

**Indiana Michigan Power**  
P.O. Box 60  
Fort Wayne, IN 46801  
IndianaMichiganPower.com



*A unit of American Electric Power*

Ms. Mary Jo Kunkle  
Executive Secretary  
Michigan Public Service Commission  
6545 Mercantile way  
P. O. box 30221  
Lansing, Michigan 48909

March 31, 2010

Dear Ms. Kunkle:

Attached for filing is Indiana Michigan Power Company's (I&M) 2009 Power Supply Cost Recovery Reconciliation Case, Case No. U-15676-R, along with a proposed Notice of Hearing.

Thank you for your attention to this matter. If you have any questions or comments, please contact me.

Sincerely,

Scott M. Krawec  
Director of Regulatory Services

Attachment

**STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

**NOTICE OF HEARING  
FOR THE MICHIGAN ELECTRIC CUSTOMERS OF  
INDIANA MICHIGAN POWER COMPANY  
CASE NO. U-15676-R**

- Indiana Michigan Power Company will roll in a power supply cost recovery (PSCR) underrecovery of \$3,433,990 to its St. Joseph rate area customers and roll in a PSCR underrecovery of \$1,025,038 to its Three Rivers rate area customers as a result of its 2009 reconciliation of power supply costs and revenues, if the Michigan Public Service Commission approves its request.
- The information below describes how a person may participate in this case.
- You may call or write Indiana Michigan Power Company, 2425 Meadowbrook Road, Benton Harbor, Michigan 49023, (800) 311-6424, for a free copy of its application. Any person may review the application at the offices of Indiana Michigan Power Company.
- The first public hearing in this matter will be held:

**DATE/TIME:** May 18, 2010, at 10:00 a.m.  
This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.

**BEFORE:** Administrative Law Judge

**LOCATION:** Michigan Public Service Commission  
6545 Mercantile Way, Suite 7  
Lansing, Michigan

**PARTICIPATION:** Any interested person may attend and participate. The hearing site is accessible, including handicapped parking. Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 241-6160 in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a hearing to consider the March 31, 2010 application of Indiana Michigan Power Company (Indiana Michigan) to reconcile its 2009 power supply cost recovery (PSCR) costs and revenues for the 12-month period ended December 31, 2009. Indiana Michigan proposes to roll-in the underrecovery of \$3,433,990 including principal and interest in its St. Joseph rate area, and roll-in its underrecovery of \$1,025,038 including principal and interest in its Three Rivers rate area into its 2010 PSCR plan year costs.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets Website at: [michigan.gov/mpscedockets](http://michigan.gov/mpscedockets). Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to [mpscedockets@michigan.gov](mailto:mpscedockets@michigan.gov). If you require assistance

prior to e-filing, contact Commission staff at (517) 241-6170 or by e-mail at [mpscedockets@michigan.gov](mailto:mpscedockets@michigan.gov).

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by May 11, 2010. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon Indiana Michigan's attorney, Richard J. Aaron, Fahey Shultz Burzych Rhodes Plc, 4151 Okemos Road, Okemos, Michigan 48864.

Any person wishing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his/her wish to make a statement of position. All information submitted to the Commission in this matter will become public information: available on the Michigan Public Service Commission's Web site, and subject to disclosure.

Requests for adjournment must be made pursuant to the Commission's Rules of Practice and Procedure R 460.17315 and R 460.17335. Requests for further information on adjournment should be directed to (517) 241-6060.

A copy of Indiana Michigan's request may be reviewed on the Commission's Web site at [michigan.gov/mpscedockets](http://michigan.gov/mpscedockets), and at the office of Indiana Michigan Power Company, 2425 Meadowbrook Road, Benton Harbor, Michigan. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 241-6170.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in 1982 P.A. 304 proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Energy, Labor & Economic Growth, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1982 PA 304, as amended, MCL 460.6h et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1999 AC, R 460.17101 et seq.

**INDIANA MICHIGAN POWER COMPANY**

**2009 POWER SUPPLY COST RECOVERY  
RECONCILIATION CASE**

**MPSC CASE NO. U-15676-R**

**FILED: MARCH 31, 2010**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of )  
INDIANA MICHIGAN POWER COMPANY for )  
a Power Supply Cost Reconciliation ) Case No. U-15676-R  
proceeding for the 12-month period ) (e-file)  
ended December 31, 2009. )  
\_\_\_\_\_ )

APPLICATION

Indiana Michigan Power Company (I&M), in accordance with MCL 460.6j (Act 304), submits this Application requesting that the Michigan Public Service Commission (Commission) commence a Power Supply Cost Reconciliation proceeding for the twelve-month period ended December 31, 2009. In support of this Application, I&M respectfully represents to the Commission as follows:

1. I&M is a corporation organized and existing under the laws of the State of Indiana and is authorized to do business in the State of Michigan. I&M's principal executive offices are located in the City of Fort Wayne, Indiana. I&M has corporate power and authority, among other things, to engage in generating, transmitting, distributing, and selling electric energy within the State of Michigan and within the State of Indiana. I&M's electric system is a completely integrated and interconnected entity and is operated as a single utility.

2. I&M is a wholly-owned subsidiary of American Electric Power Company, Inc. and is an operating subsidiary in the American Electric Power System (AEP System) which is operated on an integrated interconnected basis. The operating subsidiaries of the AEP

System, including I&M, currently operate under arrangements which provide for the rendering of mutual assistance during emergencies, the effecting of maximum practical economy and dependability in day-to-day production of the electric power requirements of the AEP System and each of its operating subsidiaries, and the maximum utilization of opportunities for securing increased economies through coordination of planning, design, construction, maintenance, and operation of the AEP System and the system of each operating subsidiary, including I&M.

3. I&M's electric business in the State of Michigan is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.

4. I&M provides electric service to approximately 126,000 retail electric customers in the State of Michigan. I&M's service area is located in southwestern Michigan and northern and eastern Indiana. Pursuant to the Commission's Order in Case No. U-9912, as of March 1, 1992, I&M's service area in Michigan consists of the St. Joseph and Three Rivers rate areas.

5. By this Application, I&M requests that the Commission commence a Power Supply Cost Reconciliation proceeding to reconcile the costs of power supply incurred and recovered during 2009 for customers located in I&M's St. Joseph and Three Rivers rate areas. I&M proposes to separately reconcile the power supply costs of each rate area in this proceeding based on the Power Supply Cost Recovery (PSCR) factors in effect during 2009.

6. Section 6j(12) of Act 304 provides that not less than once a year, and not later than three months after the end of the twelve-month period covered by a utility's PSCR plan, the Commission shall commence a Power Supply Cost Reconciliation proceeding in order to reconcile the revenue recorded pursuant to a utility's PSCR factor and the allowance for cost of power supply included in the base rates established in the latest Commission Order for the utility, with the amounts actually expensed and included in the cost of power supply by the utility. In accordance with Act 304, this Application is being filed not later than three months after the end of the 2009 PSCR plan year to request that the Commission commence a Power Supply Cost Reconciliation proceeding for the twelve-month period ended December 31, 2009.

2009 PSCR Reconciliation (St. Joseph Rate Area)

7. The approved PSCR Clause applicable during 2009 to customers in I&M's St. Joseph rate area provides for the recovery, through rates, of the cost of fuel burned for electric generation, including transportation costs, reclamation costs, and disposal and reprocessing costs, together with the recovery of purchased and net interchange power costs. During 2009, pursuant to the Commission's Order in Case No. U-9656, I&M's approved PSCR Clause provided for 3.33 mills per kilowatt hour (kWh) of such costs to be recovered through base rates, with any increases or decreases from the base cost to be recovered through a PSCR factor.

8. On September 30, 2008, I&M filed an application with the Commission requesting approval of a 2009 PSCR Plan and PSCR Factor of 6.62 mills per kWh applicable to customers located in the St. Joseph Rate Area during the twelve billing months ended December 2009. On March 18, 2009, the Commission issued an Order

Approving Settlement Agreement in Case No. U-15676 which authorized a PSCR factor of up to 6.62 mills per kWh. Consistent with the Commission's Order, customers in the St. Joseph Rate Area were billed a PSCR factor of 6.62 mills per kWh during the January through December 2009 billing months.

9. I&M is requesting that the Commission approve the reconciliation of its 12-month power supply costs, revenues, and interest for 2009, and determine that the power supply costs as presented in this reconciliation filing were reasonably and prudently incurred. I&M is also requesting authorization to roll in the net actual under-recovered principal and interest amount of \$3,433,990. I&M's 2010 PSCR Plan, Case No. U-16046, filed with the Commission on September 30, 2009 included an estimate of the roll in amount and is being charged to customers during 2010.

#### 2009 PSCR Reconciliation (Three Rivers Rate Area)

10. The approved PSCR Clause applicable during 2009 to customers in I&M's Three Rivers rate area provides for the recovery, through rates, of the cost of fuel and fuel component of purchased power. During 2009, pursuant to the Commission's Orders in Case Nos. U-9205 and U-9912, the approved PSCR clause applicable to customers in I&M's Three Rivers rate area provided for 10.30 mills per kWh, including losses, of such costs to be recovered through base rates, with any increases or decreases from the base cost to be recovered through a PSCR factor.

11. On September 30, 2008, I&M filed an application with the Commission requesting approval of a 2009 PSCR Plan and PSCR Factor of 7.38 mills per kWh applicable to customers located in the Three Rivers rate area during the twelve billing months ended December 2009. On March 18, 2009, the Commission issued an Order

Approving Settlement Agreement in Case No. U-15676 which authorized a PSCR factor of up to 7.38 mills per kWh. Consistent with the Commission's Order, customers in the Three Rivers Rate Area were billed a PSCR factor of 7.38 mills per kWh during 2009.

12. I&M is requesting that the Commission approve the reconciliation of its 12-month power supply costs, revenues, and interest for 2009, and determine that the power supply costs as presented in this reconciliation filing were reasonably and prudently incurred. I&M is also requesting authorization to roll in the net actual under-recovered principal and interest amount of \$1,025,038. I&M's 2010 PSCR Plan, Case No. U-16046, filed with the Commission on September 30, 2009 included an estimate of the roll in amount and is being charged to customers during 2010.

#### I&M's Filing

13. I&M is filing its testimony and exhibits supporting the reasonableness and prudence of the actions taken which resulted in actual 2009 power supply costs and explaining the differences between the 2009 PSCR Plan, as filed, and the actual 2009 power supply costs. In addition, I&M's filing proposes interest rates, determined in accordance with Section 6j(16) of Act 304, for use in this proceeding. I&M's filing also seeks authorization of the roll in amounts for the St. Joseph and Three Rivers rate areas.

WHEREFORE, I&M respectfully requests that this Commission:

1. Accept for filing this Application, which requests that the Commission commence a Power Supply Cost Reconciliation proceeding for the twelve-month period ended December 31, 2009.

2. Upon acceptance of the filing of this Application, fix an early time and place for hearing and give notice thereof in accordance with the law and rules of practice established

by this Commission.

3. Promptly make such investigation as it may deem necessary or advisable in the circumstances.

4. Authorize I&M to roll in the actual power supply cost under-recovery from customers in its St. Joseph rate area consisting of principal and interest of \$3,433,990 and the under-recovery from customers in its Three Rivers rate area consisting of principal and interest of \$1,025,038.

5. Grant I&M such other and additional relief as the Commission may deem appropriate.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

By \_\_\_\_\_  
Scott M. Krawec  
Director of Regulatory Services

Richard J. Aaron (P-35605)  
Fahey Shultz Burzych Rhodes Plc  
4151 Okemos Road  
Okemos, Michigan 48864  
(517) 381-3209  
(517) 381-5051 (Fax)  
RAaron@fsblawyers.com

Attorneys for Indiana Michigan Power Company

VERIFICATION

STATE OF INDIANA    )  
                                  )    SS:  
COUNTY OF ALLEN    )

Scott M. Krawec being first duly sworn, deposes and says that he is the Director of Regulatory Services of Indiana Michigan Power Company, an Indiana corporation; that he is duly authorized to and has executed the foregoing Application for and on behalf of Indiana Michigan Power Company; that he has read the same and knows the contents thereof, and that the same is true to the best of his knowledge and belief.

\_\_\_\_\_  
Scott M. Krawec

Subscribed and sworn to before  
me this 31st day of March, 2010.

\_\_\_\_\_  
Regiana Maria Sistevaris  
Notary Public, State of Indiana  
County of Allen  
My Commission Expires Mar 6, 2015

DIRECT TESTIMONY OF CHARLES F. WEST  
ON BEHALF OF  
INDIANA MICHIGAN POWER COMPANY  
2009 POWER SUPPLY COST RECOVERY (PSCR) RECONCILIATION  
CASE U-15676-R

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

2 A. My name is Charles F. West. I am Manager, Fuel, Emissions and Logistics  
3 for American Electric Power Service Corporation (AEPSC), a subsidiary of  
4 American Electric Power Company, Inc. (AEP). My business address is 155  
5 West Nationwide Boulevard, Suite 500, Columbus, Ohio 43215.

6 Q. Please briefly describe your educational background.

7 A. I graduated from Queen's University in Kingston, Ontario, Canada in 1978  
8 with a degree in Mining Engineering and I later obtained my Professional  
9 Engineer license in the State of Washington.

10 Q. Please describe your professional background.

11 A. After graduation in 1978, I was employed in the mining industry by  
12 Cleveland Cliffs Iron Company in Michigan and later by Quintette Coal  
13 Company in British Columbia. I then spent over seven years employed by  
14 PacifiCorp in various engineering and management positions at coal mining  
15 operations in Washington State and Wyoming and at their headquarters in  
16 Salt Lake City, Utah. In 1995, I accepted a position as Coal Buyer for  
17 Central and Southwest Corporation (CSW), a utility holding company in  
18 Dallas, Texas. I transferred to Columbus, Ohio as a Coal Buyer after CSW's  
19 merger with AEP in 2000. In 2003 I joined Reliant Energy Inc. in  
20 Canonsburg, PA as a Senior Fuels Specialist. In 2005 I returned to AEP as

1 a Coordinator in the Fuels, Emissions and Logistics department. I was  
2 promoted to Manager of Cook Coal Terminal in Metropolis, IL in 2007 and  
3 accepted my current position in January of 2009.

4 Q. What are your principal areas of responsibility as Manager, Fuel, Emissions  
5 and Logistics for AEPSC?

6 A. I am responsible for managing coal procurement and contract oversight  
7 activities for AEP operating companies, Indiana & Michigan Power (I&M),  
8 Southwestern Electric Power Company (SWEPCO) and Public Service  
9 Company of Oklahoma (PSO).

10 Q. Have you previously provided testimony before any regulatory agencies?

11 A. Yes. I have submitted testimony to the Indiana Utility Regulatory  
12 Commission (IURC) and the Michigan Public Service Commission on behalf  
13 of I&M, the Public Utility Commission of Texas on behalf of SWEPCO and  
14 the Oklahoma Corporation Commission on behalf of PSO.

15 Q. What is the purpose of your testimony in this proceeding?

16 A. The purpose of my testimony in this proceeding is to:

- 17     ▪ Compare the forecasted 2009 delivered coal costs to actual deliveries;
- 18     ▪ Discuss I&M's coal procurement process;
- 19     ▪ Provide a summary of I&M's major coal supply agreements ; and,
- 20     ▪ Discuss the reasonableness and prudence of actions taken to minimize  
21         I&M's actual coal costs.

22 Q. Are you sponsoring any exhibits in this proceeding?

1 A. Yes, I am sponsoring Exhibit IM-1 titled "Indiana Michigan Power Company,  
2 Michigan Public Service Commission Case No. U-15676-R, 2009 Coal Price  
3 Reconciliation."

4 Q. Please summarize the comparison of actual coal deliveries and costs to  
5 those forecasted for the period January through December, 2009.

6 A. During the reconciliation period of January through December 2009 the  
7 overall weighted average delivered cost of coal for the Rockport plant from  
8 all sources was forecasted to be \$32.56/ton or 180.75 cents/MMBtu. The  
9 actual delivered cost was \$32.31/ton or 176.38 cents/MMBtu. For Tanners  
10 Creek 1-3 the overall weighted average delivered cost of coal from all  
11 sources was forecasted to be \$81.60/ton or 339.64 cents/MMBtu. TC 1-3's  
12 actual delivered cost was \$66.34/ton or 299.10 cents/MMBtu. For Tanners  
13 Creek 4 the overall weighted average delivered cost of coal from all sources  
14 was forecasted to be \$39.02/ton or 203.89 cents/MMBtu. TC 4's actual  
15 delivered cost was \$38.20/ton or 200.78 cents/MMBtu. Please also refer to  
16 Exhibit IM-1 which is a comparison of the forecasted deliveries and costs  
17 versus the actual deliveries and costs. The forecasts and actual costs  
18 provided above exclude all affiliate transportations costs.

19 Q. How did the anticipated overall cost of coal delivered to I&M plants in 2009  
20 compare to the actual cost?

21 A. The anticipated overall cost of coal delivered to I&M plants in 2009 was  
22 expected to be \$38.47 per ton or 200.14/MMBTU. I&M actual overall

1 delivered cost of coal was \$34.04 or 182.88/MMBTU (exclusive of affiliate  
2 transportation costs). This represents an 8.6 percent decrease in actual  
3 cent/MMBtu fuel cost compared to forecast.

4 Q. How were the forecasted deliveries and prices, as provided above,  
5 determined for the period from January through December 2009?

6 A. The amount of coal projected to be consumed was based on a load forecast  
7 covering the period from January through December 2009. Coal delivery  
8 requirements were then determined by taking into account coal inventory,  
9 the forecast of coal consumption, and adjustments for any contingencies  
10 that would necessitate an increase or decrease in coal inventory levels.

11 Next, the sources of the coal were determined taking into account  
12 environmental and boiler constraints, as well as contractual obligations and  
13 existing sources of supply. The price of contract coal and committed market  
14 purchases are based on contractual agreements. The prices of coal  
15 purchases not yet committed were estimated based on AEPSC's market  
16 knowledge.

17 Finally, transportation costs were forecasted based on the existing  
18 railroad transportation agreements and projected barging, railcar, and  
19 transloading rates.

20 Q. Please explain the reasons for the lower than forecasted overall delivered  
21 cost of coal at I&M Plants in 2009.

22 A. Please refer to Exhibit IM-1, which is a comparison of the forecasted coal

1 deliveries and costs for I&M versus actual coal deliveries and costs. I&M's  
2 delivered coal costs were decreased as a result of reduced consumption  
3 needs as a result of downturns in the economy, specifically with Tanners  
4 Creek 1-3 units. Overall I&M acted reasonably and prudent in the  
5 procurement and delivery of coal during 2009.

6 Q. Please describe the role of AEPSC in I&M's fuel procurement process.

7 A. AEPSC, acting as agent for all of the electric utility operating companies of  
8 the AEP System including I&M, is responsible for the procurement and  
9 delivery of coal to the Company's generating stations, as well as  
10 establishing coal inventory target levels and monitoring coal inventory.

11 AEPSC's primary objective is to assure a continuous reliable supply of  
12 coal of the appropriate quality to all of AEP's coal-fired generating stations,  
13 delivered at the lowest reasonable cost over a period of years so as to  
14 promote the generation of the lowest reasonable cost per kWh of electricity  
15 within the constraints of safety, reliability of supply, and environmental  
16 requirements.

17 Coal deliveries must be arranged so that sufficient coal is available at all  
18 times in order to provide and maintain adequate and dependable electric  
19 service for the public. The consistency and quality of the coal delivered to  
20 the generating stations is also vitally important. The consistency of the  
21 sulfur content of the delivered coal is fundamental to I&M in achieving and  
22 maintaining compliance with the applicable environmental limitations.

1 Q. Please identify and describe I&M's coal-fired generating stations.

2 A. I&M had two coal-fired generating stations that received deliveries during  
3 the period from January through December 2009. Those generating  
4 stations are Rockport and Tanners Creek.

5 The Rockport Generating Station, located in Spencer County, Indiana,  
6 consists of two 1300-megawatt coal-fired generating units. Sulfur dioxide  
7 (SO<sub>2</sub>) emissions at Rockport are limited by the New Source Performance  
8 Standard to 1.2 lbs. SO<sub>2</sub>/MMBtu. Compliance with the emission limit is  
9 achieved by using a blend consisting primarily of low-sulfur subbituminous  
10 coal in the steam generators. The coal supply for Rockport currently uses a  
11 blend of Powder River Basin coal from Wyoming and low sulfur bituminous  
12 coal from Colorado and various eastern sources.

13 The Tanners Creek generating station is located in Dearborn County,  
14 Indiana, and consists of four coal-fired units with a total nominal capacity of  
15 995 megawatts. Units 1, 2, and 3 (TC 1-3) are limited to SO<sub>2</sub> emissions of  
16 1.2 lbs. SO<sub>2</sub>/MMBtu and Unit 4 (TC 4) has been modified to use a 1.2%  
17 sulfur standard. As a result of the different air emissions standards, as well  
18 as differences in the boiler designs, the coal supplies for TC 1-3 and TC 4  
19 vary in order to meet the differing quality requirements of the units. The fuel  
20 requirements of TC 1-3 were met from bituminous sources located in  
21 Colorado and/or from eastern bituminous sources. TC 4, similar to the  
22 Rockport Station, used a blend of subbituminous and bituminous coals.

1 Q. Please provide a summary of I&M's major coal supply agreements in effect  
2 during 2009.

3 A. Rockport's need for coal during 2009 was supplied through two long-term  
4 supply agreements with COALSALES, LLC, a subsidiary of Peabody Energy  
5 in addition to supply agreements with Foundation Coal (now known as Alpha  
6 Coal Sales Co., LLC [Alpha]) and Rio Tinto Energy (now known as Cloud  
7 Peak Energy Resources, LLC [Cloud Peak]).

8 The long-term contract between I&M and the Rochelle Coal Company  
9 (now known as COALSALES, LLC) began in October 1989 and was  
10 extended by I&M and Peabody Energy Corporation with annual base  
11 tonnages scheduled through reconciliation period. A second long-term  
12 agreement with COALSALES, LLC that began in 2005, also delivered coal  
13 during the period.

14 An agreement with Foundation Coal West, Inc. (Alpha) commenced  
15 deliveries of coal to I&M during the first quarter 2008 and continued during  
16 the reconciliation period. Additionally, a new agreement with Rio Tinto  
17 Energy (Cloud Peak) commenced delivery of established tonnages to I&M  
18 during the 2009 reconciliation period. The remaining requirements were  
19 supplied by spot purchases.

20 During 2009, contract coal for TC 1-3 was supplied pursuant to I&M's  
21 two long-term agreements with Magnum Coal Sales LLC and an agreement  
22 with Argus Energy LLC. These long-term agreements had established base

1 quantities that were scheduled and delivered during the 2009 reconciliation  
2 period.

3 In addition to these long-term contracts, not committed coal was  
4 purchased to fulfill any remaining supply requirements.

5 The primary source of TC 4 coal deliveries for 2009 was the  
6 renegotiated COALSALES, LLC (Rockport) long-term contract. In addition to  
7 this contract, not committed coal was purchased to maintain sufficient coal  
8 supplies.

9 Q. Please describe I&M's coal purchasing strategy.

10 A. I&M's coal purchasing strategy is based on continuous market monitoring  
11 and evaluation along with issuing periodic competitive requests for  
12 proposals. After I&M's uncommitted needs for coal during the upcoming  
13 year are estimated, coal producers are contacted and given the parameters  
14 for the amount and quality of coal that is sought. From bid results and/or  
15 existing opportunities, if reasonable, I&M then makes its selection of the  
16 coals needed to meet its requirements based primarily on price and coal  
17 quality considerations.

18 Q. Is risk assessment an important factor in I&M's coal purchasing decisions?

19 A. Yes. The Company considers a vendor's financial status, its ability to  
20 deliver, and its past performance when evaluating its decision to do  
21 business with that supplier. Purchases from reliable vendors serve to  
22 enhance I&M's security of supply.

1 Q. Do you have an opinion regarding the reasonableness of I&M's coal costs?

2 A. Yes. I&M has and continues to aggressively pursue and manage its coal  
3 supplies and transportation costs, recognizing and addressing opportunities  
4 to provide a reliable supply of coal at the lowest cost reasonably possible.

5 Q. Does this conclude your testimony?

6 A. Yes.

**INDIANA MICHIGAN POWER COMPANY  
MICHIGAN PUBLIC SERVICE COMMISSION CASE NO. U-15676-R  
2009 COAL PRICE RECONCILIATION**

	<u>Forecast Deliveries &amp; Price</u>	<u>Actual Deliveries &amp; Price</u>	<u>Variance Actual vs. Forecast</u>	<u>% Variance</u>
<b>Rockport</b>				
Tons (000)	10,170	11,013	843	8.3%
\$/Ton FOB Mine	23.08	23.48	0.40	1.7%
Non-Affiliated Transportation	9.48	8.82	(0.66)	-7.0%
\$/Ton Delivered (PSCR)	32.56	32.31	(0.25)	-0.8%
<b>Tanners Creek 1-3</b>				
Tons (000)	1,374	474	(900)	-65.5%
\$/Ton FOB Mine	81.60	66.04	(15.56)	-19.1%
Non-Affiliated Transportation	-	0.30	0.30	0.0%
\$/Ton Delivered (PSCR)	81.60	66.34	(15.26)	-18.7%
<b>Tanners Creek 4</b>				
Tons (000)	1,471	924	(547)	-37.2%
\$/Ton FOB Mine	28.91	29.69	0.78	2.7%
Non-Affiliated Transportation	10.11	8.51	(1.60)	-15.8%
\$/Ton Delivered (PSCR)	39.02	38.20	(0.82)	-2.1%
<b>I&amp;M Total</b>				
Tons (000)	13,015	12,411	(604)	-4.6%
\$/Ton FOB Mine	29.92	25.57	(4.35)	-14.5%
Non-Affiliated Transportation	8.55	8.47	(0.08)	-0.9%
\$/Ton Delivered (PSCR)	38.47	34.04	(4.43)	-11.5%

DIRECT TESTIMONY OF MICKEY L. BELLVILLE  
ON BEHALF OF  
INDIANA MICHIGAN POWER COMPANY  
2009 PSCR RECONCILIATION CASE

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1 Q. Please state your name and business address.

2 A. My name is Mickey L. Bellville and my business address is 500 Circle Drive,  
3 Buchanan, Michigan 49107.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Indiana Michigan Power Company (I&M or Company) as the  
6 Manager of the Nuclear Engineering Department, which coordinates the  
7 supply and management of nuclear fuel and related services for the Donald C.  
8 Cook Nuclear Plant (Cook Nuclear Plant). My responsibilities include  
9 supervising activities related to the supply of nuclear fuel, including its  
10 procurement, performance, disposal, reload licensing, reactor engineering, and  
11 plant support.

12 Q. Please briefly describe your educational background.

13 A. In 1982, I graduated from the University of Michigan with a Bachelor of  
14 Science degree in Engineering. In 1999, I received a Master of Business  
15 Administration from Bethel College.

16 Q. Please briefly describe your professional background.

17 A. From May 1982 to March 1995, as an Engineer with Duke Power Company, I  
18 was involved with commercial nuclear fuel contract development, contract  
19 language interpretation, and contract negotiations. I was responsible for  
20 developing procurement strategy, economic analysis, budget preparation, and  
21 negotiation strategy and techniques.

1           From March 1995 to July 1996, I was employed as an Engineer at  
2 Consumers Power Company and was responsible for front end fuel cycle  
3 coordination, technical reload interface, economic analysis coordination,  
4 vendor interface for fuel management activities, budgetary control, cost/risk  
5 analysis, and fuel planning and scheduling.

6           From July 1996 to February 2004, while being employed by my current  
7 employer, I&M, I held responsibilities for developing a strategic partnership  
8 contract with Framatome, Inc. that included services for engineering, projects,  
9 and outage services at cost, including profit/incentives based on performance  
10 metrics. I also developed the original Nuclear Generation business continuity  
11 plan that was included in the AEP disaster recovery plan. In addition, I  
12 evaluated projects through financial analysis and capital project planning and  
13 budgeting.

14           From February 2004 to May 2004, I held Project Manager  
15 responsibilities that included project management for the Fuel Transition  
16 Project (FTP). Areas of management for the FTP included safety analyses,  
17 licensing, neutronics, Framatome interface, and budgetary controls.

