WHAT WERE THE RESULTS OF YOUR IMPLEMENTATION ANALYSIS OF THE
12 INCREMENTAL 71 MW?

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

1

Table 16. Implementation Analysis – 71 MW

EPU 22%

Simulation Year	Monticello Life Extension + EPU	Monticello Life Extension Only + EPU Sunk Costs	(Benefit) from EPU
	PVSC \$millions	PVSC \$millions	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	Monticello Life Extension Only + EPU Sunk Costs	(Benefit) from EPU
	PVSC \$millions	PVSC \$millions	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)

2

3

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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

10

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

11

12

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

13

14

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

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

5
6 The constructive debate that ensued included discussion of the amount of
7 costs already incurred and the potential costs yet to be incurred if the
8 program were completed. We also analyzed the amount of costs that could be
9 avoided, if the EPU was discontinued. We pointed out that the program was
10 significantly delayed and could encounter significant cost increases. We also
11 described additional benefits that could offset the EPU, in terms of having
12 already obtained 18 MW of additional capacity associated with measurement
13 uncertainty recapture, and the benefits we are already achieving because of
14 fuel changes that allow us to extend our operating cycles.

15
16 On December 20, 2012, the Commission terminated the certificate of need
17 issued for the Prairie Island uprate project prospectively.²⁰ In its Order, the
18 Commission concluded that we demonstrated it was in the public interest to
19 discontinue the uprate project at Prairie Island.²¹

20
21 Q. DID THE COMPANY CONSIDER SEEKING LEAVE TO TERMINATE THE
22 CERTIFICATE OF NEED FOR MONTICELLO?

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

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.

1 Q. PLEASE EXPLAIN.

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

10

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

19

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

28

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

3

4

IX. CONCLUSION

5

6 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

7 A. Yes.