BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

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	MPUC Docket No. E002/CI-13-754 OAH Docket No. 48-2500-31139

DIRECT TESTIMONY AND ATTACHMENTS OF WILLIAM R. JACOBS, JR., PH.D.

ON BEHALF OF

THE DIVISON OF ENERGY RESOURCES OF THE MINNESOTA DEPARTMENT OF COMMERCE

JULY 2, 2014

PUBLIC DOCUMENT

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is William R. Jacobs, Jr., Ph.D. I am an Executive Consultant with GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia, 30067. I work with Mr. Mark W. Crisp of Global Water and Energy Consulting, LLC.

Q. Whom are you representing in this proceeding?

A. I am representing the Minnesota Department of Commerce, Division Office of Energy Resources (Department).

Q. What is your assignment in this proceeding?

A. My assignment is to assist Department of Commerce personnel in conducting an independent investigation of cost overruns on the Monticello Life Cycle Management / Extended Power Uprate project.

Q. Dr. Jacobs, please summarize your educational background and experience.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered Professional Engineer and a member of the American Nuclear Society. I have more than thirty years of experience in the electric power industry including more than twelve years of nuclear power plant construction and start-up experience. I have participated in the construction and start-up of seven nuclear power plants in this country and overseas in management positions including start-up manager and site manager. As a loaned employee to the Institute of Nuclear Power Operations (INPO), I participated in the Construction Project Evaluation Program, performed operating plant evaluations and assisted in development of the Outage Management Evaluation Program.

Since joining GDS Associates, Inc. in 1986, I have participated in rate case and litigation support activities related to power plant construction, operation and decommissioning. I have evaluated nuclear power plant outages at numerous nuclear plants throughout the United States. I served on the management committee of Plum Point Unit 1, a 650 Megawatts Electric (MWe) coal fired power plant. As a member of the management committee, I assisted in providing oversight of the Engineering, Procurement and Construction (EPC) contractor for this project. My resume is included in DOC Ex. ___ at STF-SR/WRJ-1.

Q. What is your experience related to evaluation of life cycle management (LCM) and extended power update (EPU) projects for nuclear power plants?

A. I have extensive experience in evaluation of life cycle management and extended power uprate projects. Since 1988 I have been assisting Corn Belt Power Cooperative (Corn Belt) and Central Iowa Power Cooperative (CIPCO) in monitoring the operation of the Duane Arnold Energy Center (DAEC) of which Corn Belt and CIPCO are minority owners. The DAEC is a Boiling Water Reactor of similar size and vintage as Monticello. The DAEC has recently completed an extended power uprate and a license renewal project. I closely monitored these projects for Corn Belt and CIPCO.

I have also assisted the Florida Office of Public Counsel in evaluation of extended power uprates at five nuclear units – St. Lucie 1 and 2, Turkey Point 3 and 4 and Crystal River 3. I provided testimony on these projects before the Florida Public Service Commission in docket numbers 100009-EI, 100010-EI, 100011-EI, 100012-EI and 100013-EI. In these evaluations, I investigated the causes of the large cost overruns experienced on these projects.

Q. You mention your work assisting the Florida Office of Public Counsel in evaluating Florida Power and Light's St. Lucie and Turkey Point EPU projects. Did you identify any similarities between these projects and the Monticello LCM / EPU project?

A. Yes, I concluded that the planning and results of these two projects are very similar.

- Both utilized an expedited approach in which design, procurement and construction were being done in parallel.
- Both projects used very little contingency in their initial cost estimate given the high amount of uncertainty in the projects.
- Both companies greatly underestimated the amount of work and the difficulty of the conditions that would be encountered in implementing the required modifications.
- Both projects far exceeded the initial budget estimates.

II. BRIEF HISTORY OF THE LCM / EPU PROJECT

Q. Please provide a brief history of the LCM / EPU project at Monticello.

A. After 1994 and prior to 2003, Minnesota law made it very difficult to extend a nuclear power plant's operating license. Xcel had a policy of deferring capital projects, expecting that the plant would be shut down and decommissioned in 2010. Monticello's net plant in rate base had depreciated to $153 million by 2007, thus limiting the amount that could be earned on a potentially risky nuclear plant. In 2003, Minnesota law changed, making it possible to obtain permission to extend the operating license for 20 years. Xcel then set out to obtain permission from the Minnesota Public Utilities Commission (Commission) and the Nuclear Regulatory Commission (NRC) to extend the operating license to operate Monticello for another 20 years. Xcel obtained this permission from both regulatory bodies in 2006.

In 2004 Xcel began to investigate the possibility of also accomplishing an EPU that would increase power output from the plant to 120 percent of the original 1971 level, from 564 MW to 671 MW. (Monticello had already been uprated by 6.3 percent, from 564 MW to 600 MW in 1998; this EPU would be an additional 13 percent of the original 564 MW level.)

Q. How much did Xcel estimate that the EPU would cost?

A. A brief history of project cost estimates and a list of significant decision points is provided by the following timeline. I note that Department Witness Mr. Christopher Shaw discusses Xcel's communication of these cost increases with Minnesota's regulatory agencies; Department Witness Ms. Nancy Campbell discusses how Xcel's current estimated cost understates the full cost of the project. Unfortunately, I note that the information listed below is trade-secret since Xcel designated all of the information below as trade-secret in its response to the Department's information request. It is my understanding that Department Witness Mr. Shaw discusses the issue further.