18           From May 2004 to February 2007, I was the Nuclear Fuel Supervisor  
19 and my responsibilities included core reload activities, fuel procurement, cost  
20 recovery filings, vendor manufacturing oversight, regulatory administration, fuel  
21 integrity monitoring, fuel inspection coordination, and Updated Final Safety  
22 Analysis Report (UFSAR) changes.

1           Beginning in February 2007, I became the Manager of Nuclear  
2           Engineering and my responsibilities include nuclear fuel, and reactor  
3           engineering activities in support of D. C. Cook Nuclear Station.

4   Q.   Are you a member of any industrial, professional, or trade organization(s)?

5   A.   Yes. I represent I&M in both the Nuclear Energy Institute's (NEI) Utility Fuel  
6           Committee and the World Nuclear Fuel Market Organization. In addition, I  
7           have attended meetings of the Utility Nuclear Fuel Economics Group and the  
8           Electric Power Research Institute (EPRI).

9   Q.   What is the purpose of your testimony in this case?

10  A.   The purpose of my testimony in this case is to: (1) describe the relevant  
11           responsibilities of the Nuclear Engineering Department as they pertain to the  
12           2009 nuclear fuel costs, (2) describe major nuclear fuel contracts that affected  
13           I&M's 2009 nuclear fuel cycle costs, (3) discuss the reasonableness and  
14           prudence of the actions taken to minimize I&M's actual nuclear fuel costs, and  
15           (4) compare forecasted and actual 2009 nuclear fuel costs.

16  Q.   What are the responsibilities of the Nuclear Engineering Department as it  
17           relates to nuclear fuel requirements and nuclear fuel related activities?

18  A.   The responsibilities of the Nuclear Engineering Department as it relates to  
19           nuclear fuel requirements and related activities are:

- 20           • To constantly monitor and evaluate market, political,  
21           regulatory, and technical conditions that may affect the secure  
22           supply of economical and licensable nuclear fuel.

- 1           • To prepare bid specifications and evaluate bid proposals for  
2           the purchase of nuclear fuel and nuclear fuel related services,  
3           as well as the storage, shipping, and disposal of spent nuclear  
4           fuel.
- 5           • To negotiate contracts with suppliers of nuclear fuel and  
6           nuclear fuel related services.
- 7           • To establish the most economic operating parameters of each  
8           cycle with consideration of the operating requirements of the  
9           AEP System.
- 10          • To evaluate and select economic core loading plans and to  
11          administer the purchase schedule and contracts necessary to  
12          implement these plans.
- 13          • To provide support to a nuclear fuel quality assurance program  
14          for the purpose of assuring that the nuclear fuel is built  
15          according to its design criteria and specifications.
- 16          • To perform nuclear fuel economic analyses and provide  
17          current data and projections of future expenditures to other  
18          departments within AEP and I&M.
- 19          • To have core physics parameters verified to insure that the  
20          operation and performance of the nuclear fuel is within safety  
21          limits and agree with predictions.
- 22          • To ensure that the required logistics of the nuclear fuel cycle

1 takes place for each reload batch, consisting of new nuclear  
2 fuel assemblies placed in the reactor core during a refueling  
3 outage. This may include uranium mining and milling,  
4 conversion to uranium hexafluoride, enrichment, fuel  
5 fabrication, fuel assembly shipment, and reactor refueling  
6 operations.

7 Q. Please describe the major contracts entered into by I&M for supplying nuclear  
8 fuel to the Cook Nuclear Plant that affected the 2009 nuclear fuel costs.

9 A. A summary of the major contracts I&M entered into for the supply and disposal  
10 of nuclear fuel for the Cook Nuclear Plant that affected the 2009 costs follows:

11 1. Long-Term Contracts

12 a. Westinghouse Electric Company

13 Contract dated March 15, 1991

14 Fuel Fabrication – Cook Units 1 & 2

15 This contract calls for the design and fabrication of  
16 multiple reload batches of nuclear fuel for Units 1 and 2 of  
17 the Cook Nuclear Plant. The first reload batch under this  
18 contract was delivered in 1993. The contract includes  
19 fabrication of the fuel assemblies and all transportation of  
20 special nuclear material, fuel assemblies, and components  
21 incident to the fabrication process.

22 b. United States of America (Department of Energy [DOE])

1 as representative)

2 Contract dated June 13, 1983

3 Nuclear Waste Disposal

4 I&M has contracted with the DOE to take title to  
5 and dispose of the spent nuclear fuel or high-level waste.

6 I&M's fuel costs include post-April 6, 1983 spent nuclear  
7 fuel fees. Amounts associated with pre-April 7, 1983  
8 spent nuclear fuel are not part of the PSCR Reconciliation  
9 Case.

10 2. Mid-Term Contracts

- 11 a. Cameco (uranium hexafluoride)
- 12 b. Urenco (uranium hexafluoride and enrichment services)
- 13 c. United States Enrichment Corporation (enrichment  
14 services)

15 These contracts are for the procurement of  
16 materials and services on a two- to five-batch basis.

17 3. Spot Procurement Agreements and Short-Term Contracts

- 18 a. RWE NUKEM, Inc. (uranium hexafluoride)
- 19 b. UG U.S.A., Inc. (uranium hexafluoride)
- 20 c. Globe Nuclear Services and Supply (uranium  
21 hexafluoride)

22 These agreements and contracts are for the

1 procurement of materials and services for the fuel cycle on  
2 a one-time spot procurement or short-term basis.

3 Q. Can you briefly describe the long-term contract associated with Nuclear Waste  
4 Disposal?

5 A. Yes. The National Waste Policy Act of 1982 (NWP) established that the  
6 Federal government had the responsibility to provide for the permanent  
7 disposal of spent nuclear fuel (SNF). Thereafter, the DOE entered into  
8 standard contracts for the disposal of SNF and the standard contracts provided  
9 for a fee to be paid by generators and owners of the SNF. Nuclear utilities,  
10 including I&M, had no practical alternatives other than to sign standard  
11 contracts with the DOE in order to obtain and maintain operating licenses.  
12 I&M's contract with the DOE and the DOE's obligation under the contract  
13 remain in effect.

14 Q. How were I&M's post-April 6, 1983 SNF costs determined?

15 A. Post-April 6, 1983 SNF costs were calculated based on the rate of one mill  
16 per kilowatt-hour (kWh) of electricity generated and sold in accordance with  
17 the NWP. The total post 1983 SNF costs are less than one mill per kWh of  
18 projected net generation to reflect the correct definition of "generated and  
19 sold." The factor used in this calculation is based on the actual and correct  
20 formula required for calculating payments to the DOE.

21 Q. Please describe any additional obligations entered into by I&M that affected  
22 the 2009 nuclear fuel costs.

1 A. A Nuclear Fuel Lease was signed between I&M and Citicorp Leasing, Inc., with  
2 an effective date of December 14, 2007 for Batch 19 in Unit 2. Costs  
3 associated with this lease include the monthly rent component, finance  
4 charges, and administration fees. The monthly rent component for the nuclear  
5 fuel is determined by multiplying the number of BTUs consumed by the nuclear  
6 fuel during such month and the dollar amount per BTU (BTU charge) as  
7 established in an Individual Leasing Record. During months for which no  
8 BTUs are consumed, the only expenses incurred include the finance charges  
9 and administration fees. The lease term for the nuclear fuel leased is for a  
10 period not to exceed sixty (60) months.

11 Q. Why did I&M enter into this obligation?

12 A. The Nuclear Fuel Lease with Citicorp Leasing, Inc. provides a lower cost  
13 financing option versus using internal capital funds to purchase the fuel. I&M  
14 leased nuclear fuel in the past, but financial institutions suspended their offers  
15 to enter into such leases. Citicorp Leasing, Inc. offered to enter into a fuel  
16 lease, which I&M accepted.

17 Q. Does I&M lease nuclear fuel from any other financial institutions?

18 A. Yes. I&M successfully pursued a nuclear fuel lease agreement with  
19 Metropolitan Life Insurance Company / DCC Fuel, LLC (MetLife, Inc.) for Batch  
20 20 in Unit 2. This lease became effective on September 24, 2009.

21 Q. Did the Nuclear Fuel Lease with MetLife, Inc. affect the 2009 nuclear fuel  
22 costs?

1 A. Yes, the 2009 nuclear fuel costs were impacted. In particular, basic rent,  
2 financing charges and other administrative fees were applied. This is the  
3 result of Batch 20's service in 2009.

4 Q. Mr. Bellville, please discuss the actions taken by I&M that helped to minimize  
5 the 2009 nuclear fuel costs.

6 A. The actions taken by I&M that helped to minimize the cost of nuclear fuel  
7 occurred primarily as part of the long-term planning and competitive bidding  
8 processes for nuclear fuel supply to the Cook Nuclear Plant. The Cook  
9 Nuclear Plant units are refueled on an 18-month cycle and a reload batch can  
10 remain in the reactor for many years; therefore, nuclear fuel cost savings  
11 achieved through long-term planning and competitive bidding are realized over  
12 a period of years as the fuel is consumed for the production of electricity.

13 Another way the cost of nuclear fuel was minimized is through the  
14 judicious use of the secondary nuclear fuel market. Historical inventories in  
15 the nuclear fuel market have made it possible for I&M to purchase fuel on the  
16 secondary market. The logistics of providing the enriched uranium to the fuel  
17 fabricator are accomplished by an accounting transfer of material at the fuel  
18 fabricator's facility, which reduces risk for I&M.

19 Yet another example of nuclear fuel cost minimization is the  
20 examination and revision of the fuel loadings that our fuel fabricator proposes  
21 to the Company, when such revision is technically and economically justified.  
22 Technical evaluations of nuclear fuel cycle designs have also been effective in

1 improving the negotiating position of I&M during the fuel fabrication contract  
2 administration. A detailed analysis of a proposed design can show the impact  
3 of technical trade-offs made in new products offered by the bidders. I&M  
4 technical staff are involved in the vendor's reload design process so that the  
5 design process can occur during or just prior to a refueling outage. This  
6 compressed design schedule allows I&M to develop loading patterns that meet  
7 the changing energy or regulatory requirements with a minimum impact on fuel  
8 cycle economics.

9 Q. Please summarize the Cook Plant operations during 2009.

10 A. Unit 1 remained offline throughout the majority of 2009, with a return to service  
11 occurring in December 2009. This is attributable to the continuation of Unit 1's  
12 Forced Outage which began in September 2008 when the Unit 1 reactor was  
13 manually tripped due to Low Pressure Turbine vibrations. Additional testimony  
14 regarding this event has been provided by witness Jensen.

15 Consistent with the forecast, a refueling outage occurred at Cook Unit 2  
16 during the spring of 2009. Some of the additional major work performed during  
17 the refueling outage included the following: high point vent modification  
18 installation, reactor coolant pump seals replacement, solid state protection  
19 system card upgrades, eddy current testing of main feed pump condenser and  
20 low pressure heaters, valve inspections and replacements, and main generator  
21 voltage regulator replacement.

1 Q. Please summarize the comparison of actual nuclear fuel costs to those  
2 forecasted for 2009.

3 A. During 2009, the overall weighted average cost of nuclear fuel for Cook  
4 Nuclear Plant Unit 1 was forecasted to be 61.71 cents per MBtu. The actual  
5 cost was 61.73 cents per MBtu. For Cook Nuclear Plant Unit 2, the overall  
6 weighted average cost of nuclear fuel was forecasted to be 69.31 cents per  
7 MBtu. The actual cost was 69.02 cents per MBtu.

8 Q. How much uranium did I&M have in inventory in 2009?

9 A. Inventory fluctuates depending on the timing of the reload batch to be  
10 delivered. Raw material is obtained to support near-term reloads. Also, small  
11 amounts exist as a result of final detailed fuel cycle and fuel assembly design.  
12 I&M continually monitors the performance of any vendor who is under contract  
13 to assure fulfillment of contractual obligations. By contracting with reliable and  
14 proven performers and continuously monitoring their performance, the  
15 Company can operate with confidence at a lower inventory level.

16 Operating at minimum inventory and utilizing the spot market allow I&M  
17 to take advantage of the secondary market and reduce fuel-carrying costs.  
18 However, a thorough knowledge of uranium market situations is necessary to  
19 determine when conditions justify a mid-term or long-term supply contract  
20 rather than spot market purchases.

21 I&M also optimizes the scheduling of purchases to coincide with needs  
22 and contract flexibility in order to hold a minimum inventory. Any additional

1 overage material is promptly used in near-term reloads and is of minimal  
2 impact on fuel costs.

3 Q. How does I&M accomplish the goal of optimized scheduling with minimized  
4 inventory and carrying costs?

5 A. In developing contracts and making purchases, I&M carefully plans the lead  
6 time required to perform each phase of fuel processing. The target date from  
7 which decisions are made is the date the fabricated fuel is needed at the plant.  
8 Once the target date is established, it is then necessary to identify when the  
9 fabricator must have the enriched uranium. I&M continuously monitors the  
10 long term generation schedule and any changes to the generation schedule  
11 that may impact fuel procurement activities.

12 In addition, when possible, I&M negotiates payment arrangements that  
13 will occur as long after performance of the work as reasonably possible.  
14 Delaying the time that payment is required directly translates into reduced  
15 nuclear fuel costs by reducing carrying costs for a fuel reload.

16 Q. Are there other actions taken to minimize I&M's fuel cycle costs?

17 A. Yes. Because Cook Nuclear Plant is the most economical fuel cost steam  
18 plant on the AEP System, both of the Cook Nuclear Plant units are typically  
19 base-loaded. Accordingly, I&M's policy is to operate them at a steady state  
20 maximum power level unless other operational restrictions apply. Because  
21 changes in power level create additional stress on the nuclear fuel assemblies,  
22 I&M strives to have these load changes performed as a planned maneuver

1 and at proceduralized and conservative rates of change to preserve the  
2 integrity of the fuel. The fuel supply plans that have been developed result in  
3 optimum fuel performance and minimize I&M's fuel costs.

4 Along these same lines, I&M has developed an extensive capability in  
5 neutronic analysis. This allows I&M to develop for the Cook Nuclear Plant an  
6 optimized fuel management plan that considers the specific number of fuel  
7 assemblies to be loaded each cycle, what their corresponding uranium  
8 enrichment should be, which fuel assemblies should be removed from the core  
9 during the refueling, and how these new fuel assemblies and those remaining  
10 in the core should be rearranged during the refueling. As a result, I&M can  
11 meet its energy requirements while at the same time minimizing fuel cycle  
12 costs. This is a significant task, and to accomplish it, I&M has developed  
13 models of the reactor core utilizing sophisticated computer programs. These  
14 models are used to evaluate different reload arrangements proposed by fuel  
15 vendors to attain, within certain technical constraints, the goal of meeting  
16 I&M's energy requirements and minimizing fuel costs. Through this approach,  
17 I&M has been able to develop improved fuel management plans that lower fuel  
18 costs.

19 Q. Is there another area that you can point to that results in minimizing I&M's fuel  
20 costs?

21 A. Yes. The actions of the Company's technical staff to decrease the stress on  
22 the fuel during operation of the reactor are complemented by assuring that the

1 fuel assemblies are built in accordance with design requirements. I&M  
2 operates under an NRC-approved Quality Assurance Program that requires  
3 the procurement of nuclear fuel from vendors with approved Quality Assurance  
4 programs which meet federal regulations. Periodic audits and process  
5 surveillances are required for all suppliers to assure that the supplier produces  
6 a finished product that fulfills all applicable design and specification criteria.  
7 These audits examine aspects of the manufacturing process, including raw  
8 materials, details of the design and design control, machined parts, sub-  
9 assemblies, components, and the finished fuel assemblies, to assure that  
10 corresponding specifications, drawings, and design criteria are met. These  
11 Quality Assurance Programs are intended to control the design and  
12 manufacturing process to assure a product of the highest quality.

13 The fuel fabrication contract gives I&M auditors significant authority to  
14 reject material at any stage and disqualify a supplier for nonperformance,  
15 resulting in a credible threat of contract termination if audit concerns are not  
16 addressed in a timely manner. The Quality Assurance Program minimizes fuel  
17 cycle cost by eliminating design errors and manufacturing mistakes and  
18 ensuring that the final product is capable of fulfilling its intended function.

19 Q. Have the actions taken by I&M to minimize nuclear fuel costs been effective?

20 A. Yes.

21 Q. In your opinion has I&M made reasonable efforts to acquire nuclear fuel so as  
22 to provide electricity to its customers at the lowest nuclear fuel cost possible?

1 A. Yes.

2 Q. Does this complete your pre-filed direct testimony?

3 A. Yes.

DIRECT TESTIMONY OF BROCK A. ONDAYKO  
ON BEHALF OF  
INDIANA MICHIGAN POWER COMPANY  
2009 PSCR RECONCILIATION CASE

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1 Q. Please state your name and business address.

2 A. My name is Brock A. Ondayko. My business address is 155 West  
3 Nationwide Boulevard Suite 500, Columbus, Ohio 43215.

4 Q. Please indicate by whom you are employed and in what capacity.

5 A. I am the Director – RTO Operations and an employee of American Electric  
6 Power Service Corporation (AEPSC), a wholly owned subsidiary of  
7 American Electric Power Company, Inc. (AEP). AEP is the parent company  
8 of Indiana Michigan Power Company (I&M).

9 Q. Please briefly describe your educational background and business  
10 experience.

11 A. I received a Bachelor of Science – Electrical Engineering degree in  
12 November 1994, from Ohio University. My primary areas of study in  
13 Electrical Engineering were related to Power System Design and Operation,  
14 and Power System Electronics. I was employed by American Municipal  
15 Power of Ohio from 1995-1996 as an energy coordinator. I was responsible  
16 for managing the real-time energy portfolio of 88 municipalities and cities  
17 throughout the state of Ohio. My primary responsibility was to ensure an  
18 adequate amount of economic energy was procured to meet our  
19 membership load obligation. I became employed by AEPSC in 1996 as an  
20 Hourly Energy Trader and Scheduler. I progressed to the level of Manager  
21 – Hourly Trading and Scheduling in all regions in which AEP transacted in

1 1998. In 2001, I became Manager – RTO Operations, and then  
2 subsequently in 2003 was named to my current position of Director – RTO  
3 Operations.

4 Q. What are your principal areas of responsibility?

5 A. I direct activities related to AEP's commercial and operational interests in  
6 Regional Transmission Organization (RTO) markets, including the PJM RTO  
7 (PJM). In this capacity, I oversee AEP's representation and participation on  
8 numerous PJM and Midwest Independent System Operator (MISO)  
9 committees and working groups on behalf of AEP's customers and power  
10 plants. I am responsible for most communications with PJM related to  
11 market or operational issues, as well as assisting in the determination of  
12 whether AEP should participate or intervene in cases brought before the  
13 Federal Energy Regulatory Commission (FERC). In addition, I am  
14 responsible for ensuring PJM, Reliability First Corporation (RFC), MISO,  
15 Southwest Power Pool (SPP), and North American Electric Reliability  
16 Corporation (NERC) standards and procedures are understood by our  
17 operational and commercial personnel. I direct an Operational Performance  
18 & Development group whose primary function is to ensure necessary NERC  
19 and PJM Certification for our generation dispatch and production  
20 optimization personnel via in-house training and development. This group  
21 also provides employee development for our commercial and support  
22 personnel. The third group is Business Process Improvement. This group

1 manages and provides technical expertise for the integration of new  
2 generation resources into AEP operational systems associated with the  
3 PJM, SPP, and ERCOT regions.

4 Q. Have you previously filed testimony before any regulatory commissions?

5 A. Yes. I have filed testimony before the Michigan Public Service Commission,  
6 regarding PJM expenses, in I&M Power Supply Cost Recovery  
7 Reconciliation Case Nos. U-15416-R, U-14704-R and U-15004-R, and  
8 before the Indiana Utility Regulatory Commission (IURC) regarding PJM  
9 expenses, in general rate case Cause No. 43306.

10 Q. What is the purpose of your testimony in this proceeding?

11 A. The purpose of my testimony in this proceeding is to provide an overview of  
12 AEP's costs and revenues from operating in PJM and the effect, if any, that  
13 AEP's participation in PJM had on purchases from third parties during the  
14 Reconciliation Period.

15 Q. What is PJM?

16 A. The PJM Interconnection, LLC (PJM) is a FERC-approved regional  
17 transmission organization (RTO) joined by AEP to fulfill its regulatory  
18 obligation to join an RTO. PJM is a long established organization that  
19 manages the transmission grid for numerous companies in the eastern  
20 United States and fulfills the functions defined in *FERC Order 2000*<sup>1</sup>. It

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<sup>1</sup> FERC Order 2000 calls for, but does not require, companies owning transmission systems to place the grid under the control of RTOs, which will have sole responsibility for operation and expansion of the transmission system, maintaining short-term reliability while establishing and managing tariffs, and responding to requests for service.

1 operates the largest centrally dispatched electric grid in the U.S.

2 Q. When did AEP's integration into PJM occur?

3 A. The AEP System East Zone integrated its operations with PJM and began  
4 participating in the PJM energy market on October 1, 2004.

5 Q Please describe what you refer to as the AEP System East Zone.

6 A. In addition to I&M, the AEP generating affiliates comprising the AEP  
7 System–East Zone consist of:

- 8 • Columbus Southern Power Company, serving portions of central and  
9 southern Ohio;
- 10 • Appalachian Power Company, serving portions of West Virginia and  
11 Virginia;
- 12 • Kentucky Power Company, serving portions of eastern Kentucky; and
- 13 • Ohio Power Company (OPCo), serving portions of Ohio.

14 In addition, two Operating Companies in the AEP System–East Zone,  
15 Kingsport Power Company and Wheeling Power Company represent non-  
16 generating affiliates.

17 Q. Please describe the AEP System-East Zone participation within PJM.

18 A. AEP participates within the PJM RTO as a load serving entity (LSE), a  
19 capacity resource provider (generation owner) and as a transmission owner.

20 As an LSE, AEP has an obligation under the Reliability Assurance  
21 Agreement to ensure adequate capacity resources are available to meet the  
22 reliability requirements established by PJM. As a capacity resource provider  
23 (generation owner), AEP must make its generation resources available to

1 PJM and to follow PJM's dispatch instructions.

2 Finally, as a transmission owner, AEP operates and maintains its  
3 transmission facilities in a coordinated manner with the PJM RTO. In  
4 addition, the AEP System East Zone, together with the systems of other  
5 members of PJM, is planned on an integrated basis via PJM's Regional  
6 Transmission Expansion Plan process. However, AEP continues to plan  
7 transmission expansions for service reliability for the AEP footprint. The  
8 expansion of the transmission system for the entire PJM footprint is done in  
9 a coordinated manner while continuing to provide the reliable transmission  
10 system to supply I&M's customers in Michigan.

11 Q. Has AEP's integration into PJM changed the AEP East System  
12 Interconnection Agreement (Interconnection Agreement)?

13 A. No. The FERC-approved Interconnection Agreement provides the basis for  
14 financial settlement among the member companies. In brief, the lowest  
15 energy cost resources (AEP generation and third-party purchases) are still  
16 assigned to internal load. Purchases are made from PJM or other third  
17 parties when it is economic to do so and off-system sales continue from  
18 resources that are not needed to meet internal load requirements. In  
19 addition, other PJM-related costs and revenues are assigned on a member  
20 load ratio (MLR) basis.

21 Q. Describe the PJM-related costs and revenues?

22 A. The costs and revenues include congestion costs, financial transmission

1 right (FTR) revenues, operating reserves and some ancillary services  
2 (including synchronous condensing, reactive supply, black start, and  
3 regulation service), collectively referred to as the "PJM Costs and  
4 Revenues". These PJM Costs and Revenues are associated with serving  
5 I&M retail customers.

6 Q. Please describe the concept of congestion costs in PJM.

7 A. Congestion costs in PJM are simply the difference between what a load  
8 pays for energy and what a generator supplying the load receives for the  
9 energy it produces. If there were no congestion on any transmission line in  
10 PJM, the Locational Marginal Price (LMP) would be the same for all  
11 generators and loads across the entire PJM market region. However, when  
12 transmission lines become constrained, LMPs vary across the entire region  
13 and the price for energy paid by the load is different than the price received  
14 for energy produced by the generator.

15 Q. Are there different kinds of congestion?

16 A. Yes. PJM congestion costs are made up of both explicit and implicit  
17 congestion.

18 Q. Please explain PJM explicit congestion costs.

19 A. Explicit congestion measures the difference in Locational Marginal Pricing  
20 (LMPs) between two specific points on the power system. This type of  
21 congestion applies when a Market Participant schedules a transaction  
22 between two distinct points.

1 Q. Please explain PJM implicit congestion.

2 A. Implicit congestion is a measure of congestion costs between a portfolio of  
3 generation resources and the loads they serve which include off-system  
4 sales. Implicit congestion is the difference between 1) the price paid to PJM  
5 by the Load Serving Entities (LSEs) in serving their load and 2) the price  
6 paid by PJM to the generators which are used as energy resources to serve  
7 the load. The price paid by the LSEs is the load-weighted average LMP  
8 price for all the nodes in the LSEs territory. The price paid to the generators  
9 is the energy-weighted average for all the generation nodes used to serve  
10 the LSEs territory.

11 Q. Please explain the concept of FTRs in PJM.

12 A. PJM developed the concept of FTRs to help transmission customers offset  
13 the incremental costs associated with congestion. FTRs are designed to  
14 protect LSEs from the uncertainty associated with congestion charges.  
15 FTRs are financial contracts that entitle the holder to a stream of revenues  
16 or charges based on the congestion cost across a transmission path  
17 between the FTR source and the FTR sink. LSEs can hedge the congestion  
18 cost risk across a transmission path by choosing FTRs that offset the  
19 congestion charges. During each PJM planning year (June through the  
20 following May), AEP is allocated an amount of Auction Revenue Rights  
21 (ARRs) that are equivalent to the AEP load that occurs at the time of the  
22 PJM RTO peak hour. AEP must then decide whether it intends to keep the

1 proceeds made by offering the ARR's into the PJM annual auction or convert  
2 the ARR's to FTR's. AEP typically elects to convert the ARR's to FTR's to  
3 hedge congestion risk, as was the case in 2009. AEP must then choose the  
4 best combination of FTR's to manage the financial congestion risk for  
5 serving the AEP load. Once the awards are made by PJM, AEP is not  
6 allowed to change the FTR selections until the beginning of the next  
7 planning year (June).

8 Q. Please describe operating reserve charges.

9 A. Operating reserve charges in PJM provide for make-whole payments to  
10 generators that are called on by PJM but which do not receive sufficient  
11 revenue from the energy or ancillary service markets to cover their offers.  
12 PJM may call on these units either day-ahead or in real-time.

13 For example, after the daily bids are cleared at 1600 Eastern  
14 Prevailing Time, PJM may determine that additional generation should be  
15 brought on line for the next day for reliability purposes. Examples of issues  
16 impacting reliability could be changes in weather, generation forced  
17 outages, or projected transmission facility overloads. PJM will call on these  
18 units and pay them for their start-up costs as well as their operating costs  
19 throughout the time they are requested to run by PJM. The costs incurred  
20 for these expenses are called operating reserves. According to the PJM  
21 Operating Agreement, the owner of generation which is scheduled by PJM  
22 under these conditions should be financially made whole equivalent to the

1 amount of payment required to operate the resource. This information is  
2 embedded within their day-ahead market-based offer. If PJM calls upon the  
3 unit to operate for congestion control, voltage control, or other reliability  
4 requirements and there are no other resources that can mitigate the  
5 problem, the unit will be made whole to its approved day-ahead cost-based  
6 offer.

7 Q. Are PJM Operating Reserves the same as the RFC operating reserves?

8 A. No. The RFC is a newly formed reliability organization replacing the East  
9 Central Area Reliability Council (ECAR, of which AEP was a member), Mid-  
10 Atlantic Area Council (MAAC), and Mid-America Interconnected Network  
11 (MAIN) organizations beginning in January 1, 2006.

12 Q. Please explain the difference between RFC operating reserves and the PJM  
13 operating reserves?

14 A. The RFC operating reserves are the minimum amount of unloaded,  
15 available generation and regulation service that a balancing authority must  
16 have available to reliably serve load on a daily basis. PJM abides by RFC  
17 minimum requirements and may even chose to operate at higher reserve  
18 levels, as warranted. In keeping with the focus on reliability, RFC operating  
19 reserve requirements for the RFC portion of the PJM footprint are based on  
20 two types of reserves. One is primary reserves, which are reserves which  
21 must be able to be online within 10 minutes and must equal at least 150% of  
22 the largest unit. The second type is synchronized reserves, which is the

1 amount of reserve that must be available and spinning in real-time  
2 operations and must at least equal the most severe single contingency,  
3 which is usually the largest single unit on the system. Although PJM has a  
4 market for the procurement of regulation service, if the market clearing price  
5 for regulation service does not cover the full-cost of procuring the regulation  
6 service, PJM may include this incremental cost in the billing line-item called  
7 operating reserves.

8 Q. Can you please describe the Day-Ahead Scheduling Reserve market?

9 A. As approved by FERC, beginning June 1, 2008, PJM implemented a market  
10 for Day-ahead Scheduling Reserves. The product establishes a price for  
11 supplemental day-ahead reserves, which PJM needs to acquire to satisfy  
12 reliability standards. All load-serving entities are required to carry a  
13 percentage of their daily peak load projection as day-ahead scheduling  
14 reserves. The supplemental supply sources can come from any resource  
15 which can be online and produce energy within a 30-minute timeframe.

16 Q. Please explain PJM ancillary services and the need for them.

17 A. I&M incurs PJM Costs and Revenues for net synchronous condensing, net  
18 reactive supply, net black start services, and net regulation services.  
19 Ancillary services are necessary to support the transmission of capacity and  
20 energy from generating resources to loads, while maintaining reliable  
21 operation of the transmission system.

22 Q. Please explain synchronous condensing service.

1 A. Synchronous condensing is an ancillary service charge that is incurred when  
2 PJM must pay for a unit to spin its turbine without the actual production of  
3 energy. This can occur when PJM needs a combustion turbine to be  
4 available to come on line instantaneously for spinning reserves, system  
5 reliability, reactive power, or even economic energy.

6 Q. Please explain reactive supply service.

7 A. All transmission customers, including those that use network service to  
8 serve internal load, must purchase reactive supply service from PJM.  
9 Reactive supply service is required to maintain transmission voltages within  
10 acceptable PJM reliability limits. These FERC-approved, cost-based  
11 charges are based on annual revenue requirements filed by generating units  
12 that can provide reactive power.

13 Q. Please explain black start service.

14 A. All transmission customers must purchase black start service from PJM.  
15 Black start service is required to ensure that the power grid can restart  
16 following a complete system blackout. The critical units needed for system  
17 restoration are compensated for the costs incurred in maintaining black start  
18 service capability. These cost-based charges are derived from annual  
19 revenue requirements that are submitted by the generators providing the  
20 service and are approved by both the FERC and the PJM Independent  
21 Market Monitoring Unit – Monitoring Analytics.

22 Q. Please explain regulation service.

1 A. All PJM loads must secure regulation service. Regulation service allows  
2 PJM to correct continuous, short-term fluctuations in electricity usage and  
3 output that might affect the stability of the power system. Regulation service  
4 allows for the continuous balancing of resources (generation and  
5 interchange) with load and for maintaining scheduled frequency at sixty  
6 cycles per second (60 Hz).

7 Q. Has membership in PJM affected the dispatch of AEP's, and specifically  
8 I&M's generating units?

9 A. Not significantly. Even though PJM now provides dispatch instructions for  
10 AEP's (including I&M's) generation resources, I&M customers continue to  
11 receive the benefit of being provided service via I&M generation resources  
12 and the Interconnection Agreement.

13 Q. In your opinion, were the costs of operating in the PJM RTO during the 2009  
14 reconciliation period reasonably and prudently incurred?

15 A. Yes.

16 Q. Does this conclude your direct testimony?

17 A. Yes it does.

TESTIMONY OF JOSEPH N. JENSEN  
ON BEHALF OF  
INDIANA MICHIGAN POWER COMPANY  
2009 PSCR Reconciliation Case

1 Q. Please state your full name and business address.

2 A. My name is Joseph N. Jensen. My business address is One Cook Place,  
3 Bridgman, Michigan, 49106.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the American Electric Power Service Corporation (AEPSC) as  
6 Senior Vice President and Chief Nuclear Officer. I am also a Vice President of  
7 the Indiana Michigan Power Company (I&M or Company). AEPSC provides  
8 engineering, financing, accounting, and similar planning and advisory services to  
9 the subsidiaries of the American Electric Power (AEP) System, one of which is  
10 I&M.

11 In that position, I was responsible for supervising the safe and effective  
12 management of the outage that occurred at Unit 1 of the Cook Nuclear Plant  
13 (Cook Plant) in 2009 (Unit 1 turbine outage).

14 Q. Please briefly describe your educational and business experience.

15 A. I hold a Bachelor of Science Degree in business management as well as a human  
16 resources management certification from Cardinal Stritch University. I am also a  
17 graduate of the U.S. Navy Nuclear Power Schools. I completed the Executive  
18 Development Program at the University of Minnesota Carlson School of  
19 Management.

20 I joined I&M in October 2003. Prior to joining I&M I was the Plant Manager

1 at Point Beach Nuclear Station working for Nuclear Management Company  
2 (NMC). Prior to my assignment at Point Beach I worked for NMC (and other  
3 owner/operators) at Prairie Island for 16 years as the training manager, work  
4 control manager, engineering director and manager of high level waste. I  
5 received a senior reactor operator's license certification while at Prairie Island.

6 I became the Chief Nuclear Officer at the Cook Nuclear Plant in 2009. I  
7 held the positions of Vice President - Site Support Services and Site Vice  
8 President at the Cook Nuclear Plant before accepting my current role.

9 Q. Have you previously testified before any regulatory commissions?

10 A. Yes. I have testified on several occasions in other jurisdictions. Primarily, I have  
11 testified in proceedings before the Minnesota Public Utilities Commission related  
12 to obtaining a Certificate of Need for Major Nuclear Projects. I also testified  
13 before the Indiana Utility Regulatory Commission in Cause No. 38702-FAC-62

14 Q. Are you sponsoring any exhibits to your testimony?

15 A. Yes. I am sponsoring Exhibits IM-2 through IM-4. Exhibit IM-2 is a diagram of  
16 the Cook Plant Unit 1 turbine generator shaft line, Exhibit IM-3 is a picture of  
17 damaged L-0 blades on the low-pressure (LP) turbine, and Exhibit IM-4 is a copy  
18 of the Root Cause Analysis conducted by I&M.

19 Q. What is the purpose of your testimony in this proceeding?

20 A. The purpose of my testimony is to describe the reasons that Unit 1 was out of  
21 service from September 20, 2008 to December 19, 2009 and explain why this

1 outage was not caused or prolonged by any imprudence or mismanagement by  
2 I&M. In particular, I will describe the events that required plant operators to take  
3 the unit off line and the safe and effective recovery from this incident.

4 Q. What did you do to prepare to testify for this proceeding?

5 A. In preparation for testifying in this proceeding I went through a detailed review of  
6 the outage with the Cook project team. I have overall responsibility for all aspects  
7 of operations at the Cook Plant including nuclear safety and for recovery from the  
8 events described below.

9 Q. What caused Unit 1 to be removed from service on September 20, 2008?

10 A. On September 20, 2008, at approximately 8:05 PM, operators shut down Unit 1  
11 due to high vibrations in the main turbine. The rotating parts of the main turbines  
12 include three LP turbine rotors which are connected to one high pressure (HP)  
13 turbine rotor and the electric main unit generator, as shown in Exhibit IM-2.  
14 Overall, these rotating parts comprise approximately 225 feet in length and weigh  
15 approximately 860 tons. These precision parts spin at 1,800 revolutions per  
16 minute and produce significant forces when operating normally, with  
17 displacements (vibrations) measured in thousandths of an inch. The turbine  
18 equipment is part of the non-nuclear secondary plant located in the turbine  
19 building, and is separate and isolated from the primary plant that includes the  
20 nuclear reactor. The secondary plant is similar to steam power generation  
21 systems in place at other generating plants, regardless of whether they are

1 nuclear or fossil-fired.

2 Q. How did the plant operators respond to the high vibrations?

3 A. The Unit 1 operators immediately responded to the event exactly as they were  
4 trained. Within one second, there were numerous separate alarms indicating  
5 very high vibrations in the turbine building. The reactor operator manually shut  
6 down the reactor within five seconds. Immediately following the reactor shut  
7 down, the main turbine generator shut down as designed and the operators  
8 properly took action to stop the spinning of the turbine rotor. Plant protection  
9 workers immediately responded to contain and extinguish a small fire in the  
10 electric generator. Other personnel responded as trained to ensure the safety of  
11 the plant and the community. In addition, notice of the incident was promptly  
12 provided to regulators and to the community to assure them that there was no  
13 danger.

14 Q. Were there any injuries or equipment damage associated with this event?

15 A. Despite the significant nature of the event, there were no injuries caused directly  
16 by the turbine vibration or the small fire that ensued. Importantly, the community  
17 surrounding the plant was never in danger. However, the enormous forces  
18 generated from the LP turbine failure resulted in significant damage to the  
19 components on the turbine generator shaft line, the shaft bearings, and  
20 associated equipment in the turbine building.

21 Q. What did I&M do once the actual incident ceased and the safe shut down of the

1 unit was complete?

2 A. It was immediately expected that the substantial damage incurred to the steam  
3 side of the plant would require significant time to repair. Accordingly, I&M  
4 promptly took action to recover from the incident. The timeline of the recovery  
5 events can be briefly summarized in three phases: Immediate Recovery,  
6 Assessment, and Long Term Recovery.

7 The Immediate Recovery phase included the safe shutdown of Unit 1 and  
8 the cleaning of pipe insulation and oil to prevent potential industrial safety hazards  
9 and assure reliable operation of equipment that was coated with oil from the  
10 event. These cleanup efforts continued throughout the recovery. During the  
11 Assessment phase, the I&M team evaluated the cause of the event and the  
12 actions necessary to return the unit to reliable service in a safe, efficient and  
13 timely manner. The Long Term Recovery phase began with the engineered  
14 removal, inspection, and evaluation of damaged equipment. This phase included  
15 the discovery of significant additional damage as major plant components were  
16 inspected and disassembled. It also included the repair of existing parts,  
17 equipment, and structures, and the replacement of parts where repair was not  
18 feasible. Each phase of the recovery had significant overlap with the other  
19 phases and all phases have now been completed.

20 Q. Who was the vendor of the Unit 1 turbine equipment?

21 A. I&M contracted with Siemens Power Generation, Inc. (Siemens) to replace the

1 three LP turbine rotors with upgraded state of the art models to improve quality,  
2 reliability, availability and efficiency.

3 Q. Was the replacement of the three LP turbines competitively bid?

4 A. Yes. The Cook Plant Business Services Department and the LP turbine rotor  
5 replacement project team followed the applicable I&M procedures to obtain bids,  
6 evaluate the bids and select the LP turbine supplier. The procurement process  
7 used to acquire the LP turbine replacement rotors was carried out in accordance  
8 with the policies and procedures documented in the I&M Nuclear Generation  
9 Group (NGG) procedures for Contract Development, Execution, and  
10 Administration and Procurement and Use of Outside Services.

11 Q. What ultimately lead to the selection of Siemens as the vendor for the turbine  
12 replacements?

13 A. Prior to receipt of the proposals, detailed evaluation criteria were established in  
14 order to arrive at overall bidder scores. Three vendors submitted bids. The  
15 overall bid evaluation resulted in the selection of Siemens for the replacement of  
16 the LP turbines. Siemens is a world class engineering firm that has decades of  
17 experience in designing and manufacturing large scale steam power system  
18 equipment, including turbines. The existing three LP turbines were replaced with  
19 the new rotors designed and manufactured by Siemens in the fall of 2006.

20 Q. Did I&M perform any due diligence investigation to ensure that it was receiving a  
21 quality product from Siemens?

1 A. Yes. The LP turbine project manager and the Cook Plant Business Services  
2 contract administrator provided oversight of the engineering, design,  
3 manufacturing, assembly, test and transportation requirements that were  
4 required to support the scheduled Unit 1 – 2006 LP turbine replacement outage.  
5 I&M engaged the engineering firm Sargent & Lundy (S&L) to develop the  
6 engineering interface and requirements documents and the modification package  
7 for the Cook Plant with the new Siemens turbines. The monitoring effort of  
8 Siemens by I&M included the following key actions:

- 9
- 10 • monitoring monthly progress reports and schedules from Siemens;
  - 11 • frequent interface with Siemens throughout the design, manufacturing,  
12 assembly and transportation phases;
  - 13 • oversight of key inspection points
- 14

15 I&M's review of Siemens engineering, design, manufacturing, assembly and  
16 testing did not reveal any deficiencies in the new LP turbine rotors.

17 Q. Was it necessary to make any modifications to the LP turbine blades after they  
18 were delivered to the Cook Plant?

19 A. Yes. After the new rotors were delivered to the plant in August 2006 Siemens  
20 notified I&M that it had found a turbine system issue, which Siemens addressed  
21 by welding tuning weights on the tips of the L-0 blades. I&M provided oversight  
22 and contracted with third party experts to review Siemens' work.

23 Q. Was Siemens responsible for the installation of the replacement turbines at the  
24 Cook Nuclear Plant?

1 A. Yes. Siemens was responsible for the installation of the turbines, with  
2 participation from I&M to make sure that the installation conformed to I&M's  
3 requirements, practices and procedures prior to going into service.

4 Q. Did anything abnormal happen during installation of the turbine rotors that may  
5 have caused damage to the turbine blades?

6 A. No. Nothing abnormal occurred during the installation of the turbine rotors that  
7 may have caused damage to the turbine blades. After the turbines were  
8 installed, they were also inspected and tested in order to determine that the  
9 equipment was ready to be placed in service. During this time the turbines did  
10 not indicate that there were any problems that arose as a result of the installation  
11 process.

12 Q. Were the replacement turbines ever inspected after being placed in service and  
13 prior to failure in September 2008?

14 A. Yes. The rotors and all 300 L-0 blades were visually inspected by Siemens  
15 personnel during the next refueling outage in the spring of 2008 with acceptable  
16 results, and the L-0 blade tips on the LP-B rotor were inspected using non-  
17 destructive testing techniques with acceptable results.

18 Q. Was there any operating condition prior to the failure of the turbine that indicated  
19 any problems with the equipment in question?

20 A. No. Cook Unit 1 and the turbine were operating normally. There was no prior  
21 indication of anything abnormal. The turbine shaft is equipped with full time

1 vibration monitoring equipment which provides plant operators with indication and  
2 alarms in the control room. The turbine vibration was within accepted values prior  
3 to the event. The unit was properly operated within all established operational  
4 limits.

5 Q. What caused the vibration in the turbine and the resulting event?

6 A. Based on evaluation of the damaged equipment, the vibration and resulting event  
7 were initiated by the failure of two blades on one of the new LP turbine rotors, and  
8 one blade on another new LP turbine rotor. Specifically, the turbine blades that  
9 failed were from the largest row of blades, referred to as the L-0 blades (See  
10 Exhibit IM-3 – photograph of damaged L-0 blades).

11 Q. Are turbine rotor blade failures common?

12 A. No, but turbine rotor blade failures do happen despite the best efforts of world  
13 class engineers, technicians, and craftsmen. Turbine rotors installed in large-  
14 scale high energy applications have failed from time to time in both nuclear and  
15 non-nuclear electrical generating applications.

16 Q. Did I&M perform an analysis to determine the root cause of the turbine failure?

17 A. Yes. I&M organized a team and retained outside experts to determine the root  
18 cause of the turbine failure. The teams conducted an extensive and critical  
19 review of all possible causes and spent approximately six months evaluating  
20 records and examining equipment. It was an exhaustive and rigorous process  
21 that was required not just to determine the cause of this event, but to ensure that

1 a similar event would not occur elsewhere.

2 Q. What was the root cause of the turbine failure?

3 A. The Root Cause Evaluation performed by I&M and its independent third party  
4 consultants determined that the Root Cause was a blade-rotor system design  
5 which failed to provide adequate stress margin in at least three L-0 blades. This  
6 deficiency caused the three L-0 blades to occasionally exceed their stress limit at  
7 the highest stress location thereby suffering high cycle fatigue. Eventually the  
8 fatigue caused the blades to crack at their base and to come loose from the rotor,  
9 causing the damage. The tuning weights that were welded to the L-0 blades did  
10 not contribute to the event.

11 Q. Did the Root Cause team critically investigate whether I&M actions caused the  
12 event?

13 A. Yes. The Root Cause Evaluation found no indication of imprudence or  
14 negligence on the part of I&M related to the turbine failure. (See Exhibit IM-4,  
15 Root Cause Report). While there are lessons that I&M has learned from the  
16 event, it is my opinion that the outage was not caused or prolonged by any  
17 imprudence or mismanagement by I&M.

18 Q. Were any of the failed turbine parts under vendor warranty?

19 A. Yes. The contract with Siemens to purchase and install the LP turbine rotors  
20 included provisions that warranted the Major Equipment (which included the  
21 turbine rotors and blades) against defects in materials and workmanship for ten

1 years. The new LP turbine rotors had only been in service for two years when  
2 they failed. Per the warranty provisions, the vendor was required to repair or  
3 replace the damaged equipment subject to limitations of liability specified in the  
4 contract.

5 Q. Was this incident covered by any insurance policies that I&M holds?

6 A. Yes. I&M maintains insurance with Nuclear Electric Insurance Limited (NEIL).  
7 The NEIL insurance policies that I&M maintains include comprehensive coverage  
8 for both property damage and accidental outage.

9 Q. What steps did I&M take to return Unit 1 to service in a safe, timely, and reliable  
10 manner?

11 A. The recovery effort was quite significant in scope. It amounted to a major  
12 construction project to repair and rebuild the plant to correct any damage done by  
13 result of the turbine blade failure. As always, the safety of the workers performing  
14 this recovery work was of utmost importance.

15 Each of the three 39-foot long, 190-ton LP turbine rotors suffered blade  
16 damage and shaft bowing during the incident. Reblading, shaft straightening, and  
17 high-speed balancing was performed by Siemens at their turbine facility in  
18 Charlotte, North Carolina. Originally, it was not certain if the straightening  
19 process would be successful on shafts that large or that bowed. But the  
20 combination of heating, high-speed spinning, and machining returned all three  
21 rotors to within required tolerances. If this process had not been successful, Unit

1       1 could have been off-line well into 2011 while replacement rotors were  
2       fabricated.

3               The main generator and high-pressure turbine were original General  
4       Electric plant equipment. The high-pressure turbine rotor was rebladed and high-  
5       speed balanced at the GE facility in Schenectady, NY. The high-pressure turbine  
6       casings also required machining, structural weld repairs, and installation of new  
7       fixators in the foundation.

8               The main generator rotor was not extensively damaged but was shipped  
9       to a GE facility near Chicago for inspection and servicing. The 500-ton main  
10      generator stator was also lifted off the building foundation and placed on a new  
11      fixator foundation for alignment. There was a brief fire during the turbine event  
12      that was caused by the release of hydrogen that is used to cool the generator and  
13      support equipment. The main generator voltage output bushings, temperature  
14      thermocouple probes and other support equipment were damaged by the fire and  
15      were repaired by the AEP Central Machine Shop.

16              The 12 large bearings that connect the four turbine rotors and one  
17      generator rotor together as a common shaft were either replaced or rebuilt. The  
18      cone extensions between the bearings and exhaust hoods also required  
19      extensive structural welding repairs and laser-aligned machining.

20              The turbine failure also damaged piping, pipe supports, and insulation.  
21      There was also damage to the turbine control system and the 15,000-gallon

1 turbine lube oil system. Twenty-three large motors were removed, shipped off-  
2 site for inspection to determine if repair was feasible, and reinstalled or replaced.

3 Q. Did I&M act reasonably to return the unit to service as soon as reasonably  
4 possible?

5 A. Yes. I&M assembled a large team of employees, industry experts, vendors and  
6 contract workers to accomplish our primary goal to safely return Unit 1 to service  
7 as soon as practicable in a manner that would ensure safe and reliable  
8 operations. I&M collaborated closely with all of its vendors during recovery from  
9 this event to address the elements in all three phases of the recovery timeline.  
10 During the outage, damaged plant equipment was repaired on site if possible, but  
11 all of the major turbine generator equipment for Unit 1 was sent offsite for  
12 inspection, assessment, and repair. Contracts were promptly issued for  
13 replacement parts and new and repaired components timely delivered to the  
14 Cook Plant.

15 Q. When did the Unit 1 turbine outage end?

16 A. The outage was completed safely and in a timely manner and start-up of the Unit  
17 1 reactor occurred on December 18, 2009, and the initial connection to the  
18 transmission grid occurred early the following morning.

19 Q. Was it possible to return the unit to service at this time operating at its normal  
20 maximum electrical output?

21 A. No. To return the unit to service at this time required I&M to leave off the L-0

1 turbine blades because of the design issues associated with those blades. As a  
2 result, the unit is operating with an average unit derate of approximately 35 MW.  
3 This number may vary by season. The repaired LP turbines will be replaced with  
4 a new turbine design at the first opportunity during a future refueling outage (likely  
5 September 2011), at which point the unit is expected to return to its normal full-  
6 load rating.

7 Q. Why did I&M return the unit to service at a derated level, rather than wait until the  
8 turbine could be completely restored?

9 A. I&M performed an economic analysis considering the cost of operating the unit at  
10 a derated level versus potentially continuing the outage until the unit could be  
11 brought back at its full capacity. I&M determined it was better to return the unit to  
12 service at less than its full capacity because waiting for a replacement turbine  
13 would have caused the unit to be out of service until late 2011.

14 Q. Did the Nuclear Regulatory Commission's (NRC) review the Unit 1 turbine  
15 outage?

16 A. Yes. The NRC conducted a special inspection related to the fire protection  
17 aspects of the event described above and reported no violations. The NRC  
18 maintained its normal inspection and oversight role with respect to Unit 1  
19 continued operations with fuel in the reactor, and I&M's recovery efforts from the  
20 Unit 1 event. In addition, the NRC maintained its normal inspection and oversight  
21 role of Unit 2 operations.

1 Q. In your opinion, was the Unit 1 outage caused or prolonged by I&M's  
2 mismanagement or imprudence?

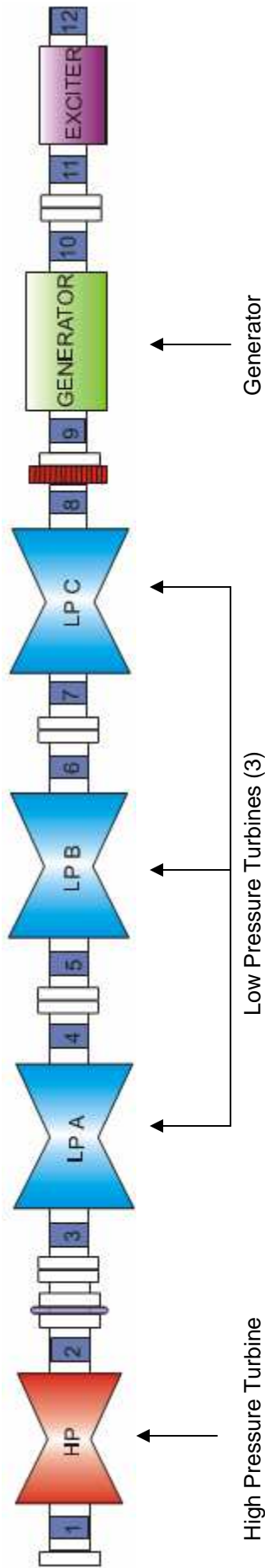
3 A. No. From the beginning of the project to replace the turbine rotors, through the  
4 event of September 20, 2008, and continuing through the recovery efforts, I&M  
5 has acted prudently. This includes the selection of a world class vendor to  
6 upgrade the LP turbine rotors, the negotiation of extended warranty provisions,  
7 proper levels of analysis and supervision in the design and manufacture of the  
8 turbines, and maintaining directly applicable insurance coverage for both property  
9 damage and accidental outage. Furthermore, I&M conducted a pragmatic and  
10 successful recovery effort. We consulted with other utilities that have had similar  
11 events, engaged industry experts to assist in the recovery, and worked very  
12 closely with all vendors and contractors to ensure the unit was returned to service  
13 in a safe, timely, and reliable manner.

14 Q. Does this conclude your direct testimony?

15 A. Yes.

# Cook Unit 1

## Main Turbine-Generator Overview





LPB L-0 Stage



**ROOT CAUSE ANALYSIS OF**

**UNIT 1 MAIN TURBINE GENERATOR TRIP  
SEPTEMBER 20, 2008  
CONDITION REPORT (CR) 00838732**



Root Cause Evaluator	<u>See Route List Notes</u>	Date <u>3/26/09</u>
	J. Nadeau	
Management Sponsor	<u>See Route List Notes</u>	Date <u>3/26/09</u>
	R. Hruby	
CARB Approval	<u>#466</u>	Date <u>3/26/09</u>
	CARB Number	

## UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732**

**EXECUTIVE SUMMARY**

PROBLEM STATEMENT

The Unit 1 reactor was manually tripped following elevated vibrations from the Main Turbine and a reported hydrogen fire from the Main Generator.

EVENT DESCRIPTION

On September 20, 2008, at 20:05 the DC Cook Unit 1 Reactor was manually tripped due to high main turbine generator vibration. A hydrogen fire occurred in the Main Generator high voltage bushing area below the Main Generator. Immediately following the reactor trip, the Unit 1 Main Turbine Generator tripped and the vacuum breakers were opened to stop the turbine rotation. The hydrogen fire required entry into the Emergency Plan (Unusual Event). No abnormal system parameter indications were noted prior to the event.

EVENT CONSEQUENCE AND SIGNIFICANCE

There was no radiological impact related to the identified condition. The nuclear and operational impacts included the reactor trip, emergency plan entry, a hydrogen fire and a Maintenance Rule Functional Failure of the main turbine generator. This event was reported under three conditions:

- 1) 10 CFR 50.72(a)(1)(i), Declaration of an Emergency Classification,
- 2) 10CFR50.72 (b)(2)(iv)(B) for actuation of the Reactor Protection System (4 hour report), and
- 3) 10CFR50.72 (b)(3)(iv)(A) for automatic actuation of the Auxiliary Feedwater system (8 hour report).

The actual consequences of the identified condition were lost generation and significant damage to the turbine generator and surrounding equipment. There was a release of Main Turbine lube oil to the absorption pond, which is documented in CR 00839054. No personnel were injured as a result of the event; however, an emergency responder was injured during the response resulting in a restricted duty.

ROOT CAUSE AND CORRECTIVE ACTIONS TO PRECLUDE REPETITION

Root Cause Statement – This analysis concludes that the root cause of the D.C. Cook Unit 1 turbine failure was a blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades.

The Corrective Action to Preclude Repetition is to modify the design, installation and testing to account for the stressors.

## UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732

### 1.0 PROBLEM STATEMENT

The Unit 1 reactor was manually tripped following elevated vibrations from the Main Turbine and a reported hydrogen fire from the Main Generator.

### 2.0 DETAILED EVENT DESCRIPTION

On September 20, 2008, at 20:05 the DC Cook Unit 1 Reactor was manually tripped due to high main turbine generator vibration. A hydrogen fire occurred in the Main Generator high voltage bushing area below the Main Generator. Immediately following the reactor trip, the Unit 1 Main Turbine Generator automatically tripped and the vacuum breakers were manually opened to stop the turbine rotation. The hydrogen fire required entry into the Emergency Plan (Unusual Event). No abnormal system parameter indications were noted prior to the event. The Trip Report Abstract is contained in Attachment 6.2

On September 20, 2008, the Unit 1 Reactor Operator reported numerous simultaneous control room alarms on the secondary side with severe vibrations and rumbling from the turbine deck. All the vibration points were red indicating high-high vibration. The Reactor Operator immediately tripped the reactor and opened the vacuum breakers to stop turbine rotation. Up until this moment the Unit was operating normally at full power. Review of plant data shows no prior indication of a plant equipment malfunction. The digital fault recorder showed nothing unusual with the Unit 1 Main Generator prior to the trip. Non Essential Service Water (NESW) temperature and condenser vacuum were stable as well. The first sequential event alarm was received at 20:04:59. Within one second there were 17 separate alarms on heater levels being extremely high. This alarm sequence corresponds to an instantaneous initiation of very high vibration in the turbine building. A manual reactor trip occurred five seconds later. The first Main Turbine bearing drain temperature high alarm came in two seconds after the initiating alarm followed by several more at seven seconds after the initiating alarm. Turbine historical alarms show that within two seconds of the first alarm there were High Vibration or High High Vibration alarms on all twelve bearings with bearing # 3 alarming first.