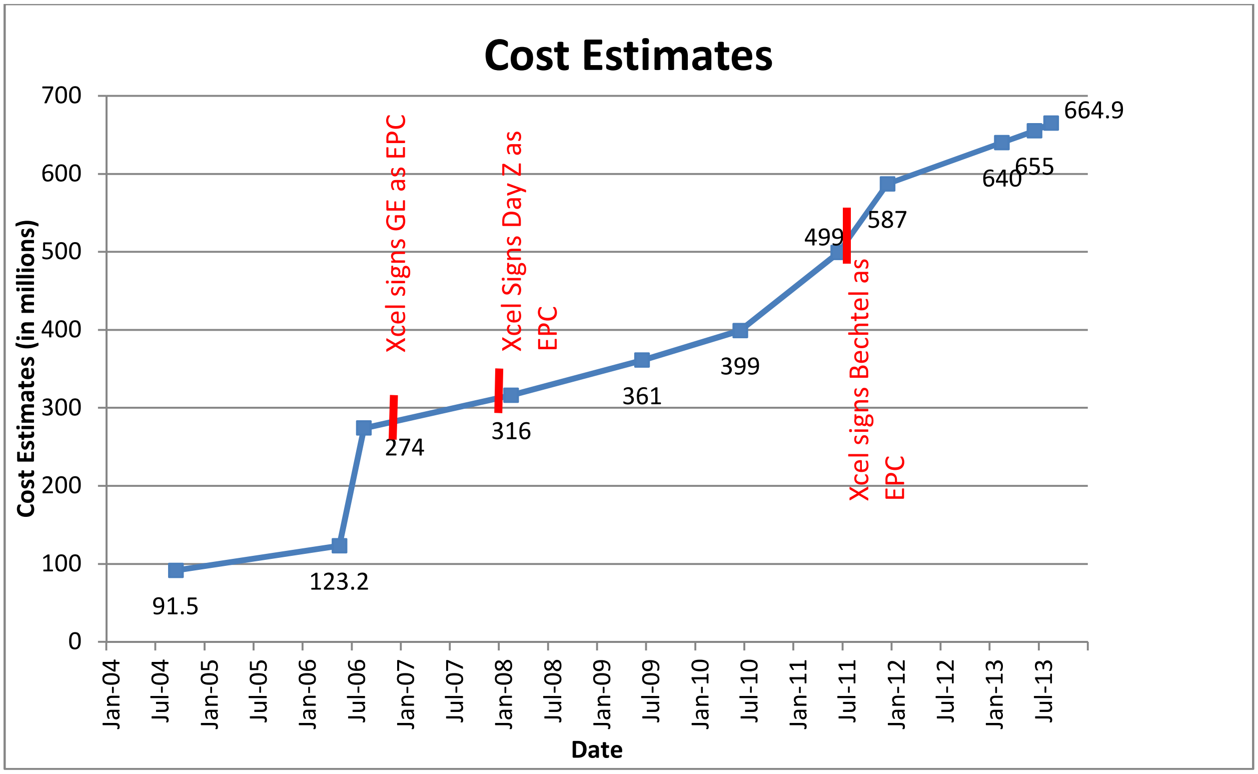
- 2004 September. The Nuclear Management Company (NMC) and Xcel produced an NMC feasibility study of a range of costs, from $60 million low to $91.5 million high to complete the EPU project based on work by General Electric (GE).
- 2006 May. NMC had GE provide an Initial Scoping Assessment with an estimate of $123.2 million.
- 2006 August. Xcel's Board of Directors approved an estimate of $274 million for combined LCM/EPU project.
- 2006 Fall. Xcel signed contracts with GE for engineering, licensing and procurement of combined LCM/EPU project.
- 2007 December. Xcel selected Day Zimmerman/Sargent & Lundy **[TRADE SECRET DATA HAS BEEN EXCISED].** to complete LCM/EPU project.
- 2008 February. Certificate of Need Application cost estimate, $316 million (adds steam dryer for $29 million).
- 2009 June. As part of the then-upcoming year's budget, the estimated cost was increased to $361 million
- 2010 June. The estimated cost was increased to $399 million (adds 13.8 kV project).
- 2011 mid-year. Xcel hired Bechtel to complete the project.
- 2011 June. The estimated cost was increased to $499 million (added $100 million for engineering, installation and some other costs).
- 2011, December. The estimated cost was increased to $587 million (increased 13.8kV and other installation costs).

- 2013 February. The estimated cost was increased to $640 million.
- 2013 June. The estimated cost was increased to $655 million.
- 2013 August. The cost was increased to the current estimate of $664.9 million.
- 2013 December. NRC EPU license received.
- 2014 Spring. Data collection problems delay power ascension.
- 2014 December. Xcel's forecast of when the Company will achieve full EPU power of 671MWe.

Q. Would you provide this information graphically?

A. Yes. Below is a graph of Xcel's LCM/EPU cost estimates over the nine years of the project. The first two estimates were for a more limited scope. Xcel's estimated $664.9 cost in August 2013 does not include the significant cost of over a year of startup testing or loss of use of the EPU during that time.

Figure 1. Increase in Monticello LCM/EPU Cost Estimates over Time



III. ANALYSIS OF LCM AND EPU DESIGN ASPECTS AND COSTS

Q. Please describe your analysis of LCM and EPU design aspects and costs.

A. The focus of this analysis was to identify projects and related costs that were needed only for LCM and those that were needed only for EPU. Some projects supported both LCM and EPU. My analysis identifies costs specifically needed to support the EPU project.

Q. What are the results of your analysis?

A. My analysis yields a result that $569.5 million (85.7 percent) of the $664.9 million total project cost was for the EPU work and $95.4 million (14.3 percent) was not required only for the EPU.

Q. Please describe the source of information you used for this analysis.

A. In his October 18, 2013 testimony Timothy J. O'Connor, includes Xcel Ex. ___ at TJO-1, Schedule 30. In this schedule, all the EPU/LCM work orders and their associated costs totaling up to the $664.9 figure are listed. I used this schedule as the source of costs for each work order in the total LCM/EPU project.

Q. How did you determine which projects were for the LCM and for the EPU?

A. In response to DOC Information Request No. 100, Xcel provided a letter submitted to the NRC on November 5, 2008. This letter requested a License Amendment to allow operation of Monticello at the higher EPU power level. This letter stated in part:

> Enclosure 8 includes a list modification planned for EPU implementation....The Enclosure 8 tables also includes modifications that are not required for EPU but have been approved as part of the ongoing life cycles management (LCM) program for [Monticello Nuclear Generation Plant] MNGP. These LCM modification are planned to be coordinated with the EPU project and are <u>planned to incorporate EPU conditions</u> (emphasis added) to maintain or improve performance margin of the respective systems.

The November 5, 2008 letter to the NRC and Enclosure 8 are provided as DOC Ex. ___ at WRJ-2. This letter was signed "under the penalty of perjury" by Mr. O'Connor. Enclosure 8, provided under oath to the NRC, clearly indicates which projects are required for the EPU and which are for the LCM.

Q. Why did you use the identification of projects to EPU or LCM presented in enclosure 8 to the November 5, 2008 NRC letter as the basis for assigning costs between EPU and LCM?

A. It is my experience and practice to use contemporaneous documentation when evaluating utility expenses or operating performance rather than subsequent analyses prepared by the utility for testimony in regulatory proceedings regarding cost recovery. A contemporaneous description of projects as EPU or LCM submitted to the NRC under oath and penalty of perjury provides the best source of the Xcel's determination of the need for each project.

Q. How did you assign the costs between LCM and EPU projects?

A. Initially I assigned the costs for the projects detailed in Mr. O'Connor's Schedule 30 to the projects identified in Enclosure 8 to the Xcel letter to the NRC discussed above. There are some project costs shown on Schedule 30 that are not included in Enclosure 8. For these I created a category called "items not explicitly mentioned in NRC Enclosure 8." Assigning the costs from Xcel Ex. ___ at TJO-1, Schedule 30 to Mr. O'Connor's classifications in NRC Enclosure 8 yields the following results:

Step 1 Table: Reconciliation of Mr. O'Connor's Schedule 30 to NRC Enclosure 8

Category	Amount ($ millions)	Percent
EPU work orders	$390.6	58.8%
Not required for EPU	$274.5	41.3%
LCM work orders	$126.7	19.1%
Items for both	$39.8	6.0%
Items not in NRC Encl. 8	$107.6	16.2%
Total	$664.9	100 %

Q. How did you assign the costs in the category "Items for both" in your table one above?

A. Since these costs, $39.8 million, were identified by Xcel as needed for both the EPU and LCM projects I did not allocate these costs to the EPU project. My approach is to only include those costs as EPU costs that were specifically identified as EPU costs in NRC Enclosure 8 described above. Thus, my analysis under-estimates the EPU-related costs.

Q. What costs were not included in Xcel's NRC Enclosure 8 filing?

A. Twelve items were not included in NRC enclosure 8 that are shown on Mr. O'Connor's schedule 30. The largest of these costs are the EPU license development cost of $59.3 million, Steam Dryer Replacement cost of $30.4 million and Expansion Joints cost of $7.0. The remaining items are of relatively low cost.