The high vibrations were initiated by a loss of mass from the turbine. Five Low Pressure (LP) Turbine Blades were liberated. On LP Turbine B, two L-0 blades were liberated due to high cycle fatigue and two were liberated due to overload from the event. On LP Turbine C, one L-0 blade was liberated due to high cycle fatigue. The high vibrations caused significant equipment damage including a break in a main generator hydrogen cooling line resulting in the hydrogen fire.

#### Cook Unit 1 Main Turbine Operational Background

The Cook Unit 1 Main Turbine consists of one high pressure turbine and three low pressure turbines (LP-A/B/C). Each turbine rotor is supported by two journal bearings (Bearings 1-8). The original General Electric (GE) LP turbine inner casings and rotors were replaced during the fall 2006 refueling outage with casings and rotors designed and manufactured by Siemens. After the replacement, the turbine was operated within design

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specifications. At the time of the event, the turbine was approximately five months into the second cycle of operation since the replacement.

In August 2006, after delivery of the turbine rotors and just prior to the turbine replacement, Siemens notified Cook Nuclear Plant (CNP) personnel of a turbine system torsional issue, found by the application of a new analysis code by Siemens. This notification was followed by Transmittal SPG-CNP-1067, '*DC Cook Unit 1 Torsional Issue Notification*' dated 8/28/2006 and S32M7 / 2005 / 10444- Rev.2, '*Torsional Studies for AEP, DC Cook Unit # 1 with 18m2 LP Rotor Retrofit*' dated 9/11/2006. These documents described the issue and recommendations for resolution. As a result, Siemens requested that the L-0 blades be shipped back to Germany to weld tuning weights weighing approximately 400 grams on the tips of the L-0 blades to address the torsional issue. The L-0 blades were modified by Siemens, frequency tested, and returned for installation with a modified location map to address the new blade weights. The LP Turbine replacement was subsequently completed during the fall 2006 refueling outage.

The turbine experienced higher vibration than Siemens expected during startup of the turbine. After balancing, was completed all vibration levels were less than seven mils. Bearing vibrations on #5 and #6 bearings were determined to be acceptable (at less than seven mils) but higher than desired (less than five mils). Therefore, a balance adjustment was planned for the Unit 1 rotor during the refueling outage in spring 2008. Review of shaft orbit plots also indicated that the final shaft alignment left the #5 and #6 bearings in a lightly loaded condition. Less than the expected data was collected from torsional testing during startup because the strain gauges fell off. Siemens and CNP concluded that sufficient data was collected and that torsional testing was acceptable. In addition to the normal turbine bearing vibration testing, Siemens specified and conducted both torsional testing, and *Berührungslose Schaufel Schwingungs Messung* (BSSM) testing for startup. BSSM testing is the monitoring of blade vibration. BSSM testing was conducted, at CNP, during startup with two magnetic proximity probes monitoring the blade tips on each of the L-0 rows. The Siemens Root Cause Team identified that BSSM testing was secured at 95% power and did not envelop the operational conditions at which CNP normally operated. Siemens concluded, at the time of test, that sufficient data had been collected and that the BSSM testing was acceptable.

From November 2006 to February 2008, turbine vibrations were observed to be sensitive to condenser vacuum and lube oil temperature changes. Around 23:00, on February 1, 2008 operators observed an increasing trend in turbine vibrations. On February 2, 2008, at 05:30 the operators manually tripped the turbine on high vibrations at 13.8 mils on the shaft (CR 00825512). CR 00825512 identified that the apparent cause of the high turbine vibration was the inherent rotor second critical speed being too close to operating speed, coupled with a relatively high as-left unbalance condition (seven mils) coming out of the November 2006 outage, following the initial installation of the new LP rotors. These two conditions created a relatively unstable condition in the LP B rotor which made it more sensitive to changes in other operating parameters. Contributing causes were 1) failure to correct the non-functioning oil temperature control valve 1-WRV-970 which caused an

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oil temperature excursion and 2) bearings #5 and #6 being relatively more lightly loaded than the other bearings. Both of these conditions contribute to oil whirl/whip (shaft instability) per the published literature on the subject.

Actions were taken to repair the lube oil control valve and to better control lube oil temperature. The shaft was balanced to around four to five mils vibration at the bearings. Shaft vibrations remained stable until the April 2008 refueling outage. During the refueling outage, coupling concentricity was improved, and the lube oil control valve was replaced. Additional balancing was not needed to achieve < 4.5 mils vibration at full load. Also during this outage, an over speed test was performed to validate that there was a second critical speed close to the operating speed. Therefore, actions were proposed in CR 00825512, to stiffen all the LP bearing supports, in order to improve the separation of the second critical and operating speed. The turbine operated with acceptable vibrations until this event on September 20, 2008.

Overall, the Root Cause Team concluded that operational background supports that the Unit 1 turbine was operated within specifications between initial installation in November 2006 and this event on September 20, 2008. Actions were taken in February and April of 2008 to improve vibration performance and additional actions were planned at the next window of opportunity after the solution to further separate the second critical frequency was determined. Actions planned to stiffen the bearings to further separate the second critical, from the operating frequency were determined to be long term improvement items and not threatening to turbine performance.

### 3.0 EVENT OR CONDITION ANALYSIS

#### 3.1 ANALYSIS OF CAUSAL FACTORS

A Failure Investigation Process (FIP) Team established the reason for the Main Turbine Generator failure using a Fault Tree and Support Refute Analysis (Attachments 6.3 and 6.4). From the established equipment failure mode, Performance Improvement International (PII) examined the turbine failure using Failure Diagnostics (Attachment 6.7) to establish the equipment root cause. In parallel, with the PII Failure Diagnostics and with PII assistance, the Root Cause Team assessed the organizational and programmatic barriers using an Equipment Failure Evaluation Checklist (Attachment 6.5), a Barrier Analysis (Attachment 6.6) and a Why Staircase (Attachment 6.9). A Glossary (Attachment 6.12) contains definitions to help in the understanding of this analysis.

The organizational responses to this turbine event and the Fire Protection Equipment failure are outside the scope of this root cause. Refer to CR 00838833 (East Diesel Driven Fire Pump Damage), CR 00838929 (Ruptured Fire Header), CR 00838930 (North Fire water Tank Emptied), and the reactor trip review for details outside the scope of this Root Cause Evaluation.

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The FIP Team Fault Tree and Support Refute analyses (refer to Attachments 6.3, and 6.4) determined that the high vibrations were initiated by a ‘loss of mass’ from the turbine. Specifically five Low Pressure (LP) Turbine blades were liberated, four L-0 blades from LP Turbine B, and one L-0 blade from LP Turbine C. The high vibrations resulted in significant equipment damage including;

- a hydrogen fire,
- a broken fire main,
- broken bearings and bearing fasteners,
- internal and external casings,
- main generator,
- turbine internal support structure,
- turbine sill plate supports,
- turbine rotating and fixed blades,
- turbine rotor, and
- other secondary plant equipment.

PII and Siemens also concluded that the equipment initiating event for the high vibrations was a ‘loss of mass.’

The FIP Team, PII, and Siemens reviewed installation, testing, and operational history of the Unit 1 Turbine since October 2006, and concluded that the turbine had been operated within design parameters. Refer to the following attachments for the supporting analysis that the turbine was operated properly until the high vibration trip on September 20, 2008.

- Attachment 6.7 *PII FAILURE DIAGNOSTIC CONCLUSIONS* and Assignment 00838732-12– Attach PII Root Cause Report to this CR.
- Attachment 6.2 *TRIP REPORT ABSTRACT*
- Attachments 6.3 *FIP FAILURE MODE CHART* and 6.4 *FIP SUPPORT REFUTE MATRIX*

The preliminary Siemens review of operational data also supported that the turbine was operated within limits. As of this writing, Siemens has not completed their root cause analysis. Assignment 00838732-13– is to review the report after Siemens completes its analysis.

The Reactor and Turbine Trip review of the September 20, 2008 event, Attachment 6.2 *TRIP REPORT ABSTRACT*, supports that the Operator Actions and Plant response were performed correctly and mitigated the amount of turbine damage.

The initial PII, Siemens and FIP Team findings that the failure mechanism was a ‘loss of mass’ were validated by the Root Cause Team by comparing the overall investigation strategy and analysis to the Electric Power Research Institute (EPRI) documents on turbine failures. The most significant resource was EPRI, 1014137 ‘Steam Turbine Blade Failure Root Cause Analysis Guide.’ The FIP included both PII and Siemens personnel. The FIP investigation strategy aligned well with the first Investigation Phase contained in EPRI, 1014137; Phase 1: Failure Evidence and Phase 2: Engineering Analysis.

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PII further evaluated the cause of the ‘loss of mass’. The PII Failure Diagnostics are contained in the PII Root Cause Report documented in Assignment 00838732-12. Section 10 of this report concludes that:

“This analysis concludes that the root cause of the D.C. Cook Unit 1 turbine failure was a blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades. This caused those three blades to occasionally exceed their stress threshold at the highest stress location thereby suffering high cycle fatigue cracking. Variations in the attachment engagement of individual blades may have been the reason why only three blades displayed the cracking. The normal blade design was modified by adding a welded tuning weight to the tip which could lead to additional variation in each blade. Normal minor electrical grid variations correlate well to the distinctive beach marks observed....”

The root cause identified by PII is supported by, EPRI 101437, Page 2-34 which states;

“In general, when the evidence indicates that the problem is initiated by Low Cycle Fatigue (LCF) or High Cycle Fatigue (HCF), this points to a problem with the blade design. If the material is up to its required standards, and/or the installation is performed correctly, it is reasonable to suspect that operating stresses are exceeding what the original designer assumed or calculated. In such scenarios, corrective action is likely going to require replacement of the row with a modification designed to reduce or minimize steady, dynamic, and/or thermal stresses by a significant amount.”

PII findings were validated by comparing the overall investigation strategy and each of the analysis sections to EPRI, 1014137 ‘Steam Turbine Blade Failure Root Cause Analysis Guide.’ The overall investigation strategy aligned well to the three Phase approach contained in EPRI, 1014137; Phase 1: Failure Evidence, Phase 2: Engineering Analysis and Phase 3: Corrective Actions. The individual analysis, cause and corrective actions sections also aligned well with the technical discussion contained in EPRI, 1014137. Lastly the team concentrating on turbine recovery and the Root Cause Team were organized as separate teams to ensure appropriate focus by each team as recommended in EPRI, 1014137.

#### Phase 1: Failure Evidence Validation

As noted above in the FIP discussion, evidence collection aligned well to EPRI, 1014137 resulting in a conclusion that the turbine failed due to a loss of mass. Based on examination of the failed blade fracture surfaces, the PII report further identifies that this loss of mass was from High Cycle Fatigue (HCF) on blades #40 and #56 in LP B, and

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#189 in LP C. This conclusion is based on beach marking observed and operational history reviewed. This conclusion is consistent with EPRI, 1014137, Section 2.

Phase 2: Engineering Analysis Validations

The Blade Inspection Section 5 of the PII report discussed the four fracture zones on the surfaces of Blades #40, #56, and #189, (Incubation, Initiation, Propagation, and Rupture). In the Fractography Timeline, PII identifies that the failure was due to High Cycle Fatigue and draws two major points that are used to support the root cause. First, on page 24, "...the beach marks may have been the direct result of routine minor electrical variations in the Cook Switchyard that translated into rapid changes in generator resistance. These changes then traveled through the rotor to individual blades in the LP turbines." Second, on page 27, "Clearly the stresses were higher on the three blades in question. It is important to note, however, that during the first roughly 40% of the process, the stress cycles are doing damage that is undetectable by crack detection methods. It is quite likely that other blades experienced these same cycles but that due to having lower steady state stresses the allowable number of cycles was higher for those blades and so they remained in the Incubation stage. This is probably why none of the remaining blades showed indications of cracking in the root area." EPRI, 1014137 support these points.

From EPRI, 1014137, Section 2 – Damage Mechanism and their Root Causes;

On page 2-5 EPRI, 1014137 discusses four practical phases of crack growth; Incubation, Initiation, Propagation, and Rupture, and contains a picture that is similar to CNP blade failure. On page 2-6 EPRI, 1014137 identified in part:

"Well-designed blades will remain within these two phases (Incubation and Initiation) for their entire service life because of the safety factors and design margins that are present to accommodate the damage caused during operation. A failed blade has moved into one or both of the remaining phases. (Propagation or Rupture) Propagation is a reflection of the damage tolerance inherent within the design. If initiation and propagation are both a result of HCF, the remaining life is rapidly consumed and normally catastrophic as a result of the hundreds of cycles at which the modes naturally vibrate."

From EPRI, 1014137, Section 5 – Off Site Forensics: Metallurgical Examination;

"...only about 50–70% of a part's fatigue life is represented by the propagation portion of the fatigue crack. Thirty percent to 50% of the life is used in incubation and initiation. Thus, during the first third to half of the unit's operating history, events might not be visible on the fracture surface...."

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The Executive Summary and Section 6 – Blade Testing of the PII report identified that root dimension variation are a likely contributor to the blade stress.

From EPRI 101437, Page 10-5;

“Tolerances in root attachments are critical. If the gaps between pairs of load bearing hooks are not uniformly maintained to within certain minimal criteria, (usually within  $\pm 0.5$  mils [0.01 mm]), the centrifugal forces at full speed will not be sufficient to close them. The result will be to have the loads redistributed among the remaining pairs where contact is achieved....”

Section 7, Plant Performance Review, of the PII report considered those attributes recommended in Section 8 of EPRI 1014137. PII identifies that the turbine was operated within the design specified operational limits.

### Phase 3: Corrective Actions Validation

The recommended corrective actions by PII are included in Section 11 of the PII report. In general, these recommendations are to modify the LP turbine design to eliminate the high stress condition in the L-0 blades. Along with this design change, PII is recommending a third party assessment of the potential failure modes to ensure adequate design margin is specified and achieved. These recommendations are consistent with those discussed in EPRI, 1014137, Section 9. The actions selected for this Root Cause Evaluation are contained in Section 4 of this report, are consistent with the PII recommendations and are consistent with EPRI recommendations for corrective actions dealing with design issues.

The FIP Team, PII and Siemens all agree that the ‘loss of mass’ was initiated by High Cycle Fatigue (HCF) on blades #40 and #56 in LP B and #189 in LP C. The FIP Team turned over to this Root Cause Team on November 17, 2008, after agreement was achieved that the initiating event was loss of mass. PII performed an Equipment Root Cause Analysis as part of this Root Cause Evaluation, which determined that the HCF was caused by a blade-rotor system design that which failed to provide adequate stress margin in at least three L-0 blades. The Siemens evaluation as of March 9, 2009, had not determined a root cause.

### Root Cause Team Organizational and Programmatic Evaluation

A *BARRIER ANALYSIS* (Attachment 6.6) was used to evaluate CNP personnel and Siemens interfaces from the point that the Unit 1 Turbine Replacement Project was initiated until September 20, 2008. The purpose of this analysis was to determine if there were any CNP organizational or programmatic influences that may have caused, or contributed to the event in order to minimize the potential for a similar event in the future. The analysis also looked for any lessons to be learned that could be used to improve CNP performance in the future.

***PMP-7030-CAP-002 defines a contributing cause as: “A factor which did not directly cause the inappropriate action(s), or equipment failures that led to the condition, but may***

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*have increased the consequences or represented an impaired barrier. Elimination of a contributing cause may not preclude repetition of the event, but should either reduce the probability or the consequences of the event.” Lessons Learned may be from either causes, or other improvement opportunities not directly tied to the cause of the event.*

The Barrier Analysis supported the design related root cause. As detailed in Attachment 6.6, no CNP Organizational or Programmatic contributing causes were found. A summary of the Root Cause Team’s review of CNP organization decisions made regarding the turbine and L-0 blades follows.

CNP appropriately provided the turbine upgrade request for proposal to three world class vendors with the necessary technical expertise and experience. CNP also appropriately selected the replacement turbine based on meeting all the request for proposal requirements and providing the best net present value. This value came from all of the considerations offered by the Siemens product including the increased efficiency from replacing all three LP turbines with a new 18m<sup>2</sup> L-0 free standing blade design. The turbine 18m<sup>2</sup> L-0 blade design was a first of a kind, new design, that was not extrapolated from an existing design.

Once the turbine replacement design was selected CNP conducted appropriate risk reviews, operating experience reviews and benchmarking. These reviews and benchmarking resulted in applying additional controls and testing to ensure that industry events did not repeat at CNP. Based on the identified risks, CNP also chose to apply quality and technical oversight to the vendor in excess of what was required by the process.

When the torsional issue was identified by Seimens just prior to the turbine replacement installations, the appropriate questions were asked by CNP and resolved by Seimens. CNP engaged third party reviews and assigned a turbine engineer to follow the modification in Germany. The issues, risks, proposed solutions and contingency actions were appropriately elevated to CNP Senior Management.

CNP Personnel believed that the turbine, including L-0 blades, was thoroughly tested after initial installation, during the startup from the U1C21 refueling outage. These tests included the BSSM testing of the L-0 blades, and torsional testing of the shaft line. The BSSM testing monitored the blade tip movement during all phases of startup including variations of condenser vacuum. Note that the Siemens Root Cause Team identified that BSSM testing was secured, at 95% power, and did not cover all of the conditions at which Unit 1 normally operated. Therefore, the Siemens Root Cause Team did not have data available from the BSSM testing to completely refute aeroelastic excitation. The Seimens Root Cause Team is further evaluating the aeroelastic mechanisms. CNP Turbine Replacement Project personnel were unaware that BSSM testing data was not collected above 95% power. CNP Turbine Replacement Project personnel were aware of the decision to complete the torsional tests without the strain gauges. CNP personnel approved the decision to startup with less than or equal to seven mils vibration. These testing results, as provided by Siemens in 2006, indicated that the turbine performed well. Siemens recommendation for these blades was to perform a visual inspection during each refueling outage and to inspect the LP rotors on a 10 year inspection interval.

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The inspections and testing performed were consistent with the manufacturer's recommendations and there was no industry OE that suggested an enhanced inspection program was needed. In fact, Siemens' OE with replacement of GE nuclear turbines in Limerick and Susquehanna revealed no problems with cracking of 13.9m<sup>2</sup> L-0 blades.

CNP personnel also believed that the inspections and tests specified by Siemens were appropriate based on CNP experience with Unit 2. CNP Operating Experience with free standing L-0 blades on Unit 2, which are a similar design by a different manufacture, has been very good. Visual inspections of the Unit 2 L-0 blades are performed during each refueling outage. A more thorough NDE inspection is performed during each Unit 2 LP rotor inspection on a Four Refueling Cycle (4R) frequency.

The February 2008 vibration trip was considered a rotor vibration or stability issue and there was no evidence that the issue had any causal relationship with the L-0 blade failure. The information about the bearing support stiffness was not fully apparent until after the spring 2008 refueling outage was over. Since the spring 2008 refueling outage completion, CNP personnel were working with Siemens to provide drawings to add stiffening at the bearing supports. This work was included in the U1C23 outage scope and will now be completed before restarting the unit. There was no evidence that the bearing support issue had any relationship to the L-0 blade failures.

Overall, the Root Cause Evaluation team concludes that CNP organization decisions made in the initial installation and testing of the turbine showed a reliance on the vendor, which was supported by the vendors industry standing and CNP oversight of the vendor. These decisions were reasonable, prudent, and in-line with best industry practices based on the information available to CNP personnel prior to September 20, 2008.

An improvement opportunity was identified by review of CNP oversight of quality and technical witness points. This improvement opportunity is addressed below, in Section 3.6, and in Section 4.4.

Improvement Opportunity

The procurement of the Unit 1 LP turbine used the standard grade procurement process. CNP personnel selected Siemens, a world class vendor with significant experience in turbine retrofits. CNP personnel relied upon Siemens' expertise for the design, manufacture, testing and installation of Siemens turbine retrofit designs. CNP personnel specified appropriate operational requirements to Siemens. These actions are consistent with standard grade procurements.

In addition to normal standard grade procurement requirements, CNP obtained and reviewed technical and quality related data supporting the turbine manufacturing and testing as identified in the Barrier Analysis. CNP did not observe all of the quality and technical oversight witness points allowed by contract. Refer to the Barrier Analysis for the details on the quality and witness points observed. CNP obtained adequate confidence

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in the vendor design based on; review of industry OE, the quality and witness points reviewed, and the testing specified to validate turbine performance.

Siemens designed the LP Turbine system. Siemens manufactured and tested the turbine in accordance with Siemens' design. The Root Cause Team reviewed the data associated with each of the quality and witness points and did not find any data outside manufacture specifications. Therefore, the RCE team concluded that, additional CNP verification of quality and technical witness points to verify design, manufacture, or testing would not have affected the outcome.

Although a graded approach to quality was applied to the turbine project, it was found that CNP did not have a formal process defining this approach. This observation did not contribute to the event. The Root Cause Team determined that there would be value for CNP to have a process to apply a graded approach to oversight of standard grade projects based on risk.

Why Staircase:

The DC Cook Unit 1 Reactor manual trip due to high main turbine generator vibration and the related hydrogen fire were both a result of high vibration caused by loss of four LP B L-0 blades and one LP C L-0 blade. Two LP B blades failed due to high cycle fatigue. The failure of these blades caused two additional blades to fail in overload. One LP C blade failed on high cycle fatigue. The three blades, which failed on high cycle fatigue, failed because the blade-rotor system design failed to provide adequate stress margin in at least three L-0 blades. This caused those three blades to occasionally exceed their stress threshold at the highest stress location thereby suffering high cycle fatigue cracking. This root cause statement was validated by going two 'whys' below the root cause in the technical why staircase and by six 'whys' deep on the CNP Organizational and Programmatic timeline to ensure that the type of proposed corrective actions would not change. In each case, the types of corrective actions needed are related to re-design of the blade-rotor system to provide adequate stress margin.

Attachment 6.5 contains Data Sheet 2- Equipment Failure Evaluation Checklist. The checklist concluded that: "The Root Cause Evaluation identified concerns with the Main Turbine design resulting in a high stress conditions in the L-0 blades. The Zero Tolerance classification does not allow any failures. The Maintenance Rule criterion is monitored at the Plant Performance level. These classifications are appropriate."

### **3.2 EXTENT OF CONDITION AND EXTENT OF CAUSE**

The condition applies to the Cook Unit 1 Main Turbine Generator. The Cook Unit 1 Main Turbine Generator was a first of a kind design to replace the General Electric (GE) LP turbine with Siemens LP turbine rotors with 18m<sup>2</sup> last stage blades in November 2006. This condition does not apply to Unit 2 which is a Brown Boveri turbine or other Cook turbines which have performed satisfactorily as described below.

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In comparing the Unit 2 L-0 blades to the Unit 1 Siemens L-0 blades that failed on September 20, 2008 both designs are free standing blades with curved axial entry blade root design. The Siemens Unit 1 L-0 blades are 56" long and weigh approximately 250 pounds each. There are 50 blades in each row. The Unit 2 Main turbine is a Brown Boveri Corporation design, (currently Alstom) and are 52" long and weigh approximately 220 pounds each. There are 63 blades in each row. The Siemens Unit 1 LP turbine catastrophically failed well before its first planned 10 year rotor out inspection. During inspections of the three Unit 2 LP turbines, approximately 12 L-0 blades were replaced due to minor indications and one L-1 blade was replaced due to a more significant crack in the blade root section. There have been no failures during operation of any turbine blades on Unit 2 Main Turbines.

The Unit 1 High Pressure (HP) 1st stage buckets failed in January 1982. This was attributed to partial arc admission control valve operation, which was the original design for the HP turbine. The Unit 1 HP was converted to full arc admission and has operated that way since 1982. The HP has been inspected as recently as April of 2008 with no problems identified with these buckets.

All other turbine rotor/blade combinations, including the Unit 1 & 2 Feed Pump Turbines, the Unit 1 Main HP Turbine and the Unit 2 Main HP and LP Turbine, have all surpassed any infant mortality issues having been in service for over 30 years. Any blade attachment issue that may reduce the design margin of any of these blades would have presented itself well before now. Routine inspections of the rotors and blades according to OEM recommendations helps ensure detection of any degradation before it would reach the point of failure.

Operating Experience (OE) was shared with the industry via OE 27590 and 27695.

The cause of this condition was blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades. This cause is potentially transferable to the Unit 1 HP turbine modification or new turbine modifications of Units 1 or Unit 2 to support unit up rates. Actions contained in Sections 4.1 and 4.5 address this extent of cause.

Attachment 6.12 – Safety culture survey concluded that there was not a safety culture impact associated with this event. A safety culture component search was conducted using codes applied in Asset Suite based on safety culture components. A trend was not observed.

### **3.3 SAFETY SIGNIFICANCE**

There was no radiological safety significance to this event. The actual operational impacts and nuclear safety significance were bounded within the current licensing basis. The potential industrial safety significance was more severe than the actual industrial safety significance.

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The nuclear or operational impacts included the reactor trip, emergency plan entry, a hydrogen fire and a Maintenance Rule Functional Failure of the Main Turbine Generator.

The Unit 1 reactor was manually tripped following elevated vibrations from the Main Turbine and reported hydrogen fire from the Main Generator. These events resulted from a loss of five L-0 blades. A Notification of Unusual Event (NUE) was declared at 20:18 and the fire reported extinguished at 20:28. This event was reportable due to activation of the site Emergency Plan (H-4, Fire within the protected area not extinguished within 15 minutes and H-5, Toxic or Flammable gas release {Hydrogen} affecting plant operation {required Reactor/Turbine trip}).

This event was reported under three conditions:

- 1) 10 CFR 50.72(a)(1)(i), Declaration of an Emergency Classification,
- 2) 10CFR50.72 (b)(2)(iv)(B) for actuation of the Reactor Protection System (4 hour report), and
- 3) 10CFR50.72 (b)(3)(iv)(A) for automatic actuation of the Auxiliary Feedwater system (8 hour report).

Attachment 6.2 *TRIP REPORT ABSTRACT, SEPTEMBER 20, 2008* contains the details of the expected and unexpected equipment responses.

Extensive post event walk downs verified that there was no structural or primary system damage. The Unit 1 Plant Air Compressor (PAC) was considered unavailable when it was found that its auxiliary oil pump had lost power apparently due to the turbine generator failure/fire.

A Probabilistic Risk Analysis (PRA) of this event was conducted to support the Licensee Event Report (LER) and concluded:

‘In summary, based on review of the control room log and the information above, all plant systems performed as designed to shutdown the unit and remove decay heat following the main turbine failure, and the 9-20-08 trip event did not represent a significant risk. The only PRA functions affected were the failed Unit 1 Plant Air Compressor (PAC), and the inability to manually use the main feedwater system. Main feedwater was unavailable since main condenser vacuum had been broken and its risk associated function is to be manually used in EOPs to mitigate a potential complete AFW failure. PRA-STUDY-053 estimated the “change in Conditional Core Damage Probability” ( $\Delta$ CCDP) using the current Safety Monitor Cook PRA model. The  $\Delta$ CCDP associated with this event was determined to be 7.811E-07. Under “stand-alone” consideration (that is, neglecting any other considerations that may be attached to this event in the form of fire protection system issues or other plant cross-cutting issues), this  $\Delta$ CCDP value represents a nominal increase in plant risk from expected plant performance consistent with NRC Inspection Manual Chapter 0308 “Reactor Oversight Process (ROP) Basis Document,” and Regulatory Guide 1.174, “An Approach for

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using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis.”

The Maintenance Rule Evaluation concluded that this event was a Maintenance Rule Functional Failure (MRFF) based on not meeting Plant Level Performance Criteria ‘MT-01 - Converts thermal energy from the Main Steam into mechanical energy to turn the electrical generator. This includes all necessary support system functions.’ The Maintenance Rule Evaluation determined that this event was not maintenance preventable. The Zero Tolerance Classification in the Equipment Data Base correctly identifies that failures for the turbine are not allowed. These conclusions are consistent with the Root Cause Evaluation.

During the turbine high vibrations there was major equipment damage, a hydrogen fire, and severe vibrations that could have resulted in personnel injuries. Also, vibration induced insulation failures resulted in Potential Asbestos Containing Materials (PACM) and Asbestos Containing Materials (ACM) areas that were sampled and controlled at asbestos concentrations below the allowable limits. The turbine dismantling was more complicated than usual due to equipment damage, equipment movement and extent of dismantlement required.

### 3.4 EVENT CONSEQUENCES

The loss of mass from the Main Turbine resulted in major equipment damage to the turbine generator, turbine sill plate supports, turbine internal supports and turbine surrounding equipment. As described in Attachment 6.2, high vibration caused the Main Generator to immediately separate from the grid. Also, WR 06364959, identifies that 250 VDC pump buss control power circuit breaker, 1-CRCD-7 tripped. As described in CR 00838930, a fire water header pipe coupling separation in the yard adjacent to the Turbine Building resulted in draining the North Fire Protection Water Storage Tank, 12-TK-295N, and damage to the East Diesel Driven Fire Pump, 12-PP-145E. There was a release of Main Turbine lube oil to the absorption pond, which is documented in CR 00839054. The lube oil spill was reported to the Michigan Department of Environmental Quality and the Nuclear Regulatory Commission in accordance with Technical Specifications, Appendix B – Environmental Technical Specifications, Section 3.2. As described in CR 00838927, the vibration resulted in an Asbestos Containing Materials (ACM) release below the limits. These consequences translate into lost production and revenues associated with the equipment investigation and repairs. No licensing basis requirements, regulations or commitments were violated. No personnel were injured as a result of the event; however, an emergency responder was injured during the response resulting in a restricted duty.

### 3.5 OPERATING EXPERIENCE (OE)

The OE and benchmarking that was included in the modification package was reviewed for applicability to the project and to the resultant failure of the L-0 blades on September 20, 2008. Additional searches for OE were also performed in the Cook Nuclear Plant Operating Experience (CNPOE), Institute of Nuclear Power Operations (INPO) and World

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Association of Nuclear Operators (WANO) data bases under the search criteria of “modification,” “turbine vibration,” turbine failures,” and “turbine trip.” The OE search included a review of Significant Event Evaluation and Information Network (SEE-IN) Documents for the failure modes and causes associated with this event. The Corrective Action Program Owners Group (CAPOG) was queried for any Root Cause Evaluations related to turbine failures and three were provided from South Texas Project (STP), Susquehanna, and Point Lepreau. A search of the Ventyx data base was conducted based on cause codes associated with design and project controls. This analysis reviewed the effectiveness of use of OE that was included in the original modification. Also included in this evaluation was a search for other OE that was available during the development of this modification that, if used, could have prevented this event. The Electric Power Research Institute (EPRI) web was searched for available information on ‘turbine failures’ or ‘turbine vibrations’ to use in conducting this root cause and developing actions.

**3.5.1 EXTERNAL OPERATING EXPERIENCE**

**OE Included in the Modification Package**

The OE in the original modification package (1-MOD-40012) included OE related to other Nuclear Plant Main Turbine upgrades that were performed in this country. Some of this experience was related to upgrades by Siemens and some included other vendors. There was also OE related to the project management for major projects, with information on managing the project to ensure success. In addition, the modification package contained benchmarking of both another facility’s turbine replacement and of the AEPSC Turbine Section. The Root Cause Team determined that OE in the modification package was successfully used to specify preventive actions for many technical and project related issues previously identified in the industry. No failure to use OE was linked to the root cause of this event.

A summary is contained in section 3.5.3, and details of the evaluation supporting this conclusion are contained in Attachment 6.8.

The EPRI web was searched for available information on ‘turbine failures’ or ‘turbine vibrations’ to use in conducting this root cause and developing actions. Five documents were found that significantly contributed to this investigation.

- 1) EPRI, 1004963, December 2004, ‘Turbine Condition Assessment and Monitoring Methodology’
- 2) EPRI, 1011679, November 2005, ‘Steam Turbine-Generator Vibration Interaction with Electrical Network’
- 3) EPRI, 1013460, November 2006, ‘Torsional Interaction Between Electrical Network Phenomena and Turbine-Generator Shafts’
- 4) EPRI, 1004559, December 2002, ‘Noncontacting Detection of Turbine Blade Vibration’
- 5) EPRI, 1014137, March 2008, ‘Steam Turbine Blade Failure Root Cause Analysis Guide’

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Documents 1 through 4 above were available to the modification team and CNP System Engineering prior to this event. The Root Cause Team concluded that, although these documents were not referenced in the modification package, the concepts discussed in these documents supported the testing plans for the new LP Turbines that were installed in 2006.

EPRI, 1014137 'Steam Turbine Blade Failure Root Cause Analysis Guide' was issued in March 2008 and was not available to the Modification Team. EPRI, 1014137 was used by the Root Cause Team to validate the PII investigation methodology and actions. The details of this validation are contained in Section 3.1 of this report.

**3.5.2 INTERNAL OE**

Review of eCAP and Ventyx data did not identify any internal OE related to the cause of this event. Internal OE identified in the turbine modification package and in the startup testing was used successfully to prevent other issues. Internal OE on stress corrosion cracking was incorporated into the bid specification. The AEP Turbine Operating Circular Letter -4 (TOCL-4) on Vibration Limits was referenced during startup to specify operating vibration limits.

A summary is contained in section 3.5.3, and details of the evaluation supporting this conclusion are contained in Attachment 6.8.

**3.5.3 PERFORMANCE OF OE**

The OE that was included in the modification provided useful information for specific technical issues and helped to avoid some potential vibration issues during startup due to rubbing on oil seals. The torsional vibration concern was raised with Siemens and evaluated, first with an updated three dimensional model and then later with on line testing. The lesson learned from Calvert Cliffs was used to ensure minimal impact on CNP secondary steam chemistry and to improve the modification performance. The AEP Turbine Operating Circular Letter -4 (TOCL-4) on Vibration Limits was referenced during startup to specify operating vibration limits. The OE related to project management was included in the modification and was used to ensure the project was successful.

Although this event initially appears to have similar circumstances and cause to a turbine failure at STP described in OE15951, CNP took successful actions to prevent the causes of the STP failure at CNP. At STP, Siemens used unvalidated assumptions on Original Equipment Manufacture (OEM) generator torsional frequency. Unlike STP, at CNP, Siemens performed testing of both the GE rotor and Siemens rotors to validate the assumption. At STP, the blades failed in high cycle fatigue caused by a resonance frequency close to 120hz. Unlike STP, CNP and Siemens were aware of the 120hz issue and took measures to avoid 120hz. The failure mode at CNP appears to be different in that only three blades showed extensive cracking and none showed lesser cracking whereas STP had many blades cracked to varying degrees. Therefore, the event is not considered a repeat event because previous OE was acted on and the failure mode was different.

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Operating Experience was shared with the industry via OE 27590 and 27695. An additional action to share the results of this root cause with the industry is contained in action 4.5.4.

**3.6 LESSONS LEARNED**

The Cook Plant Turbine Replacement project team relied on the expertise of its turbine design and manufacturing vendor and provided oversight through various means (e.g., teleconferences, meetings, letters, e-mail, site visits, etc.) at various stages. The lesson learned is that the more significant the consequences associated with a change, the more prevention actions need to be applied. In these cases, CNP should apply additional oversight to both the technical and quality aspects of projects to provide further assurance that the equipment will perform satisfactorily in service. Major projects should include the oversight areas and resource requirements, including third parties, to provide additional oversight of vendors, if needed.

Action 4.4.1.1 incorporates this Lesson Learned into CNP processes.

**4.0 CAUSE(S)/CORRECTIVE ACTIONS**

**4.1 ROOT CAUSE**

Root Cause Statement – The D.C. Cook Unit 1 turbine failure was a blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades. This caused those three blades to occasionally exceed their stress threshold at the highest stress location thereby suffering high cycle fatigue cracking.

**4.1.1 Interim CATPR –**

Modify the design, installation and testing of the interim Unit 1 Low Pressure Turbine (without L-0 blades) to account for all currently analyzed stressors and those identified as potential contributors to the L-0 blade High Cycle Fatigue in the Siemens and PII root cause reports. (PII action 16)

CATPR 00838732-14

Owner: ESY, Due: 10/15/09

CATPR 4.1.1 will be validated by applying the third party review identified in 4.1.3 to Siemens design controls based on a Turbine Generator Failure Mode Diagram.

**4.1.2 CATPR –**

Modify the design, installation and testing of the Unit 1 Low Pressure Turbine to account for all currently analyzed stressors and those identified as potential contributors to the L-0 blade High Cycle Fatigue in the

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Siemens and PII root cause reports. Examples of these stressors from the PII report are:

- Resonances in all modes (PII action 6, Margin)
- Steady state and expected transient stresses (PII action 8, Margin)
- Prototype testing of new blades design (PII action 9)
- Bearing Stiffness and Damping (PII actions 1, 2, and 4; AR 00825512, Margin)
- Aero-Elastic Flutter (Siemens)
- Verify 100% of critical blade attachment clearances as part of the blade manufacturing process. (PII action 15, Margin)
- Complete rotor torsional evaluation (PII action 16, 19, 20)

CATPR 00838732-15                      Owner: ESY, Due: 12/15/11

CATPR 4.1.2 will be validated by applying the third party review identified in 4.1.3 to Siemens design controls based on a Turbine Generator Failure Mode Diagram.

CATPR 4.1.2 will be sustained by reference in the design modification.

4.1.3 CA –

Apply qualified AEP or third party quality and technical oversight to the turbine design, manufacturing, installation and testing to ensure that the appropriate quality attributes are identified and implemented. This review is to include an independent qualified review of new turbine design. (PII action 7, 19, 20)

CA 00838732-16                      Owner: ESY, Due: 12/15/11

4.1.4 GA –

Communicate design process CATPR to Siemens and implement CATPR at Siemens.

CA 00838732-17                      Owner: ESY, Due: 04/23/09

4.1.5 Interim Action –

Apply the third party review described in action 4.1.3 to the Unit 1 turbine interim repair. (PII action 16)

CA 00838732-18                      Owner: ESY, Due: 10/29/09

**4.2 EXTENT OF CONDITION**

The condition applies to the Cook Unit 1 Main Turbine Generator. The Cook Unit 1 Main Turbine was a first of a kind installation of Siemens LP Turbines with 18m<sup>2</sup> L-0 free standing last stage blades in November 2006. This condition does not apply to Unit 2

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which is a Brown Boveri turbine or other Cook turbines which have performed satisfactorily. Operating Experience was shared with the industry via OE 27590 and 27695.

Actions to address this extent of condition are contained in sections 4.1 and 4.5.

**4.3 EXTENT OF CAUSE**

The cause of this condition was a blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades. This cause is potentially transferable to the Unit 1 HP turbine modification or new turbine modifications of Unit 1 or Unit 2 to support power up rates.

Actions contained in sections, 4.1 and 4.5 address this extent of cause.

**4.4 IMPROVEMENT OPPORTUNITY**

4.4.1 Although a graded approach to quality was applied to the turbine project, it was found that CNP did not have a formal process defining this approach. This observation did not contribute to the event. The Root Cause Team determined that there would be value for CNP to have a process to apply a graded approach to oversight of standard grade projects based on risk.

4.4.1.1 Develop a graded approach to technical and quality oversight of non-QAN vendors based on project risk and consequences. Include this guidance as well as when to engage third party reviews of designs in the project and design processes.

CA 00838732-19                      Owner: PRJ, Due: 08/31/09

4.4.1.2 Modify Bid Evaluation Process to include risk associated with proposed design from inputs such as changing OEM/ proprietary information, vendor OE, and equipment history with.

CA 00838732-20                      Owner: BSM, Due: 05/31/09

4.4.1.3 Review current projects to identify those that need to have quality and technical oversight controls applied based on risk. Apply those controls specified in sections 4.4.1, 4.4.1.1 and 4.4.1.2.

GA 00838732-21                      Owner: PRJ, Due: 04/09/09

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**4.5 OTHER CORRECTIVE ACTIONS**

- 4.5.1 Train personnel in Predictive and System Engineering on vibration trace evaluation to promptly identify unacceptable conditions and degrading trends with bearing vibration issues such as oil whirl or light loading. (PII action 3)

TRNE 00838732-22

Owner: TRN, Due: 11/15/09

- 4.5.2 Develop and implement a turbine, testing and monitoring plan for the Unit 1 Siemens Turbines. Consider including the following items in this plan.
- Install and use an in-service torsional vibration monitoring system similar to the one at South Texas Project with specific Operator guidance on allowable operating limits for the replacement rotors. (PII action 18)
  - Perform non-contact L-0 blade vibration measurements using fixed sensors positioned near the rotating row to identify blade fluttering. (PII action 10)
  - Complete BSSM Testing, including normal modes of operation (PII action 11)
  - Monitor the Main Unit Generator for negative sequence currents or grid transient impact. (PII action 12)
  - Use the existing pressure taps to monitor for Diffuser Humming in the area of the L-0 blades. (PII action 13)
  - Install on line monitoring equipment to support continuous performance monitoring.
  - Complete rotor torsional test with all instrumentation attached (PII action 17)

CA 00838732-23

Owner: ESY, Due: 9/15/10

- 4.5.3 Revise the Unit 1 Main LP Turbine Preventive Maintenance (PM) activities to perform non-destructive examination of the accessible portions of L-0 blades with the L-0 blades and rotors in place (i.e. eddy current of phased array). As a minimum perform the PMs at 1R, 2R and 4R to support the effectiveness review. (PII action 14)

CA 00838732-24

Owner: ESY, Due: 5/15/11

- 4.5.4 Share the results of the Root Cause Evaluation with the Industry.

GA 00838732-25

Owner: PRJ, Due: 04/14/09

- 4.5.5 Incorporate Lesson Learned into the Lessons Learned Data Base.

GA 00838732-26

Owner: PRJ, Due: 04/14/09

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4.5.6 Obtain Siemens' input for low pressure turbine bearing stiffening. Action 13 of the EACE 00825512 and Work Order (WO) 55323969-01 'Stiffen U1 LP-B Bearings to Increase Natural Frequency' were specified by CARB #433 and are tracking the change to stiffen bearing supports. Bearing stiffening was scheduled for U1C23 and will now be completed prior to return to service from this forced outage via WO 55323969.

CA 00825512-13

Owner: ESY, Due: 09/30/09

4.5.7 PII and Siemens to resolve differences in blade resonance analyses. (PII action 19)

GA 00838732-27

Owner: ESY, Due: 04/29/09

4.5.8 PII to develop a rotor dynamic model for the Cook turbine train to identify the degree of impact due to torsional resonances. (PII action 20)

GA 00838732-28

Owner: ESY, Due: 04/29/09

4.5.9 Obtain final PII Root Cause Report and attach to this CR.

GA 00838732-12

Owner: PRJ, Due: 04/14/09

4.5.10 Obtain Siemens Root Cause Report, review it and update this CR as needed.

GA 00838732-13

Owner: PRJ, Due: 04/24/09

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732**

**5.0 EFFECTIVENESS REVIEW PLAN**

**5.1 METHODOLOGY**

- 5.1.1 Engage third party vendors to review critical design characteristics of the design of the short term and long term solutions involving the Unit 1 Main Turbine.
- 5.1.2 Develop testing and acceptance criteria for the short term and long term modifications to the Unit 1 Main Turbine prior to and during return to service.
- 5.1.3 Perform monitoring and trending of critical parameters during operation in accordance with plan developed in action 4.5.2.
- 5.1.4 Perform Preventive Maintenance in accordance with the plan developed in action 1.1.1.

**5.2 ATTRIBUTES**

- 5.2.1 The turbine generator shaft line is analyzed by the vendor, a third party and the AEP Turbine Section.
- 5.2.2 Implement testing for the short term and long term modifications to the Unit 1 Main Turbine prior to and during return to service.
- 5.2.3 Implement the monitoring and trending of critical parameters during operation.
- 5.2.4 Implement the Preventive Maintenance activities for both the short and long term solutions.

**5.3 SUCCESS CRITERIA**

- 5.3.1 Analysis of the turbine generator shaft line is analyzed by the vendor, a third party and the AEP Turbine Section and accepted by all parties involved.
- 5.3.2 Testing acceptance criteria are met for both the short term and long term modifications to the Unit 1 Main Turbine prior to and during return to service.
- 5.3.3 Monitoring and trending of critical parameters during operation indicates acceptable performance.
- 5.3.4 The Preventive Maintenance activities created and implemented to perform the inspections and maintenance activities show acceptable performance.

**5.4 TIMELINE FOR COMPLETION**

- 5.4.1 The Unit 1 Main Turbine is returned to service following the repairs to the Main Turbine currently scheduled for September, 2009 and operates, without L-0 blades, meeting the identified success criteria.
  - Provide interim effectiveness review to CARB identifying the results of the third party design review 30 days prior to the interim replacement.
  - Provide interim effectiveness review to CARB identifying the results of the installation testing 60 days after the replacement.
  - Provide effectiveness review to CARB identifying the performance of the interim replacement turbine 30 days prior to the new turbine replacement.

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5.4.2 The Unit 1 Main Turbine is redesigned, replaced, and operates meeting the identified success criteria.

- Provide interim effectiveness review to CARB identifying the results of the third party review of new turbine design 30 days prior to installation.
- Provide interim effectiveness review to CARB identifying the results of the installation testing 60 days after the replacement.
- Provide interim effectiveness review to CARB 9 months after installation identifying the results of online performance monitoring.

Return to CARB to present interim effectiveness reviews detailing the results of the blade inspection 90 days after the end of the outages. If no defects are found then the effectiveness reviews will return at 1R, 2R, and 4R, with 4R being the final effectiveness review.

ER 00838732-29

Owner: ESY, Due: 01/28/17

This action and all sub assignments will be Management Excepted in accordance with PMP-7030-CAP-002. Sub-assignments are created for each interim effectiveness review.

**6.0 ATTACHMENTS**

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## UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.1

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### 6.1 PRE-ANALYSIS

1. **CR Number:** 00838732

2. **Event Description:**

Unit 1 main turbine generator was manually tripped on September 20, 2008 @ 20:05 due to high vibration in conjunction with turbine generator related fire detection control room alarm annunciation. The hydrogen fire required entry into the Emergency Plan (Unusual Event). No abnormal system parameter indications were noted prior to the event.

3. **Problem Statement:**

The Unit 1 reactor was manually tripped following elevated vibrations from the Main Turbine and a reported hydrogen fire from the Main Generator.

4. **Prompt and Interim Actions:**

Unit 1 main turbine generator tripped on September 20, 2008 @ 20:05 due to high vibration in conjunction with turbine generator related fire detection control room alarm annunciation.

A Notification of Unusual Event (NUE) was declared at 20:18 and the fire reported extinguished at 20:28. This event was reported under three conditions:

- 1) Activation of the site Emergency Plan,
- 2) 10CFR50.72 (b)(2)(iv)(B) for actuation of the Reactor Protection System (4 hour report), and
- 3) 10CFR50.72 (b)(3)(iv)(A) for automatic actuation of the Auxiliary Feedwater system (8 hour report).

NRC Event Notification number 44507 was assigned for all three reportable conditions. The prompt reporting for the 4 and 8 hour reports was completed September 20, 2008 @ 23:47.

Main condenser vacuum was broken to stop main turbine rotation due to excessive vibration. The Steam Generator Stop Valves (SGSVs) were also manually closed to arrest Unit 1 post trip Reactor Coolant System cooldown.

Isolation of steam flow to the main condenser was performed in accordance with 1-OHP-4023-ES-0.1, Reactor Trip Response, Step 1 Response Not Obtained (RNO). Isolation of steam flow removed the main condenser as the primary heat sink and RCS Temperature control was established on the Steam Generator Power Operated relief Valves (PORVs).

Failure Investigation Process (FIP) Team is currently in-progress.

5. **Scope of Evaluation:**

This evaluation will use the Failure Investigation Process to establish the reason for the main turbine generator failure. From the established equipment failure mode the organizational and programmatic barriers will be assessed to determine the root cause.

- Structure Tools – Fault Tree

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.1**

- Analysis Tools – Support Refute including equipment forensic analysis, Barrier Analysis and Safety Culture
- QV&V Tool - Why Staircase

The organizational responses to the turbine event and the Fire Protection Equipment failure are outside the scope of this root cause. Refer to CR 00838833 (East Diesel Driven Fire Pump Damage), CR 00838929(Ruptured Fire Header), CR 00838930(North Fire water Tank Emptied) and the reactor trip review for details outside the scope of this Root Cause Evaluation.

**6. Evaluation Team:**

Management Sponsor:	Ray Hruby (MGRL)	Ext 5184
Root Cause Evaluator:	James Nadeau (NFG)	Ext 5132
LOD Mentor:	Lance Germani (LOD)	Ext 2451
Team Member:	Ray Waldo (PII Consultant)	
Team Member:	Gary Proulx (ESY)	Ext 2764
Team member:	Dan Garner (PRJ)	Ext 5624
Team Member:	John Hirsch (PII Consultant)	
Team Member	Sam Dasgupta (Progress Energy)	

**7. Schedule:**

Note – The FIP team will establish the equipment initiating event and turnover this information to the Root Cause Team. The Root Cause Team will start with the equipment initiating event and will conduct additional forensics and programmatic investigations necessary to determine cause of the failure. The Root Cause Team will be sequestered and will conduct the investigation confidentially. The Team Compliment will be reassessed upon determination of the equipment initiating event. The pre-analysis schedule will be represented to Management Screening Committee to establish the due dates once the schedule to complete the fault tree and support refute is determined.

Present Pre-Analysis to Management Screening Committee (MSC):	9/30/08
Establish Schedule to complete Fault Tree and Support Refute (T=0):	10/24/08
FIP Team Turns over to Root Cause Team - Investigation initiated:	
T=0	11/17/08
Causal Analysis:	T+21 days
Preliminary Failure Diagnostics from PII:	12/17/08
Draft Internal Root Cause Report:	12/19/08
Report Review/Revision Cycle:	
Final Draft of Failure Diagnostics from PII:	02/06/09
Report Approval Ready for Corrective Action Review Board (CARB):	03/13/09

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.2**

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**6.2 TRIP REPORT ABSTRACT, SEPTEMBER 20, 2008**

On September 20, 2008 at 20:05 the DC Cook Unit 1 Reactor was manually tripped due to high main turbine generator vibration. A hydrogen fire occurred in the Main Generator high voltage bushing area below the Main Generator. Based on visual inspection of the inside of the high voltage bushing box, the fire origin was either a failed gasket or seal at the phase 1 bushing. A Notification of Unusual Event was subsequently declared at 20:18 due to Event classifications H-4, Fire within the Protected Area Not Extinguished within 15 minutes and H-5, Toxic or Flammable Gas Release Affecting Plant Operation. The Unit 1 Main Generator Fire was reported extinguished on September 20, 2008 at 20:28.

This event was reported to the Nuclear Regulatory Commission as a four hour report required by 10CFR50.72(b)(2)(iv)(B) due to the Reactor Protection System actuation and as an eight hour report required by 10CFR50.72(b)(3)(iv)(A) for the automatic actuation of the Auxiliary Feedwater system. The Notification of Unusual Event was reported separately. No radiological release resulted from this event. See Event notification number 44507 for details.

Automatic control systems functioned as expected with two notable exceptions: the Main Generator separation from the GRID occurred 346 milliseconds following the Main Turbine trip and Main Steam to 125 psig Aux Steam reducing valve, 1-SRV-402, did not control 125 psig Auxiliary Steam header pressure as expected. All control rods fully inserted on the manual Reactor trip. The Main Turbine automatically tripped as designed in response to the manual Reactor trip. The Turbine Driven and both Motor Driven Auxiliary Feedwater pumps automatically started and fed all four Steam Generators as designed. Main Condenser Vacuum was promptly broken by the operating crew to slow the Main Turbine and mitigate the high turbine vibration. The main generator tripped automatically after the turbine trip due to actuation of the Generator Overall Differential Auxiliary relays. The immediate separation from the GRID was caused by vibration induced actuation of the Main Turbine Exhaust High-High Temperature switch input to Main Turbine Valve Trip relay 33-VED. Failure of 1-SRV-402 to control Auxiliary steam pressure resulted in the observed Reactor Coolant System (RCS) cooldown.

Tave dropped to approximately 536°F immediately following the Reactor trip. This is an expected response for Unit 1 because Unit 1 Programmed Tave is only 556°F at full power. Tave recovered to approximately 538°F then lowered steadily to approximately 528°F over the next 40 minutes. The Steam Generator Stop Valves were manually closed to arrest plant cooldown. Unit 1 Tave subsequently recovered reaching 541°F in approximately 20 minutes.

Discussion with the Shift Manager, Unit 1 and Unit 2 Unit Supervisors revealed two reasons for the Reactor Coolant System Tave reaching to 528°F.

- The first reason was that auxiliary feed water flow reduction was performed in two steps. At four minutes after the trip, (estimated time to reach step 4 of E-0), the BOP reduced aux feed flow from approximately 130 kph/SG to 90 kph/SG (Rtime data). About five minutes later, flow was again reduced to approximately 65 kph/SG, where it remained for the next 39 minutes. This delay in Auxiliary Feedwater flow reduction contributed to the Unit 1 RCS cooldown, but even if pursued more aggressively, would not have been sufficient to prevent

## **UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.2**

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Main Steam Line isolation to arrest the RCS cooldown. ESAT 08287018 was written to provide additional Training emphasis on post trip control of the Auxiliary Feedwater system.

- The second reason was the transfer of Auxiliary Steam loads from Unit 1 to Unit 2. Unit 1 was carrying the Auxiliary Steam header when the trip occurred. The Operating Crews in both units indicated that the attempted transfer of Auxiliary Steam occurred 15 to 20 minutes following the Unit 1 trip. This delayed response was due to the Unit 2 Operating crew responding to the secondary plant transient caused by simultaneous start of the standby Hotwell, Condensate Booster and Turbine Auxiliary Cooling Water pumps and performing the prompt notifications required for the Notification of Unusual Event. Vibration actuation of the associated pump auto start pressure switches is the suspected cause of the unexpected automatic starts of the standby secondary pumps and extraction steam isolations.

Main Steam to 125 psig Aux Steam reducing valve, 1-SRV-402 was in service at the time of the Unit 1 trip. 1-SRV-402 valve position had been logged weekly by the Thermal Performance Engineer as 75% open. Auxiliary Steam was transferred to Unit 1 on 5/16/08. The position of 1-SRV-402 recorded by the Thermal Performance Engineer had not changed in four months. Local inspection of 1-SRV-402 indicated some shaft scoring on one side of the positioner shaft, at the packing gland. The consistent lack of any noted change in valve position, the shaft scoring and the Auxiliary Steam response following the Unit 1 trip on 9/20/08 indicates 1-SRV-402 was mechanically bound during the Unit 1 trip response.

Based on PPC trend review of the Unit 1 RCS Tave response, the cooldown continued unabated until the Main Steam Lines were isolated approximately 40 minutes following the Reactor trip. No rise in the Unit 2 Plant Process computer (PPC) Thermal Power trend occurred until the Unit 1 Main Steam lines were isolated. This indicates that Auxiliary Steam was not actually transferred to Unit 2 until the Unit 1 Steam Generator Stop Valves (SGSVs) were closed. Unit 1 Tave recovered promptly following steam line isolation. Tave stabilized consistent with the Steam Generator PORV settings. This indicates the cause of Unit 1 excess RCS cooldown was the Auxiliary Steam system.

The magnitude of the RCS cooldown contribution from Auxiliary Steam is also a concern. Unit 1 was carrying Steam Jet Air Ejectors for both Units and Steam Seals for Unit 1 following the trip. Based on visual report of personnel responding to the Technical Support Center (TSC) at least one of the Unit 1 50 psig Aux Steam Header 75 psig Safety Valves (1-SV-126A or 1-SV-126B) lifted during the Unit 1 transient and remained open until the Unit 1 SGSVs were closed. Based on visual report from the Unit 1 Balance of Plant (BOP) operator who performed the controller manipulations to swap 125 psig Auxiliary Steam to Unit 2, header pressure was approximately 175 psig. This indicates at least one 125 psig Aux Steam header 180 psig Safety Valves (1-SV-46 or 2-SV-46) was lifting during the Auxiliary Steam controller manipulations. 125 psig Aux Steam header 180 psig Safety Valve, 2-SV-46 was locally confirmed to be lifting following the Unit 2 power reduction after assuming the Auxiliary Steam loads when Unit 1 main Steam was isolated (See Unit 2 21:20 Control Room log entry). The combination of existing Auxiliary Steam loads and the transient response lifting of at least one 50 psig Aux Steam Header 75 psig Safety Valve and at least

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one 125 psig Aux Steam header 180 psig Safety Valve provides sufficient steam load to account for the Unit 1 post trip RCS cooldown.