Q. How did you treat the costs that Xcel did not identify in its Enclosure 8 filing to the NRC?

A. As described in more detail below, of the costs not specifically included in NRC Enclosure 8, I included the EPU License Development of $59.3 million cost as an EPU cost as this cost is shown on Mr. O'Connor's Schedule 30 as "EPU only work – Could have been avoided in the absence of an uprate." I evaluated the Steam Dryer Replacement and concluded that this work provided sufficient benefit to long term operation that I would not include it in the EPU category.

Q. What did you do to further refine your cost assignments?

A. Using my experience and information provided during my visit to the plant on April 29, 2014, I evaluated the projects included in the "LCM work order" category. For example, prior to my site visit I had concluded that the 13.8 kV electrical distribution system upgrade should be classified as an EPU project.

Q. What basis do you have for concluding that the 13.8 KV distribution system upgrade is solely an EPU cost?

A. I conclude that, but for the EPU, this upgrade would not have been needed. That is, this modification was needed only to provide the power to the larger reactor feedwater and condensate pumps necessitated by the increased secondary side flow rates. In addition, none of the EPU projects with which I am familiar, including the similar DAEC uprate, required this type of modification. Absent the EPU requirements, this $119.5 million project cost was not necessary.

Further, this judgment was confirmed in discussions during my visit to Monticello. Specifically, Mr. O'Connor was asked if the 13.8 kV project would have been needed absent the EPU and he responded that it would not have been needed.

Q. What other information did you consider in your analysis?

A. I included in EPU costs the $59.3 million in EPU license development costs shown on Xcel Ex. ___ at Schedule 30 of TJO-1 as "EPU only work – Could have been avoided in the absence of an uprate." Making these adjustments yields the following:

Step 2 Table: Refining Cost Allocations to Reflect Cost-Causation

Category	Amount ($ millions)	Percent
EPU work orders	$569.5	85.7%
Not required for EPU	$95.4	14.3%
LCM work orders	$7.2	1.1%
Items for both	$39.8	6.0%
Items not in NRC Encl. 8	$48.3	7.3%
Total	$664.9	100 %

Q. Don't these numbers seem heavily skewed toward the EPU costs?

A. I have presented the numbers that Mr. O'Connor presented in his Schedule 30 allocated to categories in the manner that he informed the NRC of their purposes. While it is true that some of these projects also have a favorable effect on the extension of Monticello's plant life, my analysis – based on Mr. O'Connor's representations to the NRC, along with my examination of the plant and my experience with other nuclear power plants – indicates that, at best, it is uncertain how many of these projects would have actually been accomplished if not for the EPU. Moreover, the timing of such life extension projects most likely would have been significantly later, if at all.

Q. Can you point to any examples of aspects of the project that most likely would have been significantly later, if at all?

A. Yes. I learned during the site visit that replacement of the condensate demineralizers would not have been necessary absent the EPU requirements. Moreover, it is important to recognize that costs of "like-for-like" replacements are typically significantly less costly than replacements with larger components. Larger, new components often require strengthened foundations, new increased size piping, more building space, increased electrical capacity, wiring, and switchgear *(i.e.*, the $119.5 million 13.8kv electrical system). I saw numerous examples of such circumstances at the Monticello plant. For example, I learned during my visit to the plant that extensive foundation modifications requiring excavation to bedrock in some cases to install larger equipment for the increased capacity of the plant due to the EPU.

Q. What have you seen in the nuclear industry in general regarding updates to nuclear power plants?

A. The nuclear industry has shown that it is able to perform well when replacing steam generators in major construction projects, but only when the update is a "like-for-like" project. By contrast, EPU projects have tended to be over budget because of poor estimating, ignoring or not adequately exploring project complexities and failure to include an appropriate contingency in cost estimates to reflect uncertainties Xcel should have considered, as discussed in Mr. Crisp's testimony, and providing an adequate basis for such a contingency.

Unfortunately, Xcel's Monticello plant is another example where costs were not adequately scoped or estimated at the beginning of the project, resulting in poor information being presented to the Commission in Xcel's certificate of need petition for the EPU. Mr. Crisp discusses the scoping of costs while Mr. Shaw discusses information presented to the Commission.

Q. Do you agree with the methodology presented by Mr. O'Connor in his Schedules 29 and 30, Xcel Ex. ___ TJO-1?

A. No, I do not. Except for EPU license development ($59.3 million) and some minor portion of the steam dryer work ($8.4 million), Mr. O'Connor allocates a large part of the cost to the LCM project. He agrees that some portion of the LCM work was affected by the EPU and in those cases he assigns the EPU work on a pro rata basis by capacity share of the work order costs (12.1 percent for EPU). However, his approach does not adequately or reasonably reflect the costs that are due to the EPU, for all of the reasons I discuss above. As a result, Xcel's approach strikes me as inordinately biased toward minimizing EPU costs.

Mr. O'Connor, in his Direct Testimony, has expounded upon the huge, unanticipated costs associated with increased weights, flow rates, electrical loads, cooling requirements, etc. However, if any of the new equipment was even required for the LCM, these projects could have been accomplished on a "like-for-like" basis at considerably less cost. Assigning only about 22 percent of total actual project costs to the EPU is not credible or reasonable to me.

IV. IMPACTS ON DESIGN AND COST OF LCM AND EPU

Q. What did you determine to be the impact of the NRC on the design and cost of the LCM / EPU projects?

A. Both the LCM and the EPU projects must be conducted to strictly comply with NRC regulations and ensure that the licensing basis of the plant is maintained to ensure safe plant operation. As such, projects involving construction and modification of nuclear facilities are (appropriately) more highly regulated and tightly controlled to comply with safety matters than most industrial projects.

While the Monticello LCM / EPU project was underway, several significant events occurred including the Fukushima accident in Japan and the NRC's decision to review the methodology for Containment Accident Pressure analyses. While these issues clearly resulted in additional licensing costs for the EPU project, they did not result in significant additional capital costs or impact the overall project schedule.

Q. Why do you conclude that there were no effects of NRC's decisions on increased capital costs of the EPU / LCM?

A. While the initial schedule objective of completing the LCM and EPU projects during the 2011 refueling outage was delayed to resolve licensing issues, discussions with Xcel personnel during the Monticello site visit revealed that other issues, including procurement and installation of critical components, would have delayed completion until the 2013 refueling outage even without licensing delays. Discussions with Xcel personnel also revealed that there are no costs specifically related to NRC requirements regarding Fukushima impacts in the LCM/EPU project costs.

Q. What other factors affected the design and cost of the Monticello LCM and EPU projects?

A. In my opinion one of the factors that most significantly impacted the design and cost overrun of the Monticello LCM and EPU projects was Xcel's lack of understanding of the true scope of work, the amount of uncertainty and resulting inadequacy in providing a reasonably accurate estimate of the cost to implement the projects.

For example, it is possible that the 13.8 kV electric distribution system modification can be justified at the initial cost estimate of $20.9 million. However, justification at the final cost of $119.5 million is not credible. There is no reasonable basis for Xcel incurring a 5-fold increase in costs of a distribution system in the Company's own generation plant.