Unit 1 Main Steam pressure rose rapidly from approximately 670 psig to 900 psig during the initial trip transient. It is suspected that 1-SRV-402 failed to respond to changing Unit 1 Main Steam supply pressure during the transient. This changed the differential pressure across 1-SRV-402 by 230 psid and is suspected of overpressurizing the Unit 1 125 psig Auxiliary Steam system and lifting 2-SV-46. There are no PPC monitoring points for the Auxiliary Steam system and no empirical data exists to verify specific Auxiliary Steam System component response. The supporting facts are derived from reports and interview statements from plant personnel on site during the post trip response. A similar binding issue was noted in December 2006 when 2-SRV-402 failed to respond while attempting to place 2-SRV-400 in service. See WR 06354085 for details.

The 50 psig Auxiliary Steam header was also overpressurized resulting in lifting of at least one 75 psig safety valve. The suspected cause is slow response of 50 psig Aux Steam Header Pressure Reducing Valve, 1-ARV-500 to rapidly rising Main Steam system pressure following the Unit 1 trip. Lifting of these Auxiliary Steam system safety valves in conjunction with existing Unit 1 sealing steam and both Units Steam Jet Air Ejector jet steam supply dominated the Unit1 RCS cooldown until Main Steam was isolated.

There is no current PM task for internal inspection and repair/rebuild of Main Steam to 125 psig Aux Steam reducing valves, 1(2)-SRV-402. A PM to refurbish the actuators and repack the valves (MWO 55265017) exists with an 18 year periodicity. Another PM to perform actuator setup and calibration (MWO 55277614) currently exists with a four year periodicity. 1-SRV-402 actuator setup and calibration was last performed on 11/16/2005. No work was performed on 1-SRV-402 because the as found test was satisfactory. 1-SRV-402 was disassembled for internal inspection on 10/23/2000. This inspection noted pitting of the valve seating surface and nicks in the valve cage assembly. The internal components of 1-SRV-402 were subsequently replaced. No as left testing was documented. ESATs 08282083 and 08282084 were written to perform AOV diagnostic testing on 1-SRV-402 and internal inspection as necessary to determine and correct the cause of the valve binding experienced during the Unit 1 post trip response.

- The 250 VDC pump bus control power circuit breaker, 1-CRCD-7, tripped during plant trip response (see WR 06364959). This prevented isolation of numerous Feedwater Heater and Moisture Separator extraction line drains. This contribution to the Unit 1 RCS cooldown is limited due to isolation of these drains from the Unit 1 Main Steam System following the Unit 1 turbine trip. The East and West Bypass Header Steam Lead Drain valves (1-DRV-403 and 1-DRV-404) are large, 2 ½ inch drains which have contributed significantly to post trip RCS cooldown in the past. Turbine Bypass Header Drain Valves pneumatic selector, 1-AT-17, normal position was changed to prevent automatic opening of the bypass header drains following a Turbine trip to prevent unnecessary main steam line isolation due to excess post trip RCS cooldown. 1-AT-17 was closed during the Unit 1 trip on 9-20-08 and remained closed during the trip response. Plant Cooldown from Hot Standby to Cold Shutdown, 1-OHP-4021-001-004, step 4.46 opens 1-DRV-403 and 1-DRV-404. This procedure step was

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performed well after the Unit 1 Main steam lines were isolated and had no impact on Unit post trip RCS cooldown. Operation of 1-DRV-403 and 1-DRV-404 was verified following the Unit 1 cooldown. The operation of 1-DRV-403 and 1-DRV-404 validated integrity of the associated control air piping and eliminated 1-DRV-403 and 1-DRV-404 as a potential source of the excess RCS cooldown.

Unit 1 was stabilized in Mode 3. The main condenser was isolated as the primary heat sink. This was inevitable because main condenser vacuum was deliberately broken to stop the Unit 1 Main Turbine Generator to mitigate the high vibration condition. Steam Generator Power Operated Relief Valves removed core decay heat in automatic control after breaking main condenser vacuum and isolating the Main Steam lines. Shutdown Margin was satisfactorily verified. Plant cooldown was commenced at 22:50 and the RCS was subsequently cooled down to Mode 5, Cold Shutdown. The High Main Turbine vibration and Main Generator fire is being investigated under root cause AR 838732.

The Fire Suppression Water System was actuated during fire suppression of the Unit 1 Main Generator. An underground Fire Suppression Water System distribution pipe ruptured during response to the Unit 1 Main Generator fire. Approximately 80 minutes after the trip/fire, the in service (North) Fire Water Storage Tank was empty. All three fire water pumps (East and West diesel driven and the motor driven) were stopped due to loss of suction supply water. The North Fire Water Storage Tank and all three fire water pumps were declared INOPERABLE. Approximately ninety minutes later the backup fire protection water source from Livingston Road was established as required by TRM 8.7.5, Condition C. The South Fire Water Storage Tank was placed in service and the Fire Protection Pegging pump was started to pressurize the Fire Protection Water distribution header. The East Diesel Driven Fire Pump was damaged during the fire response and subsequently declared INOPERABLE as required under TRM 8.7.5, Condition A. The root cause of the distribution pipe rupture is being investigated under AR 838930.

The Turbine Building is separated from the Screen House and Auxiliary Buildings by seismic spaces or physical gaps between the buildings. The Main Turbine supports and Turbine Room foundation are Seismic Class I structures. The remainder of the Turbine Room structure is a Seismic Class III structure. The Auxiliary Feedwater system which is housed in the Turbine Room 591' elevation is Seismic Class I. The Screen House Essential Service Water enclosures and the Auxiliary Building are Seismic Class I structures (Reference USAR section 2.9.2). These structures, Systems and components are not seismically threatened by the Unit 1 Turbine Generator vibration event of 9-20-08 because the structures are seismically separated from the affected structure or designed as Seismic Class I and capable of withstanding this event.

Piping and electrical walkdowns are being performed by separate teams. This includes structural design engineers, System Engineers and American Electric Power (AEP Corporate) Structural Engineers. The walkdown teams preliminary results indicate flexure of the Turbine Building foundation, but no indications of damage to the structure as a result of the Unit 1 Turbine event on 9-20-08. ESAT 08269048 was written to collect the results of the Turbine Building structural walkdown resulting from the Unit 1 Turbine Generator failure.

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Following the Unit 1 Main Turbine High Vibration trip the Unit Generator Overall Differential relays (87X-OA/87X1-OA/87X2-OA) tripped without the typical 30 second time delay from relays 62-GRTA and 62-GRTB (Generator Trip from Reactor System). There are three circuit inputs that directly actuate (trip) the Unit 1 Generator Overall Differential Auxiliary relays (87X-OA/87X1-OA/87X2-OA):

- Unit 1 Generator Overall Differential relays (87-OA phase 1, 2 and 3),
- Main Generator Output Breaker switchyard relay protection 551XK and 551XK1 from the 345 kV switchyard relay house,
- and Main Turbine Valve Trip relay 33- VED.

Two of these circuit inputs can be ruled out as cause of the Generator Overall Differential relay trip. 1-87-OA-1, 2, and 3 relays displayed no actuation targets and therefore was not the source of the Generator Unit Overall Differential Trip. Discussion with Fort Wayne-Transmission Dispatch Center determined no anomalies with 345 breakers kV K and K1 during the Unit 1 trip on 09/20/08. No targets were found on any relays in the Cook Plant 345 kV switchyard relay house. This eliminates Unit 1 Generator Overall Differential relays (87-OA phase 1, 2 and 3) and the Main Generator Output Breaker switchyard relay protection 551XK and 551XK1 as potential causes of the post trip response of Unit 1 Generator Overall Differential Auxiliary relays (87X-OA/87X1-OA/87X2-OA). By process of elimination, this leaves Main Turbine Valve Trip relay 33- VED as the direct actuation for Unit 1 Generator Overall Differential Auxiliary relays (87X-OA/87X1-OA/87X2-OA).

Four Main Generator relays were noted tripped during Unit 1 post trip relay evaluation:

- Generator Overcurrent Auxiliary relay, 151-GS
- Generator Field Ground Detecting relay, 64-GF
- Turbine Valve Trip relay, T-1
- Generator Field Breaker(s) Tripped relay, T-3.

Only one of these relay trip indications (Turbine Valve Trip relay, T-1/ 33-VED actuation) results in actuation of the Unit 1 Generator Overall Differential Auxiliary relays (87X-OA/87X1-OA/87X2-OA). Generator Overcurrent Auxiliary relay, 151-GS is only active prior to closing Generator output breakers. Generator Field Ground Detecting relay, 64-GF only produces field ground alarms, Generator Field Breaker(s) Tripped relay, T-3 results from tripping either or both the Unit and Overall Differential Auxiliary relays.

There are three basic circuit flowpaths controlling actuation of the 33-VED relay actuation of the Unit 1 Generator Overall Differential 87X-OA trip. Refer to OP-1- 98021-50, Gen & Transformer Differential Elementary for details supporting the following discussion.

During a normal Reactor Trip, breaker contacts 52X-RTTA/B open to start time delay relays 62-GRTA and 62-GRTB. After 30 seconds, contacts close energizing relay 33-VED and tripping Unit 1 Generator Overall Differential relays 87X-OA/87X1-OA/87X2-OA. Actuating relay 33-VED trips the Main Generator Output Breakers (345 kV K & K1), the Exciter Field Breakers, Unit differential relays 87X-U/87X1-U/87X2-U and initiates fast transfer for the 4 kV electrical busses from the Unit Auxiliary Transformers (UATs) to the Reserve Auxiliary Transformers (RATs). This is the normal mechanism for post trip GRID separation.

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A second flowpath for actuating relay 33-VED and tripping the Generator Overall Differential Auxiliary relays exists if the Reactor trip Breaker(s) fail to open when the Main Turbine Stop valves, and either the Intermediate (Reheat) Stop or Intercept valves in each steam line indicate closed. This electrical flowpath bypasses 30 second time delay relay 62-GRTA and 62-GRTB contacts and immediately energizes relay 33-VED to backup the Main Turbine trip in the event of an Anticipated Transient Without Scram (ATWS).

A third circuit exists for actuation of 33-VED and the Generator Overall Differential Auxiliary relays. This circuit requires the Main Turbine Stop Valves to be closed, either or both Main Generator output breakers 345 kV K/K1 to be closed, and any one of the six Main Turbine Exhaust Hood High-High Temperature switches actuated (indicating >225°F) to actuate relay 33-VED. In this case 33-VED is actuated without any time delay. This is a form of anti-motoring protection designed to prevent overheating of the Main Turbine last stage blades.

Based upon the high vibration levels produced prior to and immediately following the Unit 1 trip on 9/20/08, it is highly likely that at least one of the Exhaust Hood Temperature Switches operated. These temperature switches function by means of differential fluid expansion to operate a snap-lock. Two temperature switches are mounted on each low pressure turbine exhaust hood (one on each Low Pressure Turbine end). The mechanical forces due to turbine vibration during the event were more than adequate to actuate these snap-lock switches, close its contact and energize relay 33-VED.

Local measurements were performed to confirm the contact switch positions for the six CTA Hood Temperature Alarm switches. Five of the six Temperature switch contact sets (1-CTA-110, 1-CTA-111, 1-CTA-121, 1-CTA-130, and 1-CTA-131) were found electrically closed. Only 1-CTA-120 was in the open electrical state. This explains why Generator Unit Overall Differential Trip which occurred without the normal 30 second time delay during the 9/20/08 Reactor Trip Response.

The Digital Control System Turbine Supervisory Instrumentation (TSI) annunciators (1-TTC-25, 26, and 27; ml-ALM42 Drops 124-129) do not receive their input from Main Turbine Exhaust Hood High High Temperature switches (1-CTA-110, 1-CTA-111, 1-CTA-120, 1-CTA-121, 1-CTA-130, and 1-CTA-131). These DSC-TSI inputs are provided by separate RTDs on the Main Turbine Exhaust Hood. Some of these RTDs were discovered broken off during local inspection. ESAT 08273041 was written to document the engineering evaluation of the unexpected post trip response of the Generator Overall Differential Auxiliary relays and create WRs to repair/replace failed Temperature sensors. Review of the Post Trip Exhaust Hood Temperature response Digital Controls System (DCS) trend showed only Low Pressure Turbine C had exceeded the 225°F trip setpoint. This Unit 1 Main Turbine Exhaust Hood Temperature trend indicated that the High-High Exhaust Hood Temperature condition was not reached for approximately one minute and forty seconds following the manual reactor trip.

Unit 1 Generator Overall Differential relays actuated approximately one second following the Main Turbine Trip. Since the Main turbine was tripped, separated from the GRID electrically

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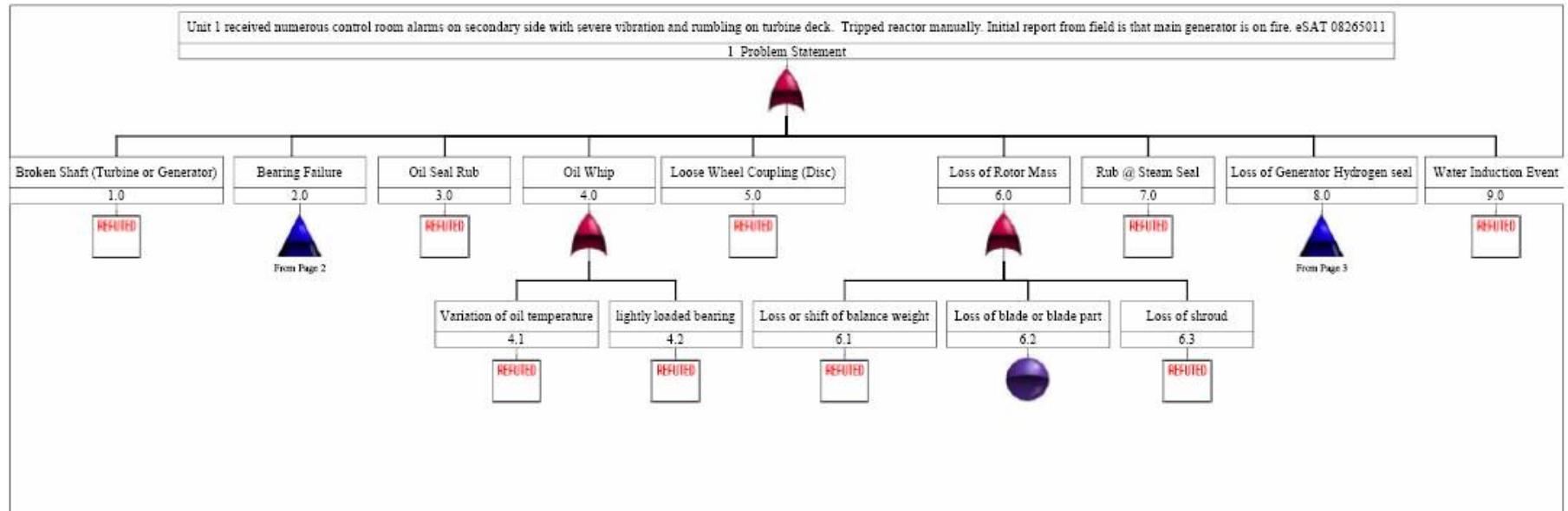
**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.2**

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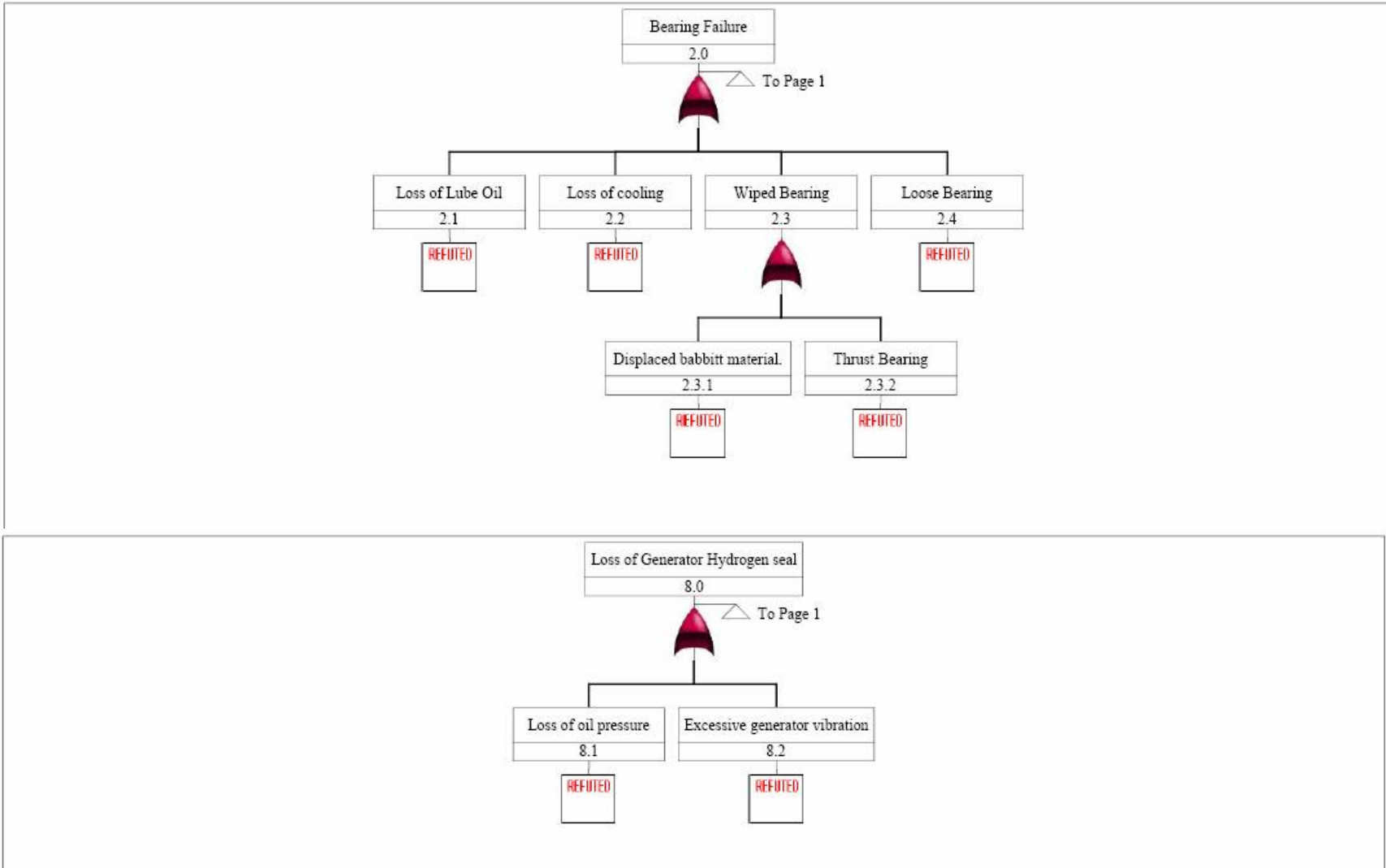
and slowed by breaking condenser vacuum within one minute of the Reactor trip, it is unlikely that the actual Main Turbine Exhaust Hood Temperature reached 225°F.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.3**

**6.3 FIP FAILURE MODE CHART**



**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.3**



**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.4**

**6.4 FIP SUPPORT REFUTE MATRIX**

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Possible Failure Cause		Supporting/Refuting Information	Actions Required
1 Problem	Unit 1 received numerous control room alarms on secondary side with severe vibration and rumbling on turbine deck. Tripped reactor manually. Initial report from field is that main generator is on fire. eSAT 08265011	MISC	NONE
2.0	Bearing Failure	REFUTE:	NONE
6.0	Loss of Rotor Mass	SUPPORT: Sudden change in vibration spectra	NONE
3.0	Oil Seal Rub	REFUTE: There was no leakage identified coming from the seals during inspections. Vacuum was within normal parameters and stable.	NONE
4.0	Oil Whip	REFUTE: Vibration change was sudden and large. Oil whip would be an vibration that would raise over time.	NONE
2.1	Loss of Lube Oil	REFUTE: Continuous pressure and flow at the sight glass prior to failure.	NONE
2.2	Loss of cooling	REFUTE: Bearing Temperatures were normal until Trip.	NONE
4.1	Variation of oil temperature	REFUTE: No noted changes in oil temperature	NONE
4.2	lightly loaded bearing	REFUTE: No vibration data noted on bearing 5/6, sudden change in vibration spectra prior to the event.	NONE
1.0	Broken Shaft (Turbine or Generator)	REFUTE: Sudden vibration change. Both Turbine and Generator Shafts were inspected and found intact.	NONE
5.0	Loose Wheel Coupling (Disc)	REFUTE: Sudden Vibration Change. Wheel couplings are shrunk on the shaft. Inlet wheels also have axial lock pins. Could not move without very high heat.	NONE
7.0	Rub @ Steam Seal	REFUTE: No leading vibration indications. Would not be a huge spike in vibrations.	NONE
2.3.1	Displaced babbit material.	REFUTE: No Gap Voltage Changes prior to the event. SUPPORT: Change in metal temperatures on bearing #4.	NONE

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.4**

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Possible Failure Cause	Supporting/Refuting Information	Actions Required
2.3.2 Thrust Bearing	REFUTE: Sudden change in vibration data. No thrust bearing alarm or trip prior to event.	NONE
8.0 Loss of Generator Hydrogen seal	REFUTE: Loss of hydrogen seal would not cause turbine rotor to move. Any vibration caused by this would have been seen at the generator first and not LP B.	NONE
8.1 Loss of oil pressure	REFUTE: Oil pressure remained constant until event.	NONE
8.2 Excessive generator vibration	REFUTE: J. McClellan to provide information to support or REFUTE: generator negative sequencing. At time of event was well under limits. 1.8% was worst case grid instability. 5% is limit. Support: OE from ANO-1 in 2001 showed event where excessive turbine vibration caused shearing of H2 piping.	NONE
9.0 Water Induction Event	REFUTE: No Heater HI / HI-HI or extraction steam drip pot alarms	NONE
2.3 Wiped Bearing	REFUTE: Bearing Temperatures were steady until the event.	NONE
2.4 Loose Bearing	REFUTE: constant bearing metal temperature. Loose bearing would show with higher than 1X frequency. Only 1X vibration frequency seen.	NONE
6.1 Loss or shift of balance weight	REFUTE: Weight were in there relative locations on END plate. Midspan a few weights were missing that looked like they were knocked off during event. Not enough to cause the amount of vibrations seen.	NONE
6.2 Loss of blade or blade part	SUPPORT: 4 blades lost on turbine end of LP B and 1 blade on turbine end of LP C.	Complete PII Failure Diagnostics PII 2/19/09
6.3 Loss of shroud	REFUTE: Shrouds were all intact	NONE

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.5**

**6.5 DATA SHEET 2 - EQUIPMENT FAILURE EVALUATION CHECKLIST**

Address Items 1-11 on the form by answering the questions and checking either YES, NO, or N/A in the associated blocks. The completed checklist is expected to be attached to all Root Cause, Equipment apparent cause and In-Depth apparent cause evaluation analyzing equipment failures.

CR No. 00838732					
Item No.	Question for Review	Response			Information included in Report (Initial)
		Yes	No	N/A	
1	Had any associated PMs been missed or otherwise delayed?		N		JJN
2	Is there any aspect of the PM Program that appears to be inadequate?		N		JJN
3	Are there deficiencies in the performance of past maintenance?		N		JJN
4	Are there system, component, or program monitoring deficiencies?		N		JJN
5	Does any industry, vendor or Internal OE exist that is applicable to this component?	Y			JJN
6	Are there any previous corrective actions that appear to have been inadequate?		N		JJN
7	Are there deficiencies in current operating procedures or practices?		N		JJN
8	Are there deficiencies in current maintenance practices/behaviors or in associated training?		N		JJN
9	Does there appear to be any deficiency in design?	Y			JJN
10	Is there any concern with quality of parts, shipping, or handling?	Y			JJN
11	Is the Zero Tolerance classification of the component appropriate?	Y			JJN

Conclusion: The Root Cause Evaluation identified concerns with the Main Turbine design resulting in a high stress conditions in the L-0 blades. The Zero Tolerance classification does not allow any failures. The Maintenance Rule criterion is monitored at the Plant Performance level. These classifications are appropriate.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.6**

**6.6 BARRIER ANALYSIS**

<b>Barrier</b>	<b>What is in effect?</b>	<b>How did barrier fail or work?</b>	<b>Possible Solutions</b>	<b>Cause Relationship</b>
<b>Design - Siemens</b>	<ul style="list-style-type: none"> <li>The LP turbine retrofit was designed in accordance with the Siemens design process. Three L-0 blades failed in HCF due to blade-rotor system design that didn't account fully for normal stressors.</li> </ul>	<ul style="list-style-type: none"> <li>The Siemens design process did not identify design issue that caused blade failure.</li> </ul>	Prototype testing of original or modified blades. Increased frequency of in-service testing. Third party evaluation of design or testing.	<b>Causal</b>
<b>Design - General Electric</b>	<ul style="list-style-type: none"> <li>Siemens needed design information for torsional frequency and bearing stiffness. Torsional data was GE proprietary information that was not provided. Siemens needed to make assumptions and CNP/S&amp;L need to perform structural calculations.</li> </ul>	<ul style="list-style-type: none"> <li>Acceptability was validated by on-line testing of the GE unit and the Siemens Unit.</li> <li>Did not identify nor is it related to design issue that caused blade failure.</li> </ul>	None	None
<b>Design - CNP/S&amp;L</b>  EMOD 46925 'Unit 1 Low Pressure Turbine Upgrade' completed in accordance with PMP-5040-MOD-007.	<ul style="list-style-type: none"> <li>EMOD 46925 – L-0 Blades were identified as a first of a kind installation that needed additional online testing. In both modification description and in the risk review. S&amp;L performed design verification by design review method.</li> <li>AEP Turbine Section reviewed modification package. AEP Turbine Section did not actually do a design validation (not qualified to any CNP procedures.)</li> </ul>	<ul style="list-style-type: none"> <li>Identified risk areas including torsional vibrations and L-0 blade design. Detection (testing) actions were specified and implemented.</li> <li>Did not identify nor is it related to design issue that caused blade failure.</li> </ul>	None	None
FCN-46925-04 – add mass to L-0 blades to correct torsional frequency, completed in accordance with PMP-5040-MOD-007.	<ul style="list-style-type: none"> <li>Cracking discovered at blade tips indicate that failure would have eventually occurred even if L-0 blades had not failed at roots. Cracking at the Tips is indicative of aero-elastic bending.</li> </ul>	<ul style="list-style-type: none"> <li>L-0 blade failure at root is indicative of high stress. The aero-elastic bending may have added additional stress at the root.</li> </ul>	Third party evaluation of design using alternate calculations or methodology to by technically competent group.	None Area for Improvement
CNP Review of Calculation SD-060310-002 'Vibration Analysis of Unit 1 Turbine Generator Pedestal Structure	<ul style="list-style-type: none"> <li>Concrete structure was analyzed.</li> <li>The steel support structure for the bearings (pedestal) was not analyzed. Siemens reviewed calculation and determined it was acceptable for their purpose.</li> </ul>	CR 00827288 identified a 'Lack of Ownership in re-design of U1 Low Pressure Turbines'  <ul style="list-style-type: none"> <li>Design Engineering did not play a significant role in the design activities. It is believed that a design weakness in the bearing modifications performed as part</li> </ul>	Corrective Actions Taken are established in CR 00827288.	None