Xcel's lack of understanding of the scope of the LCM and EPU projects is clearly shown by comparing the original estimate of installation costs of $27.5 million to the actual installation costs of $288.6 million, an increase of more than ten times the original estimate. Installation costs for the 13.8 kV project by itself were $73.4 million more than 2.5 times the installation costs that Xcel estimated for the entire project.

Q. What other factors affected the cost of the LCM / EPU project?

A. The project management issues discussed by Mr. Crisp in his testimony clearly affected the final cost of the project. Failure to control scope growth resulted in steadily increasing cost estimates as the scope of the project grew over time. As the scope of the project grew and evolved, project management was forced to react to the changing scope.

Q. What could Xcel have done to lower the cost of the project?

A. The most successful projects proceed from engineering to procurement to construction. The approach of performing project design in parallel with procurement and construction has been problematic in EPU projects. Completion of project design leads to a known scope and allows for more accurate estimates of costs. Design completion allows for development of detailed work packages which should identify the constraints and working conditions that impact productivity. Having a reasonably developed scope of the project, with specific information about the size of the equipment on logistics of installation would have resulted in a more accurate cost estimate and a better managed project resulting ultimately in lower costs.

Q. Can you estimate the cost saving that might have been realized by a more complete design and better cost estimating?

A. It is difficult to quantify the potential cost savings that could be realized from a higher level of design completion and better cost estimating at the beginning of the project. However, the cost curve of a well-managed project does not look like the curve shown in Figure 1, where costs increase significantly over time. Ultimately, if Xcel had understood the scope and uncertainty of the project and applied a contingency factor appropriate for that level of uncertainty, they might have had a more realistic idea about the cost effectiveness of the project much earlier in the project. The issue of cost-effectiveness is discussed more in the testimony of Mr. Christopher Shaw.

Q. Does that conclude your testimony?

A. Yes, it does.

EDUCATION: Ph.D., Nuclear Engineering, Georgia Tech 1971
MS, Nuclear Engineering, Georgia Tech 1969
BS, Mechanical Engineering, Georgia Tech 1968

ENGINEERING REGISTRATION: Registered Professional Engineer

PROFESSIONAL MEMBERSHIP: American Nuclear Society

EXPERIENCE:

Dr. Jacobs has over thirty-five years of experience in a wide range of activities in the electric power generation industry. He has extensive experience in the construction, startup and operation of nuclear power plants. While at the Institute of Nuclear Power Operation (INPO), Dr. Jacobs assisted in development of INPO's outage management evaluation group. He has provided expert testimony related to nuclear plant operation and outages in Texas, Louisiana, South Carolina, Florida, Wisconsin, Indiana, Georgia and Arizona. He currently provides nuclear plant operational monitoring services for GDS clients. Dr. Jacobs was a witness in nuclear plant certification hearings in Georgia for the Plant Vogtle 3 and 4 project on behalf of the Georgia Public Service Commission and in South Carolina for the V.C. Summer 2 and 3 projects on behalf of the South Carolina Office of Regulatory Staff. His areas of expertise include evaluation of reactor technology, EPC contracting, risk management and mitigation, project cost and schedule. He is assisting the Florida Office of Public Counsel in monitoring the development of four new nuclear units in the State of Florida, Levy County Units 1 and 2 and Turkey Point Units 6 and 7. He also evaluated extended power uprates on five nuclear units for the Florida Office of Public Counsel. He has been selected by the Georgia Public Service Commission as the Independent Construction Monitor for Georgia Power Company's new AP1000 nuclear power plants, Plant Vogtle Units 3 and 4. He has assisted the Georgia Public Service Commission staff in development of energy policy issues related to supply-side resources and in evaluation of applications for certification of power generation projects and assists the staff in monitoring the construction of these projects. He has also assisted in providing regulatory oversight related to an electric utility's evaluation of responses to an RFP for a supply-side resource and subsequent negotiations with short-listed bidders. He has provided technical litigation support and expert testimony support in several complex law suits involving power generation facilities. He monitors power plant operations for GDS clients and has provided testimony on power plant operations and decommissioning in several jurisdictions. Dr. Jacobs represents a GDS client on the management committee of a large coal-fired power plant currently under construction. Dr. Jacobs has provided testimony before the Georgia Public Service Commission, the Public Utility Commission of Texas, the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Iowa State Utilities Board, the Louisiana Public Service Commission, the Florida Public Service Commission, the Indiana Regulatory Commission, the Wisconsin Public Service Commission, the Arizona Corporation Commission and the FERC.

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A list of Dr. Jacobs' testimony is available upon request.

1986-Present GDS Associates, Inc.

As Executive Consultant, Dr. Jacobs assists clients in evaluation of management and technical issues related to power plant construction, operation and design. He has evaluated and testified on combustion turbine projects in certification hearings and has assisted the Georgia PSC in monitoring the construction of the combustion turbine projects. Dr. Jacobs has evaluated nuclear plant operations and provided testimony in the areas of nuclear plant operation, construction prudence and decommissioning in nine states. He has provided litigation support in complex law suits concerning the construction of nuclear power facilities. Dr. Jacobs is the Georgia PSC's Independent Construction Monitor for the Plant Vogtle 3 and 4 nuclear project.

1985-1986 Institute of Nuclear Power Operations (INPO)

Dr. Jacobs performed evaluations of operating nuclear power plants and nuclear power plant construction projects. He developed INPO Performance Objectives and Criteria for the INPO Outage Management Department. Dr. Jacobs performed Outage Management Evaluations at the following nuclear power plants:

- Connecticut Yankee - Connecticut Yankee Atomic Power Co.
- Callaway Unit I - Union Electric Co.
- Surry Unit I - Virginia Power Co.
- Ft. Calhoun - Omaha Public Power District
- Beaver Valley Unit 1 - Duquesne Light Co.

During these outage evaluations, he provided recommendations to senior utility management on techniques to improve outage performance and outage management effectiveness.

1979-1985 Westinghouse Electric Corporation

As site manager at Philippine Nuclear Power Plant Unit No. 1, a 655 MWe PWR located in Bataan, Philippines, Dr. Jacobs was responsible for all site activities during completion phase of the project. He had overall management responsibility for startup, site engineering, and plant completion departments. He managed workforce of approximately 50 expatriates and 1700 subcontractor personnel. Dr. Jacobs provided day-to-day direction of all site activities to ensure establishment of correct work priorities, prompt resolution of technical problems and on schedule plant completion.

Prior to being site manager, Dr. Jacobs was startup manager responsible for all startup activities including test procedure preparation, test performance and review and acceptance of test results. He established the system turnover program, resulting in a timely turnover of systems for startup testing.

As startup manager at the KRSKO Nuclear Power Plant, a 632 MWE PWR near Krsko, Yugoslavia, Dr. Jacobs' duties included development and review of startup test procedures, planning and coordination of all startup test activities, evaluation of test results and customer assistance with regulatory questions. He had overall responsibility for all startup testing from Hot Functional Testing through full power operation.

1973 - 1979 NUS Corporation

As Startup and Operations and Maintenance Advisor to Korea Electric Company during startup and commercial operation of Ko-Ri Unit 1, a 595 MWE PWR near Pusan, South Korea, Dr. Jacobs advised KECO on all phases of startup testing and plant operations and maintenance through the first year of commercial operation. He assisted in establishment of administrative procedures for plant operation.