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.6**

Barrier	What is in effect?	How did barrier fail or work?	Possible Solutions	Cause Relationship
		<p>of 1-MOD-40012 may have contributed to the high bearing vibration condition that led to the February 2008 shutdown.</p> <ul style="list-style-type: none"> <li>This was a weakened barrier that contributed to the February 2008 shutdown, but no relationship to the cause of the turbine failure was established.</li> </ul>		
<p><b>Sign/Warning</b>  <b>Vibration Monitoring and Inspections</b></p> <ul style="list-style-type: none"> <li>Radial – Operated within specification with exception of February 2008 and September 2008 trips.</li> <li>Axial – Not measured</li> <li>Torsional Testing completed Nov. 2006</li> <li>Blades – BSSM Testing Nov. 2006</li> <li>All 300 L-0 blades visually inspected and the 100 LP B Blade Tips Dye Penetrant Test (PT) performed on welded plates in April 2008.</li> <li>Rotor-Out inspection.</li> </ul>	<ul style="list-style-type: none"> <li>Radial – No warning of vibrations rising in September 2008.</li> <li>Torsional Testing was acceptable in initial startup testing in 2006 and was not monitored since.</li> <li>Blades – BSSM Testing was a one time test in Nov. 2006. Did not detect issues causing L-0 blade failures.</li> <li>Blade VT and PT in April 2006 met acceptance criteria.</li> <li>Rotor-Out inspection frequency was changed from max 6 year for GE rotor to 10 year frequency for Siemens rotor. A Rotor-Out inspection was not performed in April 2008 refueling outage because the Siemens design established a 10 year frequency per contract C-11486.</li> </ul>	<ul style="list-style-type: none"> <li>None of the Vibration Monitoring or Inspections scheduled would be expected to provide early detections of the High Frequency Fatigue failures identified with the exception of the Rotor-Out Inspection. The Rotor-Out Inspection includes a Magnetic Particle Test (MT) which could have detected blade failures in progress.</li> </ul> <p>This barrier failed because the monitoring and testing prescribed for the new turbines could not provide early warning of the failures.</p>	<p>Continuous on-line torsional testing.</p> <p>On-line Blade Monitoring.</p> <p>Re-designed L-0 Blades or Rotor</p> <p>Increased Inspection Frequency for new designs.</p>	<p>None</p> <p>Actions proposed exceed expected or vendor recommendations.</p>
<p><b>Sign/Warning</b>  <b>Lube Oil</b></p> <ul style="list-style-type: none"> <li>Temperature</li> <li>Chemical Analysis</li> <li>Filter</li> </ul>	<ul style="list-style-type: none"> <li>Lube Oil Temperature, Chemical Analysis and Filter Monitoring were maintained in specification through out operational history.</li> </ul>	<ul style="list-style-type: none"> <li>Signs of torsional or resonance induced vibration would not be expected to be seen in these analyses.</li> </ul>	<p>None</p>	<p>None</p>
<p><b>Procedure</b>  <b>Initial Risk Analysis per PMP-5040-MOD-007</b></p>	<ul style="list-style-type: none"> <li>EMOD 46925 – L-0 Blades were identified as a first of a kind installation that needed additional online testing. First of a kind L-0 blades were identified in both the modification description and in the risk review.</li> </ul>	<ul style="list-style-type: none"> <li>Identified risk areas including torsional vibrations and L-0 blade design. Industry accepted detections (testing) actions were specified and implemented. This included torsional and BSSM testing.</li> </ul>	<p>None</p>	<p>None</p>

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.6**

<b>Barrier</b>	<b>What is in effect?</b>	<b>How did barrier fail or work?</b>	<b>Possible Solutions</b>	<b>Cause Relationship</b>
<b>Procedure</b> Design Information Transmittal	<ul style="list-style-type: none"> <li>Not used or needed.</li> </ul>	<ul style="list-style-type: none"> <li>Not needed</li> </ul>	None	None
<b>Procedure</b> Calculations per 12-EHP-5040-DES-003	<ul style="list-style-type: none"> <li>Calculations of pedestal (metal structure supporting bearings) frequency were not conducted.</li> </ul>	<ul style="list-style-type: none"> <li>May have contributed to bearing # 5 and #6 light loading. This is a separate condition adverse to quality which was determined not to be a contributor to this event.</li> </ul>	Actions are specified in CR 00825512 and WO 55323969-01	None
<b>Procedure</b> Risk Analysis for FCN  12-EHP-2291-RIS-001 and PMP-5040-MOD-007 or PMP-2291-WAR-001.	<ul style="list-style-type: none"> <li>Risk Review not performed using any of the available procedures for the FCN to modify the L-0 blades by adding weights. Options, risks and control measures that Siemens proposed were provided in Siemens presentation. Acceptance of L-0 blade modification and expected control measures were documented in CC 2006-984</li> </ul>	<ul style="list-style-type: none"> <li>This barrier was not used or required at the time of the FCN. The modification proposed by Siemens was scrutinized fully by CNP and elevated to Senior Management. Formal use of the risk process would likely not have impacted the decisions because the risk process concepts were applied.</li> </ul>	None	None
<b>Procedure</b> Installation and testing  Work Package TG 6427.00	<ul style="list-style-type: none"> <li>Siemens installed the L-0 Blades on the turbine after the tip modification in different locations than originally installed during the 120% over speed test in the bunker. Their-installation procedure did not include a check of critical root attachment clearances.</li> </ul>	<ul style="list-style-type: none"> <li>Gaps are not verified during installation because Siemens has manufacturing data that the blades and rotors meet specification.</li> <li>Gaps in the L-0 blade root attachments (within manufactures tolerances) were identified in the PII report as a likely contributor to increased stress in the root location.</li> </ul>	Third Party Design Validation	Contributor
	<ul style="list-style-type: none"> <li>Torsional Test of GE Train – S32M7/2005/1044 (7/18/2005) Rev. 1</li> <li>Torsional Studies 9/11/06 - S32M7/2005/1044 (7/18/2005) Rev. 2</li> </ul>	<ul style="list-style-type: none"> <li>Did not detect nor is it expected to detect design issue that caused blade failure. Test met acceptance criteria</li> </ul>	None	None
	<ul style="list-style-type: none"> <li>Torsional Test of Siemens Train – P11M7-06-10822. Torsional Test November 2006 completed without strain gauges during load testing.</li> </ul>	<ul style="list-style-type: none"> <li>Did not detect nor is it expected to detect design issue that caused blade failure.</li> <li>Test met acceptance criteria as was determined to be valid.</li> </ul>	None	None
	<ul style="list-style-type: none"> <li>BSSM - Siemens Root Cause identified that testing was secured at 95% and did not envelop the operational conditions that Cook normally operated.</li> </ul>	<ul style="list-style-type: none"> <li>Did not detect nor was it expected to detect the failure mechanism. Test met acceptance criteria.</li> </ul>	Provide Online Monitoring	None
	<ul style="list-style-type: none"> <li>Radial Vibration</li> </ul>	<ul style="list-style-type: none"> <li>Did not detect nor was it expected to detect the failure mechanism. Test met acceptance criteria.</li> </ul>	None	None

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Barrier	What is in effect?	How did barrier fail or work?	Possible Solutions	Cause Relationship
	<ul style="list-style-type: none"> <li>• Post Modification Tests</li> </ul>	<ul style="list-style-type: none"> <li>• Did not detect nor was it expected to detect the failure mechanism. Test met acceptance criteria.</li> </ul>	None	None
<p><b>Procedure</b>                      Vendor Selection</p> <p>PMP-3140-CON-001                      DTG at time of selection. Turned into PMP-8100-PRJ-001 in June 2008                      PMP-1060-RPA-001</p>	<ul style="list-style-type: none"> <li>• Bid was accepted based on best net present value that met criteria. Resulted in acceptance of the Siemens/Westinghouse proposal.</li> <li>• Consideration of OEM proprietary information</li> <li>• Equipment performance history.</li> </ul>	<ul style="list-style-type: none"> <li>• PMP-3140-CON-001 does not contain criteria for evaluation bids that would have an influence on a newly designed equipment or replacement with non OEM equipment.</li> </ul>	Modify PMP-3140-CON-001.	None  Area for Improvement
<p><b>Procedure - Vendor Oversight</b></p> <p>Contracted Oversight (C-11486, Section 1 Technical)</p> <ul style="list-style-type: none"> <li>• 3.3.3 – Rotor Forging Evaluation</li> <li>• 3.3.4 – Stationary Components</li> <li>• 3.3.6 – Blades, Material, Dimensional, and frequency.</li> <li>• 3.5 – Materials</li> <li>• 3.7 – Cleaning Procedures</li> <li>• 3.8 – Protective Coatings</li> <li>• 3.10 – Packing and Shipping</li> <li>• 5.2 – Turbine (thermal) Performance Testing</li> <li>• 5.3 – Torsional Testing</li> <li>•</li> </ul>	<p>Contracted Oversight (C-11486, Section 1 Technical)</p> <ul style="list-style-type: none"> <li>• 3.3.3 – Rotor Forging Evaluation - Not performed and not related to equipment failure.</li> <li>• 3.3.4 – Stationary Components – Not performed and not related to the failure.</li> <li>• 3.3.6 – Blades, Material, Dimensional, and Frequency - Not performed. Siemens has data to support that the dimensions were within manufacturing tolerances.</li> <li>• 3.5 – Materials – Not performed. Materials were verified correct as part of the PII evaluation.</li> <li>• 3.7 – Cleaning Procedures – Data was received and reviewed by the project team. Witness point was not conducted. Cleaning did not have an impact on this event but was directly related to the reason for replacing the turbine and secondary chemistry performance.</li> <li>• 3.8 – Protective Coatings – Data was received and reviewed. Witness point was not conducted. Coatings did not have an impact on this event but was directly related to secondary chemistry performance.</li> <li>• 3.10 – Packing and Shipping - was observed upon blade return.</li> </ul>	<p>This was a standard grade procurement. Technical Oversight of Siemens was limited as the turbines were being manufactured. Data was reviewed for acceptability and testing was performed to validate turbine performance. Although this level of oversight is less than Quality Assurance Nuclear (QAN) procurement controls, this level of oversight is significantly more than a normal Quality Assurance Standard (QAS) grade procurement.</p> <p>Review of the data associated with these witness point by the Root Cause Team did not find any relationship to the identified root cause. Therefore, it is highly unlikely that observation of any of the allowed witness point would have prevented the event.</p>	<p>Develop a process for graded approach to quality and technical oversight based on risk and consequences.</p> <p>Consider establishing a group or third party relationship to perform vendor oversight of high risk or consequence projects.</p> <p>Consider assigning individuals specifically to oversight vendor technically to each high risk project.</p>	None  Area for Improvement

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Barrier	What is in effect?	How did barrier fail or work?	Possible Solutions	Cause Relationship
	<ul style="list-style-type: none"> <li>• 5.2 – Turbine (thermal) Performance Testing – Not Completed</li> <li>• 5.3 – Torsional Testing – Completed Documented in EMOD 40012. Acceptance criteria met.</li> <li>• BSSM testing performed based on adding tuning plates to L-0 blades. Contracted Oversight (C-11486, Section 2 Quality)</li> </ul>			
<p><b>Procedure</b> - Vendor Oversight</p> <p>Contracted Oversight (C-11486, Section 2 Quality)</p> <ul style="list-style-type: none"> <li>• 1.1 Review of QA Plan</li> <li>• 1.2 Nonconformances</li> <li>• 1.3 Owner Surveillance</li> <li>• 1.4 Witness Points</li> </ul>	<ul style="list-style-type: none"> <li>• 1.1 Review of QA Plan – Plan was reviewed in April 2006, this was too late to effect any changes that could have influenced turbine design or manufacture.</li> <li>• 1.2 Nonconformances – NCEs were not requested or reviewed for the turbine system 120hz torsional issue requiring L-0 blade modification.</li> <li>• 1.3 Owner Surveillance – There were no owner surveillance conducted.</li> <li>• 1.4 Witness Points –                         <ul style="list-style-type: none"> <li>○ May 2005, Project Manager observation</li> <li>○ April 2006, Turbine Replacement Project Engineer, Project Manager and S&amp;L Turbine Replacement Project Lead Engineer – Design Review Meeting was primary focus. Also, toured manufacturing facility. Reviewed QC documents, Reviewed info from high speed balance. Looked at setup for fitting rotor in the inner casing. Vendor QA does not perform oversight on non-QSL vendors.</li> </ul> </li> </ul>	<p>Quality oversight of Siemens was done near the end of the manufacturing process. Conducting oversight near the end of the manufacturing process decreased the probability of detecting issues and increased the likelihood that anything found would impact the project timeline or be dispositional by engineering analysis. Although this level of oversight appears weakened when compared to Quality Assurance Nuclear (QAN) procurement controls, this level of oversight is significantly more than a normal Quality Assurance Standard (QAS) grade procurement.</p> <p>The Root Cause team review of quality data did not identify any items that were related to the root cause of this event. Therefore, it is highly unlikely that observation of any of the allowed witness point would have prevented the event.</p>	<p>Develop a process for graded approach to quality and technical oversight based on risk and consequences.</p> <p>Consider establishing a group or third party relationship to perform vendor oversight of high risk or consequence projects.</p> <p>Consider assigning individuals specifically to oversight vendor technically to each high risk project.</p>	<p>None</p> <p>Area for Improvement</p>
<p><b>Procedure</b></p> <p>Corrective Action Program</p> <p>PMI-7030</p>	<ul style="list-style-type: none"> <li>• CNP CR 00802436 was written for L-0 blade balance weights.</li> </ul>	<ul style="list-style-type: none"> <li>• Vendor identified fixes and tests were implemented. Tests identified that turbine was acceptable.</li> </ul>	<p>FCN procedure was revised in 2008 to require a CR for Red or yellow coded FCN.</p>	<p>None</p>

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<b>Barrier</b>	<b>What is in effect?</b>	<b>How did barrier fail or work?</b>	<b>Possible Solutions</b>	<b>Cause Relationship</b>
<b>Procedure</b> Corrective Action Program PMI-7030 <b>Procedure</b> Operating Experience PMP-7030-OE-001	<ul style="list-style-type: none"> <li>• CNP CR 00825512 was written for a high vibration trip on February 2008.</li> </ul>	<ul style="list-style-type: none"> <li>• Equipment Apparent Cause Evaluation was completed and appropriate corrective actions were specified. Refer to the Barrier Analysis Summary below for a more detailed discussion of this event and Root Cause Team conclusions.</li> </ul>	None	None
	<ul style="list-style-type: none"> <li>• Operating experience was evaluated as part of the project and installation. Siemens had not originally recommended torsional or BSSM testing.</li> </ul>	<ul style="list-style-type: none"> <li>• OE identified an issue with torsional frequency. Use of OE ensured that the project included validation testing for torsion and BSSM.</li> </ul>	None	None
<b>Procedure</b> Human Performance PMP-4010-HUT-001	<ul style="list-style-type: none"> <li>• Risk assessment is identified above. No evidence of other Human Performance tool failures.</li> </ul>	<ul style="list-style-type: none"> <li>• Human Performance issues were not related to this event.</li> </ul>	None	None
<b>Procedure</b> Benchmarking and Self Assessment PMP-7030-SAP-001	<ul style="list-style-type: none"> <li>• A self assessment of the Project Process or the Turbine Modifications was not found.</li> </ul>	<ul style="list-style-type: none"> <li>• Two Benchmark trips were conducted that helped eliminate known project issues and specify appropriate testing to verify torsional performance.</li> </ul>	None	None
<b>Procedure</b> Conservative Decision Making	<ul style="list-style-type: none"> <li>• Decisions to make modification to the blade were questioned thoroughly and raised to the appropriate level of CNP Management.</li> </ul>	<ul style="list-style-type: none"> <li>• The appropriate questions were asked by CNP and resolved by Siemens. Refer to Barrier Analysis details for support of this conclusion.</li> </ul>	None	None
<b>Procedure</b> Inspection and Surveillance Tests	<ul style="list-style-type: none"> <li>• Torsional test was completed without strain gauges. The test was determined acceptable by Siemens. BSSM testing was not completed above 95% power. This test was also determined to be acceptable by Siemens.</li> <li>• Blade inspections conducted during the April 2008 outage were acceptable.</li> </ul>	<ul style="list-style-type: none"> <li>• The Specified and implemented inspections and tests did not detect the blade failure. The specified tests were the industry standard for new turbines.</li> </ul>	Include online blade monitoring to detect blade failures in progress.	None
<b>Procedure</b> Owner Acceptance Review 12-EHP-5043-OAR-001	<ul style="list-style-type: none"> <li>• Siemens assumed design inputs and provided design information in S32M7 / 2005 / 10523 'Analysis of Boundary Systems.' The Analysis of Boundary Systems was included in modification but was not Owner Acceptance Reviewed.</li> </ul>	<ul style="list-style-type: none"> <li>• Barrier not used and was not required.</li> </ul>	None	None
<b>Training</b>	<ul style="list-style-type: none"> <li>• CNP Turbine personnel did not have the knowledge to challenge Siemens on design and testing information.</li> </ul>	<ul style="list-style-type: none"> <li>• Utility personnel are not expected to have a comparable level of knowledge as a vendor on the vendor's design.</li> </ul>	None	None

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<b>Barrier</b>	<b>What is in effect?</b>	<b>How did barrier fail or work?</b>	<b>Possible Solutions</b>	<b>Cause Relationship</b>
<p>Barrier Analysis Summary</p> <p>The cause of the turbine blade failures was determined to be design related. CNP Oversight of the Turbine Replacement Project and actions in response to the February 2008 High Vibration trip adequately addressed the issues and did not have a relationship to the cause of this event. No CNP Organizational or Programmatic contributors were noted. An Area For improvement was noted.</p> <p>The Turbine Replacement Project implemented oversight in excess of what is normally conducted for standard grade procurements. CNP does not currently have a formal process that describes this level of performance. The Root Cause Team determined that there would be value for CNP to have a process to apply a graded approach to oversight of standard grade procurements based on risk.</p>				

Detailed Discussion

Four areas of interest were identified for detailed discussion base on the barrier analysis: Project Management from 2003 to September 2006; Installation and Testing September 2006 to November 2006; High Vibration Trip in February 2008; and U1C22 from March 25, 2008 to April 29, 2008.

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**Project Management from 2003 to September 2006**

The Root Cause Team did not identify any causal factors in the project management from 2003 to September 2006.

**Request for Proposal and Bid Evaluation**

The Request for Proposal (RFP) was based on providing bids to replace two or three rotors to eliminate a stress corrosion cracking (SCC) issue. The RFP was given to General Electric (GE), Siemens, and Alstom. Siemens and Alstom both provided bids based on a turbine replacement because these vendors would not have access to proprietary information needed to perform only a rotor replacement. The bid evaluation determined that all three bidders met the timeliness, technical and quality requirements of the proposal. In addition, all three vendors did not require torsional testing during start up. Therefore, since the technical and quality considerations of all of the evaluated options were satisfied (including the resolution of the SCC issue, the deciding factors were based on a cost benefit analysis of the proposed modifications which included the technical and quality considerations. Siemens was selected based on the overall best net present value to the Company. This value came from all of the considerations offered by the Siemens product including the increased efficiency from replacing all three LP turbines with a new 18m<sup>2</sup> L-0 free standing blade design.

Risk is a product of the likelihood of a failure (probability) and the worst case scenario (consequences) of the failure. Actions (contingencies) are specified to control risk by reducing the probability or consequences of failure.

In discussion with the Project Manager, and by review of the Feasibility Study for the Unit 1 Low Pressure Turbine Rotor Replacement (RPA 0056730), the risk evaluation for the bid proposals did not formally evaluate risks, in a quantitative sense, associated with changing the Original Equipment Manufacture (OEM), or using a first of a kind (unproven) design. The Turbine Replacement Project Management team was fully aware of the change in LP turbine rotor provider from the OEM to Siemens and the first of a kind design for the 18m<sup>2</sup> blades. Based on an evaluation of many factors including the proposals from all three vendors (including the OEM), the expertise of Siemens in the design and manufacture of turbine rotors, and a qualitative risk review of the of the change from the OEM to a new vendor and the use of 18m<sup>2</sup> L-0 blades, the decision was made to purchase and install the Siemens product. Once the contract was awarded, risk and operating experience reviews of the modification identified the need for additional verification testing to reduce the probability of failure.

The Root Cause Team concluded that although the request for proposal and bid evaluation processes could be improved by the application of risk tools focused on consequences, there was no causal relationship between these processes and this event.

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### Vendor Oversight

Contract C-11468 was a standard grade contract. The turbine 18m<sup>2</sup> L-0 free standing blade design was a first of a kind, new design, that was not extrapolated from an existing design. Contract C-11468 provided quality review and witness point as identified in the Barrier Analysis, Attachment 6.6 table. As detailed in the Barrier Analysis, Attachment 6.6 table, CNP personnel did not take advantage of all of the quality and technical oversight witness points as allowed by contract. In April 2006, the Project Engineering Manager, the Project Manager and a Sargent and Lundy Lead Engineer went to Mulheim, Germany primarily focused on the Design Review Meeting. During this trip, the manufacturing facility was toured, QC documents were reviewed, high speed balance data was reviewed, and the setup for fitting the rotor in the inner casing was observed. In addition, there was additional oversight provided in the form of meetings, teleconferences, letters, and other communications related to the design and manufacture of the rotors. The quality and technical oversight selected along with the testing specified for start up gave CNP adequate confidence in Siemens.

### CNP Design Involvement

CNP does not have turbine design expertise in-house. Therefore, the design specification and the modification package was completed by a third party design engineering consulting firm Sargent & Lundy (S&L) using CNP processes. As identified in CR 00827288, in-house design engineering involvement in the Turbine Replacement Project was minimal and did not identify weaknesses in calculations that provided input to Siemens bearing support analysis.

The Root Cause Team concluded that it is unlikely that more CNP Design Engineering involvement would have prevented this event because of the combination of factors that resulted in this turbine blade failure.

### **Installation and Testing from September 2006 to November 2006**

The major turbine equipment arrived at the plant in August, 2006, including the stationary blades, inner casings, rotors and L-0 blades. The L-0 blades were shipped separately from the rotors, due to railway clearances, and were to be installed on the rotors at the plant. Installation of the L-0 blades had begun when CNP received notice from Siemens on August 28, 2006 that there was a significant torsional issue identified with the turbine system. Siemens identified that the resonance frequency of the turbine system was too close to 120 Hz. Siemens recommend that the all the L-0 blades be returned to their Mulheim, Germany Steam Turbine Manufacturing Facility for modifications. At that time the details of the modifications had not been developed.

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Several discussions with Siemens about the impacts of this change were held between Siemens, the Turbine Replacement Project team, the AEPSC Turbine Section, and CNP Senior Management. Through Sargent & Lundy, CNP personnel also involved a former Westinghouse blade designer and a former Westinghouse torsional expert. Telephone discussions were also held with Stress Technologies, Inc about the different approaches to changing the blade frequencies.

After discussion with Siemens and other experts, on September 5, 2006, with Senior Plant Management concurrence, AEP Correspondence # 2006-984 gave Siemens permission to modify the L-0 blades with several conditions outlined in this correspondence. These conditions included process validations, engineering controls and contingency plans to ensure blades would perform satisfactorily in service.

The options for changing the blade frequency included, cutting off the blade ends to increase the frequency or adding mass to the blade tips to decrease the frequency. Since cutting off the blade ends had an impact on clearances between rotating and stationary components that would have impacted the thermal performance of the blade, the options to add mass to the blade tip were judged more desirable. A retired AEP Turbine Engineer was hired to follow the modifications being performed in Mulheim and reported to the Project Team on a daily basis.

The first attempts to add mass to the blades was performed by depositing weld material directly to the blade. Depositing weld material caused unacceptable distortion to the blade and this method was abandoned. Later attempts included welding a plate of similar material to the blade tip. The method using the plate was more successful in controlling the distortion of the blade and was the method of choice.

On September 9, 2006 Siemens made a presentation to CNP personnel on the blade modification and the impacts of the modification to the stress levels in the blade, the blade mechanics and aerodynamics, the system effects and the validation plan. This presentation was based on information that followed in S32M7 / 2005 / 10444- Rev.2, '*Torsional Studies for AEP, DC Cook Unit # 1 with 18m2 LP Rotor Retrofit*' dated 9/11/2006. Both the September 9, 2006 Siemens report and the torsional study concluded that:

- Blade stresses, aerodynamics, and the rotor system were acceptable.
- Blade frequency shift, distortion, and welding quality were acceptable.

The Turbine Replacement Project Manager identified that a risk review was not re-performed for the field change that installed the weights and the Field Change Process did not require re-performance of the risk review. Even though the process did not

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require a risk review CNP conservatively applied, many of the same considerations and contingencies that would have been identified by the risk review were addressed and approved by senior management.

The modification to all the L-0 blades was completed on September 25, 2006 and all L-0 blades were returned to the plant by September 28, 2006. The installation of the L-0 blades onto the rotors was performed such that there was no impact on the scheduled refueling outage.

The rotors were balanced with the original unmodified blades in Mulheim. Since not all the same L-0 blades were returned and the blade weights had changed after the modification; adjustments were required to be made to the blade radial locations on the rotor to accommodate the change in weights. Siemens correspondence SPG-CNP-0183 dated October 6, 2006, stated that “the impact of this change on the rotor balance was insignificant.” The L-0 blades were installed using Work Package, TG No: TG6427.00.

The original test plan for startup included torsional testing of the turbine generator, and BSSM testing on one LP rotor. An IPTE pre-job brief was performed for the BSSM testing and it was handled as a high risk evolution. A separate IPTE pre-job brief was performed for the turbine startup. Torsional testing ensures that the turbine generator train is not operating near a torsional resonance. The torsional test was performed with strain gauges on the LP C shaft and proximity probes on the turning gear. BSSM testing is a German acronym for a blade test that monitors the movements of the L-0 blade tips during operation with the use of proximity probes. BSSM testing determines the L-0 blade reaction at different loads and different condenser vacuum conditions. Following the modifications to the L-0 blades Siemens decided to perform the BSSM testing on all six rows of L-0 blades to determine if the blades responded as expected and to validate the condenser vacuum limitation curve.

As documented in the Siemens ‘*Startup and Balance After New LP Rotors*’ report, 0NGT04007646, the initial startup of the new Siemens LP turbines had to be stopped due to high vibrations. The Siemens operating vibration limit of 13.8 mils was reached at a turbine speed of 1731 rpm on the first attempt to startup. Siemens had originally balanced the turbine rotor in the bunker to less than two mils. CNP has generally operated both unit turbines below five mils. Initial startup vibrations indicated that the balance of the rotors was impacted more severely than Siemens expected and stated in SPG-CNP-0183 dated October 6, 2006, by the modifications to the blades. An acceptance criterion of less than seven mils was established by the Turbine Replacement Project Team. This is more conservative than the eight mils provided in the AEP Turbine Operating Circular Letter 4. The more conservative number was chosen because, at a nuclear unit there are fewer opportunities to make balance adjustments than with coal fired units that may be removed from service more frequently. The CNP Root Cause Team determined that these decisions were reasonable and prudent.

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During the first attempt to reach normal operating speed of 1800 rpm, the strain gauges that were on the shaft for the torsional test became non-functional. Siemens determined sufficient data was acquired to conclude the torsional test with the proximity probes at the turning gear. The Turbine Replacement Project Engineer accepted the vendor recommendation that the test could be completed with the remaining instrumentation. The CNP Root Cause Team questioned both Siemens, and MPR Associates Inc. (a third party) on this decision and it was explained that this was technically acceptable based on correlations of the strain gauge data to the proximity probe data during the initial run.

After installing two balance weights in the LP A & C rotors the vibration acceptance criteria (seven mils) was met and the startup and testing proceeded. The torsional test was completed without incident, which included manually synchronizing to the grid. The BSSM testing was also performed.

The torsional test results are included in Siemens Technical Report P11M7-06-10822, '*DC Cook Unit 1 – On-Line Torsional Response Test.*' As noted above, this test report identifies that during this test, the strain gauges fell off. Siemens determined that sufficient data had been obtained to complete the test without the strain gauges. CNP personnel supported the decisions to complete the test without the strain gauges. The CNP decision considered both the acceptability recommendations from Siemens and the outage schedule delays that that would be incurred by reattaching the strain gauges. The test concluded that "the predicted torsional frequencies have very good correlation with those measured, no torsional system frequencies were measured within the range of +/- 2 Hz of 60 Hz and or 120 Hz of the grid excitation frequencies. Therefore, there are no torsional concerns and the unit is torsionally acceptable."

The results of the BSSM testing are included in Siemens Technical Report P11M2-07-029, '*Evaluation of BSSM – Testing of 18m<sup>2</sup> last stage blade row at DC Cook #1.*' This report adjusted the Unit 1 condenser vacuum limitations to provide more operating margin. This information was used to update Tech Data Book figure TDB-1-FIG-11-19. Siemens concluded that the test was acceptable at the time. The test report does not include any information that lead the Root Cause Team to determine that test parameters were not met. The Siemens Root Cause Team identified that the BSSM testing was secured at 95% power and that testing was not completed in the conditions that Unit 1 normally operated. The Seimens Root Cause Team is further evaluating this. The Turbine Replacement Project Engineer identified that CNP Turbine Replacement Project Team was not aware of this decision.