As Shift Test Director at Crystal River Unit 3, an 825 MWE PWR, Dr. Jacobs directed and performed many systems and integrated plant tests during startup of Crystal River Unit 3. He acted as data analysis engineer and shift test director during core loading, low power physics testing and power escalation program.

As Startup engineer at Kewaunee Nuclear Power Plant and Beaver Valley, Unit 1, Dr. Jacobs developed and performed preoperational tests and surveillance test procedures.

1971 - 1973 Southern Nuclear Engineering, Inc.

Dr. Jacobs performed engineering studies including analysis of the emergency core cooling system for an early PWR, analysis of pressure drop through a redesigned reactor core support structure and developed a computer model to determine tritium build up throughout the operating life of a large PWR.

SIGNIFICANT CONSULTING ASSIGNMENTS:

Georgia Public Service Commission – Selected as the Independent Construction Monitor to assist the GPSC staff in monitoring all aspects of the design, licensing and construction of Plant Vogtle Units 3 and 4, two AP1000 nuclear power plants.

Georgia Public Service Commission – Assisted the Georgia Public Service Commission Staff and provided testimony related to the evaluation of Georgia Power Company’s request for certification to construct two AP1000 nuclear power plants at the Plant Vogtle site.

South Carolina Office of Regulatory Staff – Assisted the South Carolina Office of Regulatory Staff in evaluation of South Carolina Electric and Gas' request for certification of two AP1000 nuclear power plants at the V.C. Summer site.

Florida Office of Public Counsel – Assists the Florida Office of Public Counsel in monitoring the development of four new nuclear power plants and extended power uprates on five nuclear units in Florida including providing testimony on the prudence of expenditures.

East Texas Electric Cooperative – Represented ETEC on the management committee of the Plum Point Unit 1 a 650 Mw coal-fired plant under construction in Osceola, Arkansas and represents ETEC on the management committee of the Harrison County Power Project, a 525 Mw combined cycle power plant located near Marshall, Texas.

Arizona Corporation Commission – Evaluated operation of the Palo Verde Nuclear Generating Station during the year 2005. Included evaluation of 11 outages and providing written and oral testimony before the Arizona Corporation Commission.

Citizens Utility Board of Wisconsin – Evaluated Spring 2005 outage at the Kewaunee Nuclear Power Plant and provided direct and surrebuttal testimony before the Wisconsin Public Service Commission.

Georgia Public Service Commission - Assisted the Georgia PSC staff in evaluation of Integrated Resource Plans presented by two investor owned utilities. Review included analysis of purchase power agreements, analysis of supply-side resource mix and review of a proposed green power program.

State of Hawaii, Department of Business, Economic Development and Tourism – Assisted the State of Hawaii in development and analysis of a Renewable Portfolio Standard to increase the amount of renewable energy resources developed to meet growing electricity demand. Presented the results of this work in testimony before the State of Hawaii, House of Representatives.

Georgia Public Service Commission - Assisted the Georgia PSC staff in providing oversight to the bid evaluation process concerning an electric utility's evaluation of responses to a Request for Proposals for supply-side resources. Projects evaluated include simple cycle combustion turbine projects, combined cycle combustion turbine projects and co-generation projects.

Millstone 3 Nuclear Plant Non-operating Owners – Evaluated the lengthy outage at Millstone 3 and provided analysis of outage schedule and cost on behalf of the non-operating owners of Millstone 3. Direct testimony provided an analysis of additional post-outage O&M costs that would result due to the outage. Rebuttal testimony dealt with analysis of the outage schedule.

H.C. Price Company – Evaluated project management of the Healy Clean Coal Project on behalf of the General Contractor, H.C. Price Company. The Healy Clean Coal Project is a 50 megawatt coal burning power plant funded in part by the DOE to demonstrate advanced clean coal technologies. This project involved analysis of the project schedule and evaluation of the impact of the owner's project management performance on costs incurred by our client.

Steel Dynamics, Inc. – Evaluated a lengthy outage at the D.C. Cook nuclear plant and presented testimony to the Indiana Utility Regulatory Commission in a fuel factor adjustment case Docket No. 38702-FAC40-S1.

Florida Office of Public Counsel - Evaluated lengthy outage at Crystal River Unit 3 Nuclear Plant. Submitted expert testimony to the Florida Public Service Commission in Docket No. 970261-EI.

United States Trade and Development Agency - Assisted the government of the Republic of Mauritius in development of a Request for Proposal for a 30 MW power plant to be built on a Build, Own, Operate (BOO) basis and assisted in evaluation of Bids.

Louisiana Public Service Commission Staff - Evaluated management and operation of the River Bend Nuclear Plant. Submitted expert testimony before the LPSC in Docket No. U-19904.

U.S. Department of Justice - Provided expert testimony concerning the in-service date of the Harris Nuclear Plant on behalf of the Department of Justice U.S. District Court.

City of Houston - Conducted evaluation of a lengthy NRC required shutdown of the South Texas Project Nuclear Generating Station.

Georgia Public Service Commission Staff - Evaluated and provided testimony on Georgia Power Company's application for certification of the Intercession City Combustion Turbine Project - Docket No. 4895-U.

Seminole Electric Cooperative, Inc. - Evaluated and provided testimony on nuclear decommissioning and fossil plant dismantlement costs - FERC Docket Nos. ER93-465-000, et al.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the Robins Combustion Turbine Project by Georgia Power Company - Docket No. 4311-U.

North Carolina Electric Membership Corporation - Conducted a detailed evaluation of Duke Power Company's plans and cost estimate for replacement of the Catawba Unit 1 Steam Generators.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the McIntosh Combustion Turbine Project by Georgia Power Company and Savannah Electric Power Company - Docket No. 4133-U and 4136-U.

New Jersey Rate Counsel - Review of Public Service Electric & Gas Company nuclear and fossil capital additions in PSE&G general rate case.

Corn Belt Electric Cooperative/Central Iowa Power Electric Cooperative - Directs an operational monitoring program of the Duane Arnold Energy Center (565 Mwe BWR) on behalf of the non-operating owners.

Cities of Calvert and Kosse - Evaluated and submitted testimony of outages of the River Bend Nuclear Station - PUCT Docket No. 10894.

Iowa Office of Consumer Advocate - Evaluated and submitted testimony on the estimated decommissioning costs for the Cooper Nuclear Station - IUB Docket No. RPU-92-2.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Prepared testimony related to Vogtle and Hatch plant decommissioning costs in 1991 Georgia Power rate case - Docket No. 4007-U.

City of El Paso - Testified before the Public Utility Commission of Texas regarding Palo Verde Unit 3 construction prudence - Docket No. 9945.

City of Houston - Testified before Texas Public Utility Commission regarding South Texas Project nuclear plant outages - Docket No. 9850.

NUCOR Steel Company - Evaluated and submitted testimony on outages of Carolina Power and Light nuclear power facilities - SCPSC Docket No. 90-4-E.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Assisted Georgia Public Service Commission staff and attorneys in many aspects of Georgia Power Company's 1989 rate case including nuclear operation and maintenance costs, nuclear performance incentive plan for Georgia and provided expert testimony on construction prudence of Vogtle Unit 2 and decommissioning costs of Vogtle and Hatch nuclear units - Docket No. 3840-U.

Swidler & Berlin/Niagara Mohawk - Provided technical litigation support to Swidler & Berlin in law suit concerning construction mismanagement of the Nine Mile 2 Nuclear Plant.

Long Island Lighting Company/Shea & Gould - Assisted in preparation of expert testimony on nuclear plant construction.

North Carolina Electric Membership Corporation - Prepared testimony concerning prudence of construction of Carolina Power & Light Company's Shearon Harris Station - NCUC Docket No. E-2, Sub537.

City of Austin, Texas - Prepared estimates of the final cost and schedule of the South Texas Project in support of litigation.

Tex-La Electric Cooperative/Brazos Electric Cooperative - Participated in performance of a construction and operational monitoring program for minority owners of Comanche Peak Nuclear Station.

Tex-La Electric Cooperative/Brazos Electric Cooperative/Texas Municipal Power Authority (Attorneys - Burchette & Associates, Spiegel & McDiarmid, and Fulbright & Jaworski) - Assisted GDS personnel as consulting experts and litigation managers in all aspects of the lawsuit brought by Texas Utilities against the minority owners of Comanche Peak Nuclear Station.

WITHHOLD ENCLOSURES 5 and 11 FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

November 5, 2008

L-MT-08-052
10 CFR 50.90

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Monticello Nuclear Generating Plant
Docket 50-263
Renewed Facility Operating License
License No. DPR-22

<u>License Amendment Request: Extended Power Uprate (TAC MD9990)</u>

References
1) March 31, 2008, "License Amendment Request: Extended Power Uprate" (TAC No. MD5531) ML081010193

2) June 25, 2008, "Monticello Nuclear Generating Plant (MNGP) – Withdrawal of Application for Extended Power Uprate Amendment" (TAC No. MD8398) ML081990446

3) June 26, 2008, "Monticello Nuclear Generating Plant (MNGP) – Withdrawal of Application for Extended Power Uprate Amendment" (TAC MD8398) ML081770338

Pursuant to 10 CFR 50.90, Northern States Power Company, a Minnesota corporation (NSPM), hereby requests approval of an amendment to the Monticello Nuclear Generating Plant (MNGP) Renewed Operating License (OL) and Technical Specifications (TS) as described in Enclosure 1. The proposed change would increase the maximum power level authorized by OL Section 2.C (1) from 1,775 megawatts thermal (MWt) to 2,004 MWt, an approximate thirteen percent increase in the current licensed thermal power (CLTP). This proposed request for Extended Power Uprate (EPU) represents an increase of approximately 20 percent above the Original Licensed Thermal Power (OLTP). This request also includes the supporting TS changes necessary to implement the increased power level.

By letter dated March 31, 2008 (Reference 1), Nuclear Management Company (now NSPM) submitted a request to increase the maximum power level of MNGP. By letter dated June 25, 2008, NMC withdrew this request (Reference 2). The enclosed submittal supersedes the original request.

Nuclear Regulatory Commission (NRC) approval of the requested increase in reactor thermal power level would allow NSPM to implement operational changes to generate and supply a higher steam flow to the turbine generator. Higher steam flow is accomplished by increasing the reactor power along specified control rod and core flow lines. This increase in steam flow will enable increasing the electrical output of the plant.

NSPM has evaluated the proposed changes in accordance with the requirements of 10 CFR 50.91 against the standards of 10 CFR 50.92 and has determined this request involves no significant hazards. Enclosures to this letter contain information supporting the proposed change. These enclosures are described below.

Enclosure 1 contains NSPM's evaluation of this proposed change. Included are a description of the proposed change, technical analysis of the change, regulatory safety analysis of the change (No Significant Hazards Consideration and the applicable regulatory requirements/criteria), and environmental consideration.

Enclosure 2 provides a mark-up of the Technical Specifications and the Operating License (OL) indicating the proposed changes. Additionally, NMC has transferred the OL to NSPM. References to NMC in the EPU LAR resubmittal are to be considered as references to NSPM. NSPM is the operating company for MNGP. MNGP is owned by Northern States Power Company, a Minnesota Corporation (NSPM) which is doing business in Minnesota as Xcel Energy. NSPM is used in this LAR where the subject applies to a function of the operating company. The "Company" is used where the subject applies to the plant owner (NSPM/Xcel Energy).

Enclosure 3 provides a copy of the associated draft mark-up TS Bases pages for information.

Enclosure 4 contains the MNGP Extended Power Uprate Environmental Assessment supporting a conclusion of no significant impact.

Enclosure 5 contains the power uprate safety analysis report[1] (PUSAR) formatted in accordance with RS-001, "Review Standard for Extended Power Uprates." The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the MNGP EPU and follows the guidelines contained in General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate" (CLTR). NRC has approved use of this LTR for reference as a basis for a power uprate license amendment request with the exception of the CLTR's proposed elimination of large transient testing.

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[1] The actual title of this document is Safety Analysis Report for Monticello Constant Pressure Power Uprate

Enclosure 5 contains information which is proprietary to GE Hitachi (GEH). GEH requests that this proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)4 and 9.17(a)4. An affidavit supporting this request is provided in Enclosure 6. A non-proprietary version of the PUSAR is provided as Enclosure 7.

Enclosure 8 includes a list of modifications planned for EPU implementation. The modifications listed in Enclosure 8 are planned actions which do not constitute regulatory commitments by NSPM. Modifications listed in Enclosure 8 are being implemented in accordance with the requirements of 10 CFR 50.59. The Enclosure 8 tables also include modifications that are not required for EPU but have been approved as part of the ongoing life cycle management (LCM) program for MNGP. These LCM modifications are planned to be coordinated with the EPU project and are planned to incorporate EPU conditions to maintain or improve performance margin of the respective systems.

Enclosure 9 provides the MNGP Extended Power Uprate Startup Test Plan. This enclosure specifies the EPU testing planned and provides a comparison of initial startup testing and EPU testing. Enclosure 9 includes justification for not performing the main steam isolation valve (MSIV) closure and the load rejection transient tests. Enclosure 9 supplements PUSAR Section 2.12.

Enclosure 10 provides a discussion of the analyses and testing program planned to provide assurance that unacceptable flow induced vibration issues are not experienced at MNGP due to EPU implementation.

Enclosure 11 provides the Steam Dryer Dynamic Stress Evaluation. This enclosure summarizes the analyses performed to demonstrate the structural adequacy of the MNGP steam dryer at EPU conditions. Enclosure 11 contains information which is proprietary to Continuum Dynamics Incorporated (CDI). CDI requests that this proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)4 and 9.17(a)4. An affidavit supporting this request is provided in Enclosure 12. Enclosure 13 contains the non-proprietary version of the Steam Dryer Dynamic Stress Evaluation.

Enclosure 14 is a summary of the Midwest Independent System Operator grid stability evaluation performed at the expected full EPU electrical output (2,004 MWt) that demonstrates that the EPU will not have a significant effect on the reliability or operating characteristics of MNGP or on the offsite system.

Enclosure 15 is the "Identification of Risk Implications Due to Extended Power Uprate at Monticello" and provides an assessment of the power uprate impacts on risk relative to the current probabilistic risk assessment (PRA). This Enclosure supplements PUSAR Section 2.13.

Enclosure 16 provides a table of docketed NRC acceptance review questions associated with the March 31, 2008 EPU LAR submittal. It also contains the response letters provided by NMC during the acceptance review process. Enclosure 16 is provided as a reference to assist the NRC in its review of NSPM's EPU LAR resubmittal request.

Enclosure 17 provides information to address the NRC's review concerns documented in Reference 3.

NSPM plans to implement the first phase of the extended power uprate following the spring 2009 refueling outage (RF024). Therefore, to support the NSPM schedule for the power ascension which would occur following the completion of RF024 EPU modifications (listed in Enclosure 8), NSPM requests that the proposed amendment be approved by December 1, 2009. Implementation of the first phase of the uprate is planned to be completed within 120 days from NRC approval of the EPU LAR. Phase two of the extended power uprate is planned for implementation following the completion of modifications scheduled for the refueling outage in 2011 (RF025). In accordance with 10 CFR 50.91(b), a copy of this application, with non-proprietary Enclosures is being provided to the designated Minnesota Official.

Commitment Summary

NSPM will inspect the steam dryer during the next refueling outage to confirm no unexpected changes in crack length on the steam dryer.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 5, 2008.

Timothy J. O'Connor
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company - Minnesota

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
Resident Inspector, Monticello, USNRC
Minnesota Department of Commerce w/o Enclosures 5 and 11

Enclosures (17)

Enclosure 8 to L-MT-08-052

Planned Modifications for Monticello Extended Power Uprate

ENCLOSURE 8

Planned Modifications for Monticello Extended Power Uprate

Monticello began preparation for the Extended Power Uprate (EPU) project during refueling outage (RFO) 23 in 2007 with the installation of instrumentation necessary to gather information for various evaluations required to support the EPU license amendment request. Monticello plans to install modifications in two phases to support EPU implementation. The modifications that were installed and are planned for future installation, including a summary description of the scope for each modification, are listed in the following three tables:

Table 8-1, "Pre-EPU Modifications Installed During RFO23 (2007)"
Table 8-2, "EPU Phase I Modifications Planned for 2009 (primarily RFO24)"
Table 8-3, "EPU Phase II Modifications Planned for 2011 (primarily RFO25)"

These tables also include modifications that are not required for EPU but have been approved as part of the life cycle management (LCM) program. These LCM modifications are coordinated with the EPU project and will include design criteria that incorporate EPU conditions to maintain or improve performance margin of the respective systems.

These tables are provided for information only and are not commitments. The timing and scope of the modifications may change as detailed design and outage plans progress.

ENCLOSURE 8

Table 8-1

Pre-EPU Modifications Installed During RFO23 (2007)	
Modification	**Description**
Steam Dryer Acoustic Monitoring	Installed strain gages on Main Steam Lines (MSL) for steam dryer acoustic monitoring.
Vibration Monitoring	Installed accelerometers on Main Steam (MS) and Feedwater (FW) piping for vibration monitoring.

ENCLOSURE 8

Table 8-2

EPU Phase I Modifications Planned for 2009 (primarily RFO24)	
Modification	**Description**
1AR Transformer Replacement	Replace the existing 1AR transformer due to aging concerns. This is a life cycle management (LCM) modification and is not related to EPU
Power Range Neutron Monitoring System (PRNM) (Included for completeness only. NRC approval has been requested under a separate, prior submittal.)	Replace the existing GE analog system with a GE digital system. This is an LCM modification that includes appropriate design considerations to allow implementation of EPU.
GEZIP	Replace the existing zinc injection (GEZIP) skid with a new passive injection skid. This is an LCM modification.
Piping Requalification	Revise documentation to incorporate revised pressure and temperature ratings for specific piping systems affected by EPU. Modify supports as required by the analyses. Main Steam Relief Valve (MSRV) actuator upgrades due to obsolescence issues. Reweld the Main Steam lead drain pipe connection to the Navy nipple.
HP Turbine Replacement	Replace the existing High Pressure (HP) turbine steam path with a new rotor and diaphragms to accommodate increased steam flow under EPU conditions.
LP Turbine Modifications	Replacement of several diaphragm sets and one set of buckets in each low pressure (LP) turbine to accommodate increased steam flow under EPU conditions. Replacement of selected casing bolts. Evaluate and replace the extraction steam expansion joints.
Isophase Bus Cooling	Replace the existing isophase cooling skid with a new one sized for increased EPU heat loads. Add a new redundant isophase cooling skid to increase reliability.

ENCLOSURE 8

EPU Phase I Modifications Planned for 2009 (primarily RFO24)	
Modification	**Description**
Electronic Pressure Regulator	Replace or respan the electronic pressure regulator to accommodate the increased main steam line pressure drop.
Cross Around Relief Valve (CARV) Replacement	Replace the existing CARVs and associated discharge piping to provide increased relieving capacity under EPU conditions.
Torus Attached Piping	Revise the documentation to incorporate new analyses for EPU conditions. Modify some existing supports to maintain stress limits under EPU conditions.
Main Steam Flow Transmitters	Respan or replace the main steam flow transmitters to accommodate increased flows under EPU conditions.
Feedwater Flow Transmitters and Pressure Control Instrumentation	Respan or replace the FW flow transmitters to maintain functionality with increased flow under EPU conditions. Respan or replace the existing Feedwater pressure control instrumentation to maintain functionality with increased flows and pressure drops under EPU conditions.
Feedwater Regulating Valves	Adjust the stroke of the feedwater regulating valves to provide additional range for operation at increased flow during Phase I of EPU.
Reactor Feedwater Pump Motor	Rerate the reactor feedwater pump motor to allow operation at increased flow during Phase I of EPU.
Feedwater Heater Drain and Dump Valve Replacement.	Replace the drain and dump valves on the feedwater heaters and drain coolers due to obsolescence issues. This is an LCM modification that will consider EPU conditions to enhance margin.
Inboard Main Steam Isolation Valve (MSIV) Solenoid Valve Replacement	Replace the solenoid valves on the inboard MSIVs to increase the margin between maximum containment pressure and minimum nitrogen supply pressure.
11 & 12 Drain Cooler and Feedwater Heater Rerate	Rerate the 11 and 12 drain coolers and feedwater heaters for EPU conditions.

ENCLOSURE 8

EPU Phase I Modifications Planned for 2009 (primarily RFO24)	
Modification	**Description**
Main Transformer and Isophase Duct	Replace the existing main generator step-up transformer to provide increased operating margins under EPU conditions. Remove a branch connection on the isophase bus duct to remove a hot spot and reduce overall temperatures under EPU conditions. Modify main transformer fire protection system to support the new design.
Bricks in Bioshield	Remove bricks from the bioshield to improve margin for potential missiles in the drywell.
Thermowells in Main Steam Piping	Replace or remove the thermowells in main steam piping to insure appropriate margin for flow induced vibration.
Drywell Spray Flow	Evaluate and modify the system, if necessary, to provide capability to throttle drywell spray flow consistent with design bases analytical assumptions.
EQ Modifications	Replace torus wide range water level indication transmitters
Simulator Upgrades (1)	Upgrade the simulator to include new core and containment operational response in addition to the other EPU plant modifications.
Grid Modification	Add remote reactive capability to the grid to meet the 0.95 lead/lag power factor requirements of the MISO interconnection tariff. The size and location of such devices will be identified in the Interconnection Agreement negotiated with MISO for Project G725 that adds the first phase EPU electrical output of approximately 620 MW (net).

(1) This modification will be installed prior to EPU LAR implementation

ENCLOSURE 8

Revise Setpoints [1]	Revise main steam line (MSL) high flow isolation setpoint to maintain the current setpoint in terms of % MSL flow. Revise the turbine first stage pressure setpoint to accommodate the new HP turbine and EPU inlet conditions. Revise the maximum combined flow limiter setpoint to maintain the setting at 110% of steam flow. Revise main generator protective relay setpoints to accommodate EPU conditions. Revise the rod worth minimizer low, intermediate and high power setpoints to maintain settings in terms of % rated thermal power. Revise reactor water level scram setpoint to accommodate the increased differential pressure across the steam dryer. Revise the Average Power Range Monitor (APRM) simulated power scram setpoint to maintain the setting in terms of % rated thermal power.[2] Revise the APRM neutron flux high setdown setpoint to maintain the setting in terms of % rated thermal power. [2] Revise the APRM neutron flux high scram setpoint to maintain the setting in terms of % rated thermal power. [2]

(1) This modification will be installed prior to EPU LAR implementation
(2) (Included for completeness only. NRC approval has been requested under a separate, prior submittal.)

ENCLOSURE 8

Table 8-3

EPU Phase II Modifications Planned for 2011 (primarily RFO25)	
Modification	**Description**
Reactor Feed Pump Replacement	Replace the existing reactor feedwater pumps with new pumps sized for EPU conditions. Replace the existing 4KV motors with new 13.8KV motors sized for EPU conditions. Upgrade the minimum flow piping and valves as necessary for the new pumps.
Reactor Feed Pump Discharge Check Valve Replacement	Replace the existing reactor feed pump discharge check valves due to obsolescence issues and to maintain flow margin under EPU conditions. This is an LCM modification.
Feedwater Regulating Valve Replacement	Replace the existing feedwater regulating valves with new ones sized for operation under EPU conditions.
Condensate Pump Upgrades	Replace the existing condensate pump internals with new assemblies sized for increased EPU flow rates. Replace the existing 4KV motors with a new 13.8KV motors sized for EPU operating conditions. Upgrade the minimum flow piping and valves as necessary for the new pumps. Raise hotwell water level to mitigate potential flashing and vortexing issues.
Condensate Demineralizer Replacement	Replace the existing condensate demineralizer vessels with new vessels to accommodate increased flow under EPU conditions. Replace the existing control panel with a new digital control panel.
Condensate Flow Transmitters	Respan or replace the condensate flow transmitters to accommodate increased flows under EPU conditions.

ENCLOSURE 8

EPU Phase II Modifications Planned for 2011 (primarily RFO25)	
Modification	**Description**
New 13.8KV Bus Installation	This modification is an LCM modification to increase margin in the on site distribution system. Install a new 13.8 KV bus to supply the new FW and Condensate pump motors and new 13.8 KV reactor recirculation motor-generator (M-G) set motors or adjustable speed drives pending evaluation. Replace the existing 1R and 2R transformers with new transformers, to feed two 4.8KV and two 13.8KV busses. Install new 13.8/480V transformer to feed 131 and 141 motor control centers.
Replace the Recirculation M-G Set Motors	Replace the existing recirculation M-G set motors with new 13.8KV motors or adjustable speed drives pending the results of an evaluation. This is an LCM upgrade.
Generator Rewind	Rewind the existing main generator stator and rotor to provide increased capacity required for EPU operation.
Generator Hydrogen Coolers	Replace the generator hydrogen coolers to provide additional capacity for EPU operation.
Main Exciter Replacement	Replace the existing main generator exciter with a new one to maintain operating margin under EPU conditions. This is an LCM modification.
Feedwater Heater Replacement	Replace the existing 13, 14 and 15 feedwater heaters with new ones sized for EPU conditions.
Drain Cooler Replacement/Reanalysis	Replace, re-analyze or modify the existing 11 and 12 drain coolers to maintain margin under EPU conditions.
Moisture Separator Drain Tank Cooling	Provide condensate injection into the moisture separator drain tanks discharge piping to increase sub-cooling under EPU conditions. This will stabilize flow and eliminate control issues for the drain valves.

ENCLOSURE 8

EPU Phase II Modifications Planned for 2011 (primarily RFO25)	
Modification	**Description**
Grid Modification	Add remote reactive capability to the grid to meet the 0.95 lead/lag power factor requirements of the MISO interconnection tariff. The size and location of such devices will be identified in the Interconnection Agreement negotiated with MISO for Project G929 that adds the second phase EPU electrical output of approximately 671 MW (net).

Attachment WRJ-3 Methodology for Allocation of EPU/LCM Costs

Projects divided into groups as reported to NRC in attachment B to DOC IR-100 (11/5/2008 letter to NRC.	Item number from TJO-1, Sch. 30	Projects as listed in TJO-1, Sch. 30	Costs from TJO-1, Sch. 30				
		STEP 1 ANALYSIS			STEP 2 ANALYSIS		
EPU Items					Add Item 25-$59.3, Item12-$119.5 to EPU costs		
	4	Turbine replacement	54.0				
	6	MS Flow Transmitters	0.5				
	7	Isophase Bus Cooling	5.4				
	14	Generator Field Rewind	6.7				
	15	Generator Exciter Replacement	0.1				
	18	Steam Dryer acoustic monitoring	7.3				
	19	Drywell bricks	0.1				
	20	Feedwater flow transmitters/Programmable	0.3				
	22	Main steam drain tank mods	0.0				
	26	Main Power Transformer	26.5				
	27	Condensate Impeller/Pumps/Motors	21.9				
	28	Condensate Demin System Replacement	79.8				
	29	Cross Around Relief Valves	18.4				
	31	Replacement of Feedwater Pumps/Motors	92.2				
	32	Replacement 14,15 Fw Heaters	24.8				
	34	Turbine Generator Vibration	3.5				
	36	13Fw heater replacements	49.2				
			390.7	58.8%		569.5	85.7%
LCM Items							
	2	GEZIP	2.6				
	8	EQ transmitters and detectors	0.8				
	11	Acoustic Monitoring Instumentation	0.4				
	12	13.8 kv system	119.5		Delete item 12 from LCM Costs		
	17	1AR Transformer replacement	3.4				
			126.7	19.1%		7.2	1.1%
Items for both							
	1	Power range neutron monitoring	17.5				
	5	FW heater D&DV replacement	4.7				
	13	Replacement 4 FW htr D&D valves	17.6				
			39.8	6.0%		39.8	6.0%
Items not explicitlly mentioned in IR-100							
	3	Expansion joints	7.0				
	9	Off Gas Dilution Fan Cable	0.6				
	10	Steam Dryer Replacement	30.4				
	16	Stator Water Cooler Replacement	2.4				
	21	Drywell Spray Flow Valve Repl.	0.2				
	23	Engineering and Supervision	0.0				
	24	Steam Dryer Instrumentation removal	1.2				
	25	EPU License Development	59.3		Delete Item 25 for "Items not specifically mentioned"		
	30	MS Isolation Solenoid Valve Repl.	0.3				
	33	RW Clean up Capacity Improvement	5.7				
	35	PCT Vent and Purge alves	0.4				
	37	Common costs	0.1				
			107.6	16.2%		48.3	7.3%
				100.0%			
	Total		664.8			664.8	100.0%