In conclusion, CNP organization oversight of the Unit 1 Turbine Installation and Testing from September 2006 to November 2006 was intrusive, ensured risks were evaluated and decisions were made at the proper levels.

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### High Vibration Trip in February 2008

The vibrations at the number 5 & 6 bearings, which are on the LP B turbine, gradually raised from approximately eight mils to over 13 mils and the turbine was manually tripped due to high vibration. A Failure Investigation Process (FIP) team was assembled to investigate the cause of the vibration. An Equipment Apparent Cause Evaluation (EACE) was performed, which concluded that the vibration was caused by oil whip/whirl. Contributing causes were the poor lube oil temperature control, the high running vibration levels, a lightly loaded bearing, and an existing resonance near operating speed. At the time of the event the lube oil temperature recorder, 1-SG-4 and the rotor phase angle probes, were not functional. Information from these two instruments would have aided in the analysis of this event because these are two data inputs that can support oil whirl.

Since the vibration in February 2008 rose gradually over several hours as opposed to a sudden spike in vibration there was no evidence supporting a problem with the turbine blades. Therefore, the vibration event in February, 2008, was viewed as a rotor vibration/instability issue and not a problem with the L-0 blades. The following actions were taken between February 2<sup>nd</sup> and February 5<sup>th</sup>, prior to the return of the unit to service.

1. Two balance weights were installed in the LP B turbine to reduce the vibration to less than 4.5 mils, down from eight mils prior to the event. This balancing established a more stable turbine rotor that was less susceptible to operational variations. Balancing was completed under WOT 55313226-06.
2. Visual inspections of the L-0 blades and balance weights were made through the exhaust hood manways. No physical damage was identified. The inspections were completed under WOT 55313226-03.
3. A higher operating temperature range for the lube oil was specified to provide more margin before CNP would get conditions that would contribute to oil instabilities. This lube oil temperature range change was accomplished with input from Siemens and is documented in AR 00825512.
4. To improve CNP diagnostic ability and to support the balancing of the turbine, the rotor phase angle probes were repaired. These probes were not functional prior to this event in February.
5. The lube oil temperature recorder, 1-SG-4 was repaired under WO 55311223.
6. The lightly loaded bearing issue was not addressed in February 2008 because this was not the most likely cause. Plans were made to check the coupling alignment that would contribute to the lightly loaded bearing #5. In February 2008, alignment was believed to be the most likely cause of the lightly loaded bearings.

As a result of the vibration incident in February, CNP and Siemens personnel planned additional inspections prior to and during U1C22. This plan included expanding the 100% visual inspection of the L-0 Blades planned for U1C22 to include a Dye Penetrant (PT) of the 100 LP B L-0 blade tips.

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CNP Personnel also requested a third party, Engineering Dynamics, Incorporated (EDI), to help assist in determining the cause of the excessive vibrations observed in February 2008 by conducting on-site vibration testing. This testing was conducted between 3/17/08 and 3/20/08 and is documented in EDI Technical Report 93370-01, 'Operating Deflection Shape and Shutdown Testing LP Turbine A, B, and C.' EDI Technical Report 93370-01 report concluded: "The results of these tests indicate that the unit is operating near a critical speed. This makes the vibration levels very sensitive to unbalance and misalignment. This critical speed is influenced by the effective structural stiffness of the bearing housing supports."

The Equipment Apparent Cause team concluded that the above actions addressed the high vibration which contributed to the Unit 1 turbine initial instability, the oil temperature variability, and provided reasonable assurance that there was no physical damage to the L-0 blades. The L-0 blades are typically the highest stressed blades because the blades are the largest. By inspecting the L-0 blades CNP personnel had reasonable assurance that there was no damage to the blades. If there was damage, or missing blades on other stages inside the turbine, it was likely that any liberated blades would have gone through and damaged the L-0 blades. CNP inspected the L-0 blades including the tip area and since CNP personnel saw no damage to the L-0 blades, CNP personnel concluded that there was no blade damage in the LP turbines.

The Root Cause Team determined that the evaluations, testing and actions taken for the February 2008, high vibration trip were reasonable and prudent.

**During U1C22 - March 25, 2008 to April 29, 2008:**

On March 25, 2008, while removing the unit from service for U1C22 and with special procedure 1-SP-286, the turbine speed was raised to 1900 rpm to determine if the critical speed was near 1800 rpm. This test validated that there is an operating resonance just above 1800 rpm (1800 to 1842 RPM) that has an impact on the vibration at 1800 rpm. The turbine was balanced to less than 4.5 mils prior to return to service. Action 13 of the EACE 00825512 and Work Order (WO) 55323969-01 are tracking the change to stiffen bearing supports to resolve this issue. Bearing Stiffening was scheduled for U1C23 and will now be completed prior to return to service from this forced outage via WO 55323969.

WRV-970 – 'NESW To Main Turbine Lube Oil Tank Coolers Control Valve' was replaced with a ball valve that is less susceptible to sticking due to silt and sand. Replacing the control valve is the permanent fix to the lube oil temperature control problem. Replacing the control valve was performed under WO 55311015.

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The alignment between LP A and LP B was checked looking for lightly loaded bearings. The alignment at this time was considered good. Siemens also performed harmonic tests for resonance at the LP bearings that confirmed that none of the bearing supports were as stiff as Siemens had expected. In particular, the #5 bearing supports indicated less stiffness than the other bearings. The coupling alignment was performed under WR 06360662 and the Siemens test is documented in Siemens report 1NGT08011701 '*LP Pedestal Fast Fourier Analysis Testing.*'

All 300 L-0 blades on the turbine were visually inspected by Siemens personnel as originally scheduled. This inspection is documented in Siemens report 0NGT08011701 '*L-0 Blades NDE.*' The results were acceptable.

The LP B L-0 blades were Dye Penetrant (PT) tested in the area of the welded on weights. This activity was added to the outage scope after the February event as an additional inspection on LP B since the vibration in February was focused on that rotor. This inspection is documented in Siemens report 0NGT08011701 '*L-0 Blades NDE.*' One indication was found on one blade (#76 on LP-B) which was accepted.

The bearing supports in the exhaust hood were inspected with no anomalies identified. This inspection was documented in WOT 55315028 -04.

U1C22 Post-Outage Data Review:

The blade inspections were acceptable, thus CNP personnel were given no reason to be concerned about the integrity of the L-0 blades. The new lube oil control valve, 1-WRV-970 was performing well, but the true test would be in the colder winter months.

Based on the resonance near the operating speed identified by the EDI report and by Siemens' Fast Fourier Analysis testing and the fact that the coupling alignment was good, the focus turned to the stiffness of the #5 bearing. CNP System Engineering was working with Siemens to provide a modification that would stiffen the supports for all the LP bearings. The drawings for this modification were under development in September and the work was scoped into the U1C23 outage.

The Root Cause Team determined that the evaluations, testing and actions taken during the 2008 refueling outage were reasonable and prudent.

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**Root Cause Team Review of CNP Organization Decisions Made Regarding the Turbine and L-0 Blades:**

CNP appropriately provided the turbine upgrade request for proposal to three world class vendors with the necessary technical expertise and experience. CNP also appropriately selected the replacement turbine based on meeting all the request for proposal requirements and providing the best net present value. This value came from all of the considerations offered by the Siemens product including the increased efficiency from replacing all three LP turbines with a new 18m<sup>2</sup> L-0 free standing blade design. The turbine 18m<sup>2</sup> L-0 blade design was a first of a kind, new design, that was not extrapolated from an existing design.

Once the turbine replacement design was selected CNP conducted appropriate risk reviews, operating experience reviews and benchmarking. These reviews and benchmarking resulted in applying additional controls and testing to ensure that industry events did not repeat at CNP. Based on the identified risks, CNP also chose to apply quality and technical oversight to the vendor in excess of what was required by the process.

When the torsional issue was identified by Siemens just prior to the turbine replacement installations, the appropriate questions were asked by CNP and resolved by Siemens. CNP engaged third party reviews and assigned a turbine engineer to follow the modification in Germany. The issues, risks, proposed solutions and contingency actions were appropriately elevated to CNP Senior Management.

CNP Personnel believed that the turbine, including L-0 blades, was thoroughly tested after initial installation, during the startup from the U1C21 refueling outage. These tests included the BSSM testing of the L-0 blades, and torsional testing of the shaft line. The BSSM testing monitored the blade tip movement during all phases of startup including variations of condenser vacuum. Note that the Siemens Root Cause Team identified that BSSM testing was secured, at 95% power, and did not cover all of the conditions at which Unit 1 normally operated. Siemens identified in their January 2009, presentation on the DC Cook #1 Siemens Root Cause Analysis that “Unit 1 operation was generally above the maximum MWth reached during the 2006 BSSM test.” CNP Turbine Replacement Project personnel were unaware that BSSM testing data was not collected above 95% power. CNP Turbine Replacement Project personnel were aware of the decision to complete the torsional tests without the strain gauges. CNP personnel approved the decision to startup with less than or equal to seven mils vibration. These testing results, as provided by Siemens in 2006, indicated that the turbine performed well. Siemens recommendation for these blades was to perform a visual inspection during each refueling outage and to inspect the LP rotors on a 10 year inspection interval.

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Following the vibration incident in February 2008, Siemens also agreed to perform NDE of the LP B blade tips where the plates were welded on to adjust the blade frequencies prior to installation of the LP rotors. There was an indication in one of the blade tips that was dispositioned as satisfactory. Siemens also performed a visual inspection of all the L-0 blades on all three rotors. These inspections were satisfactory.

The inspections and testing performed were consistent with the manufacturer's recommendations and there was no industry OE that suggested an enhanced inspection program was needed. In fact, Siemens' OE with replacement of GE nuclear turbines in Limerick and Susquehanna revealed no problems with cracking of 13.9m<sup>2</sup> L-0 blades.

CNP personnel also believed that the inspections and tests specified by Siemens were appropriate based on CNP experience with Unit 2. CNP Operating Experience with free standing L-0 blades on Unit 2, which are a similar design by a different manufacture, has been very good. Visual inspections of the Unit 2 L-0 blades are performed during each refueling outage. A more thorough NDE inspection is performed during each Unit 2 LP rotor inspection on a Four Refueling Cycle (4R) frequency.

The February 2008 vibration trip was considered a rotor vibration or stability issue and there was no evidence that the issue had any causal relationship with the L-0 blade failure. The information about the bearing support stiffness was not fully apparent until after the spring 2008 refueling outage was over. Since the spring 2008 refueling outage completion, CNP personnel were working with Siemens to provide drawings to add stiffening at the bearing supports. This work has been included in the U1C23 outage scope. There was no evidence that the bearing support issue had any relationship to the L-0 blade failures.

Overall, the Root Cause Evaluation team concludes that CNP organization decisions made in the initial installation and testing of the turbine showed a reliance on the vendor, which was supported by the vendors industry standing and CNP oversight of the vendor. These decisions were reasonable and prudent, based on the information available to CNP personnel prior to September 20, 2008.

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## **6.7 PII FAILURE DIAGNOSTIC CONCLUSIONS**

The Executive Summary of the PII Failure Diagnostics is attached below. The complete report will be attached to CR 00838732, Assignment 12.

### **1. EXECUTIVE SUMMARY**

On September 20, 2008 D. C. Cook Unit 1 suffered significant damage to its main turbine as the result of multiple blade failures which caused a severe imbalance in the turbine. This, in turn, damaged the rotor and bearings as well as associated support systems. Three L-0 blades were found to have suffered high cycle fatigue from the beginning of their operation. Blade #40, located on low pressure turbine B (LP B), is believed to have ruptured due to high cycle fatigue. This precipitated the failures of blades #56 on LP B and blade #189 on LP C which had suffered high cycle fatigue as well. The failures of blades #40 and #56 caused the overload failure of two additional blades on LP B. All four failed blades on LP B and the failed blade on LP C were on the same side of the rotor which caused severe rotor imbalance.

Extensive resonance testing on an actual L-0 blade and computer modeling identified reasonable operating stresses in the typical L-0 blade. The computer model further identified that the peak stress seen at the weakest point (at the root of the blade) would be increased if the blade dimensions were such that the three attachment pairs were not evenly sharing their loads. The critical dimension appears to be the radial distance between the upper attachment and the middle and lower attachments on a given blade and the corresponding disk grooves into which they fit. Post event measurements showed dimensional differences between cracked blades and uncracked blades but the as-manufactured dimensions show no obvious differences. Additional inspections are being conducted.

This analysis concludes that the root cause of the D.C. Cook Unit 1 turbine failure was a blade-rotor system design which failed to provide adequate stress margin in at least three L-0 blades. This caused those three blades to occasionally exceed their stress threshold at the highest stress location thereby suffering high cycle fatigue cracking. Variations in the attachment engagement of individual blades may have been the reason why only three blades displayed the cracking. The normal blade design was modified by adding a welded tuning weight to the tip which could lead to additional variation in each blade. Normal minor electrical grid variations correlate well to the distinctive beach marks observed. Bearing #5 demonstrated a lack of rotor support and was found to have backed out bolts and a cracked ring. The stiffness of the pedestals was lower than assumed in the design and lower than seen in similar turbines. There are indications of coupled system stiffness changes during normal operation.

In addition, the blade design, at Cook, with tuning weight addition modifications resulted in a local reduction of fatigue strength which allowed high cycle fatigue cracking in the tip area of some blades. Had this secondary failure mechanism not been identified it could have led to loss of a blade tip and a turbine outage.

Extensive corrective actions are recommended to ensure the repaired and replacement turbine system does not have similar or new weaknesses. These actions address: Prevention, Detection,

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and Correction of issues in the areas of blade design, torsional vibrations, and turbine generator support system. Given the turbine problems at Cook Unit 1 since 2006, it is essential to go well beyond standard industry practice in these areas.

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**6.8 OPERATING EXPERIENCE / BENCHMARKING**

Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
<b>OE FROM THE MODIFICATION PACKAGE</b>				
External	SER 5-02  CR 02273023	Lessons Learned from Power Upgrades	<p><b>Lesson:</b> Lessons included setting up dedicated Project Managers and team members with no additional duties. Team members included a full time Senior Reactor Operator (SRO) from the beginning of the project and involvement of the Training Department. Successful team schedules included sufficient lead time to allow for data analysis.</p> <p><b>Actions Taken:</b> The project for the CNP Unit 1 LP turbine replacements had a dedicated Project Manager but no other dedicated team members until February, and March 2006 when one team member was added each month. The turbine replacement was not considered the same complexity as a power uprate and didn't require a full time SRO. The Project Manager identified that the timeline was aggressive, but necessary to resolve a stress corrosion cracking issue that would require increased inspections on the GE turbine being replaced. The Project Manager identified that support was obtained from AEPSC Turbine Section and Sargent &amp; Lundy.</p> <p>Project team support was increased as the project neared the implementation phase.</p>	Lessons Applied
External	OE10158	Secondary Chemistry Exceeds PBNP Action Level 3 Due to New Turbine-Condenser Part Contamination	<p><b>Lesson:</b> Startup with new turbine components resulted in exceeding sulfates and organic corrected conductivity levels. Contributors to the chemistry problems were the preservatives and solvents used during manufacturing and shipping as well as the handling of the equipment.</p> <p><b>Actions Taken:</b> Chemistry cleanliness was monitored very closely</p>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			during the installation of the LP turbines. Chemistry personnel inspected and swiped each component for contaminants. Every component was cleaned with alcohol and distilled water prior to installation. The result was that the secondary steam chemistry during startup was very good. No stress corrosion cracking evidence.	
External	OE18793	GE Monoblock LP rotor replacement results in Challenges to EPRI feedwater oxygen levels during startup.	<p><b>Lesson:</b> Startup requirements for GE monoblock rotors require more stringent warm-up requirements which takes more time at low loads and this led to oxygen level issues.</p> <p><b>Action taken:</b> None, CNP did not install GE monoblocks so this was not applicable.</p>	N/A
External	SER 1-05 CR 05066025	Steam Pipe Break from Extended Operation with Valve Failed Open	<p><b>Lesson:</b> This SER discusses problems associated with feedwater level control valves and the potential for FAC and pipe vibration that can impact operation of the secondary equipment.</p> <p><b>Action Taken:</b> None</p>	N/A
External	OE18924	Project Management Style Changes for the 2004 LP Turbine Replacement Program	<p><b>Lesson:</b> Many of the lessons in the OE are covered in the SER 5-02. Additional OE included managing crane maintenance with full time crane support, use of Challenge Boards and dry runs of critical path tag-out boundary walk downs.</p> <p><b>Action Taken:</b> Pre-Outage Challenge boards and review boards were conducted, including the Design Review Board and the Testing Review Board. Crane support was addressed. The Siemens site team was actively involved in the Pre-Outage planning</p>	Lessons Applied
External	EPIX Failure # 310	Vibration due to rubs at oil seals March, 2003	<p><b>Lesson:</b> Previous Siemens installations into GE turbines at Limerick Unit 2 had experienced rubs on oil seals during low vacuum conditions. These rubs resulted in high turbine vibration and a</p>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			turbine trip.  <b>Action Taken:</b> Discussed this with Siemens and Limerick. As a result, changes were made to the oil seal clearances on the lower half. Therefore CNP did not experience this problem.	
External	OE17436	Plant Startup Delays Due to Vibration Problems With New Mono Block Low Pressure Turbine Rotors	<b>Lesson:</b> Delays were due to the specific design of the GE Monoblock rotors and operational issues with that design. This OE also discussed adjusting clearances to avoid rubs which is discussed in EPIX Failure #310  <b>Action Taken:</b> No additional action beyond what is discussed in the EPIX # 310	N/A
<b>BENCHMARKING FROM THE MODIFICATION</b>				
Internal	CR 04020033	January 22, 2004 Trip to AEP Headquarters to meet with Turbine Engineering Section	<b>Lesson:</b> Technical evaluation matrix was refined based on input from the AEP Turbine Section. Benchmark data was incorporated into the matrix. AEP recommended paying careful attention to the torsional analysis commitments in the proposal.  <b>Action Taken:</b> The technical evaluation was updated and the information on the torsional analysis was included in the proposal.	Lessons Applied
Internal	CR 04342149	Trip to Calvert Cliffs on June 7 & 8, 2005 to gain insights on LP Turbine replacement	<b>Lesson:</b> Project management processes and procedures were reviewed as well as impact on steam chemistry during initial startup. Calvert Cliffs did not use a design change document because Calvert Cliffs considered the replacement to be a like-for-like replacement. Therefore, Calvert Cliffs did not perform a design impact study.	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			<b>Action Taken:</b> Lessons from the trip were incorporated into the project management, including the cleanliness for steam chemistry, crane maintenance, and managing installation activities.	
<b>SEE-IN DOCUMENTS REVIEWED</b>				
External	SER 4-05 AR 05280020	Errors in the Preparation and Implementation of Modifications	<p><b>Lessons:</b> Errors associated with Modifications had the following common causes:</p> <ul style="list-style-type: none"> <li>• Insufficient knowledge and skills with new technology</li> <li>• Inadequate failure modes and effects analyses (FMEA)                             <ul style="list-style-type: none"> <li>○ Some modification weaknesses were not identified because a FMEA was not conducted.</li> </ul> </li> <li>• Inadequate scope of post modification testing</li> <li>• Over reliance on the expertise of supplemental personnel                             <ul style="list-style-type: none"> <li>○ In some events, monitoring of modification activities was insufficient because the plant staff placed too much trust and confidence in the vendor’s capabilities or assurances, especially for new technologies</li> </ul> </li> </ul> <p><b>Relevance:</b>                      This SER was still being evaluated by CNP Design Engineering during the preparation of this modification but was available. Although the SER was not formally addressed in the project OE review, the concepts were implemented.</p> <ul style="list-style-type: none"> <li>• The project engaged the AEPSC Turbine Section.</li> <li>• An adequate FMEA was performed.</li> <li>• The industry standard for post modification testing was applied and included, dynamic, torsional and BSSM testing.</li> <li>• Siemens had performed retrofits on several other GE turbines by replacing the rotors and steam paths and had good performance. The project considered overall vendor</li> </ul>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			<p>performance and technical issues from this retrofits. This combined with the quality oversight conducted and testing specified gave CNP confidence with the vendor.</p>	
External	SER 18-90	Problems Experienced During a Special Test of the Main Turbine.	<p><b>Lesson:</b> A special test, that had the potential to damage the main turbine, was continued even though unexpected plant and equipment responses were received. A manual trip was ultimately required in order to rapidly slow the main turbine when high vibration resulted.</p> <p>This event is significant because the test was inadequately controlled. A similar lack of control of testing, under slightly different conditions, could result in a challenge to reactor safety.</p> <p><b>Relevance:</b> Project Manager was aware of this SER and questioned the vendor recommendation for off-line testing of the Turbine Generator. Vendor changed the test plan so that offline testing was not performed and data was collected with safer online turbine test.</p>	Lessons Applied
External	SOER 91-1	Conduct of Infrequently Performed Tests and Evolutions	<p><b>Lesson:</b> This SOER is incorporated into PMI-4090, 'Criteria for Conducting Infrequently Performed Tests or Evolutions' at CNP.'</p> <p><b>Relevance:</b> There were IPTE briefs for the startup which included the torsional test of the GE rotor and the startup testing in November 2006.</p>	Lessons Applied
External	SER 5-87	Low Pressure Turbine Blading Failures	<p><b>Lesson:</b> This OE discusses a blade failure from operation at low-load and high condenser backpressure conditions.</p> <p><b>Relevance:</b> During the Cook event the Siemens turbine was operated within the backpressure limits. This failure mechanism was refuted as a cause for the Cook event.</p>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
External	SER 26-93	Main Turbine Damage Induced by Torsional Vibration	<p><b>Lesson:</b> Cyclic fatigue, induced by resonant torsional vibration of the Susquehanna Unit 1 turbine-generator rotor system, resulted in failure of several low-pressure stage blades. Two rotating turbine blades broke off the turbine rotor and contacted low pressure turbine airfoils and diaphragms. As a result, several hundred metal fragments passed through the last stage of the turbine into the condenser, causing extensive damage. The loss of the blades unbalanced the turbine rotor, causing sufficiently high vibrations to generate a high-vibration turbine trip and subsequent reactor trip.</p> <p>This event is significant because extensive plant equipment damage was caused by a mechanism induced by transmission grid imbalances that were within normal operating parameters. In addition, consequential damage to the condenser produced a high conductivity excursion in reactor chemistry from the presence of raw circulating water in the reactor coolant.</p> <p>The following are lessons learned from reviewing this event:</p> <ol style="list-style-type: none"> <li>1. Turbine failures caused by torsional vibration can occur in stable transmission systems within less than one operating cycle.</li> <li>2. Turbine torsional testing can determine the location of torsional vibration harmonics more accurately than existing analytical techniques.</li> <li>3. Torsional vibration, which can lead to fatigue failures if unmitigated, exists in all turbine-generator systems.</li> </ol>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			<p>4. Turbine torsional testing to accurately determine the frequencies of torsional vibration harmonics has been accomplished without performing out-of-phase synchronization of the generator.</p> <p>Torsional vibrations testing was conducted as part of the startup testing and found to be acceptable.</p> <p><b>Relevance:</b> Even though startup vibrations, torsional and BSSM testing performed on the Siemens generator were acceptable, Cook also exhibited HCF failures that were attributed to grid variations within normal operating parameters. This OE was used by the Root Cause Team to evaluate negative sequencing.</p>	
External	SEN 107,	SEN 107, including Supplement 1 and 2, Main Turbine, Generator, and Exciter Damage	<p><b>Lesson:</b> This SEN discussed turbine damage and a hydrogen fire at Fermi 2.</p> <p><b>Relevance:</b> The Event description is similar to the Cook event. The summary contained limited lessons learned that could be applied to either the project or this Root Cause Evaluation.</p>	None
External	SEN 262,	SEN 262, Main Turbine Damage Because of a Low-Pressure Turbine Blade Failure	<p><b>Lesson:</b> Metallurgical examination determined that the blade failed because of high-cycle fatigue, which analysis indicates was the result of vibrations from operation near the approved condenser backpressure limits.</p> <p><b>Relevance:</b> The failure mechanism was attributed to Stall-Flutter and long term actions were associated with performing dynamic analysis and installing long term blade analysis capabilities. BSSM testing performed at Cook by Siemens as part of the 2006 startup confirmed that there was not a Stall-Flutter condition on the L-0 blades. The adequacy of this testing was questioned in the Siemens Root Cause Evaluation because the testing was secured at 95% power and did not envelop the conditions in which Cook</p>	None

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			<p>normally operates.</p> <p>Long Term Blade monitoring should be considered for the new blades.</p>	
<b>EXTERNAL OE SEARCHES OF CNPOE TURBINE VIBRATION AND TURBINE TRIP (5 HITS)</b>				
External	OE23117	<p>Watts Bar - (Follow Up to OE22846)                      Manual Reactor/Turbine Trip Due To High Turbine Vibrations</p> <p>Posted: 8/16/2006 4:36 PM</p>	<p><b>Background:</b> Watts Barr Unit 1 tripped from 100% power due to high vibration when one L-0 blade was liberated from the rotor. Watts Barr is a Westinghouse Design turbine with 44" L-0 blades that are tied together in groups of four with lashing lugs. Failure of the L-0 blade was attributed to Stall-Flutter condition which is created when the operating backpressure limits for the turbine are not adhered to. Watts Barr operated outside their approved limits for a short period of time which led to the failure.</p> <p><b>Relevance:</b> Watts Barr was operating outside the OEM recommended backpressure limits. CNP Unit 1 has operated within the OEM backpressure limits since the installation of the Siemens Turbines with the exception of initial testing which was closely monitored by Siemens.</p>	N/A
External	MER ATL 08-226 OE26787	<p>Manual Turbine Trip Due to a Rise in Main Turbine Vibrations (Pilgrim, 5 April 2008).                      Posted: 6/2/2008 1:05:37 PM</p>	<p><b>Background:</b> Pilgrim is a GE turbine with Monoblock rotors. During power descent for a planned outage to repair a leaking safety relief valve, the Main Turbine developed an increasing trend in vibration after reactor power had been lowered to approximately 10 percent (43 MWe). The increasing trend resulted in operator action to trip the main turbine earlier than scheduled.</p> <p><b>Relevance:</b> Vibration due to rubs with Monoblock rotors at low loads is not uncommon in the industry. GE reviewed the operating data and confirmed that the unit was operated within the</p>	N/A

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			recommended parameters. CNP Unit 1 does not have Monoblock rotors so this is not applicable to CNP.	
External	OE15882	Manual Turbine Trip and Automatic SCRAM Due To High Turbine Vibration March 3, 2003	<p><b>Background:</b> Limerick Unit 2 experienced a Manual Turbine Trip and Automatic SCRAM Due To High Turbine Vibration. The vibration was caused by a rub at an oil seal</p> <p><b>Relevance:</b> This is the OE that is related to the EPIX Failure # 310 included in the MOD package.</p>	Lessons Applied
<b>EXTERNAL OE SEARCHES OF CNPOE TURBINE TRIP (256 HITS)</b>				
External	OE11439	High Vibration on #8 Bearing Caused a Turbine Trip and Subsequent Reactor SCRAM September 17, 2000	<p><b>Background:</b> On September 17, 2000, at 1520, NMP2 experienced a turbine trip and subsequent reactor SCRAM from approximately 70% power as a result of high vibration sensed on turbine bearing number eight.</p> <p>The root cause of the event has been determined to be the result of maintaining lube oil temperatures low in the normal operating band (110-120 degrees F). The corrective action was the normal turbine lube oil temperature operating range was changed to 117 to 120 degrees F.</p> <p><b>Relevance:</b> Some Turbine rotors are sensitive to low lube oil temperatures. The February, 2008 high vibration trip on Unit 1 was similar to this OE. This OE may have been used to prevent the February, 2008 trip, but was not relevant to this Root Cause.</p>	None
External	OE7302	Nine Mile Point Unit 2 Manual Reactor Scram and	<p><b>Background:</b> All three low pressure turbine rotors were replaced with General Electric monoblock rotors during the plant's fourth refueling outage. During the first rollup, the turbine was tripped</p>	Lessons Applied

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Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
		Turbine Trip Initiated Because of Turbine High Vibration Posted 03 Jun 1995	<p>after ten minutes because of high vibration (14.5 mils) on the number three bearing. The turbine was warmed an additional four hours before a second roll was attempted. When the second roll was attempted, high vibration (&gt;14 mils) on the number six bearing was observed and the turbine was tripped from 1430 RPM. During the coastdown, vibration increased to an indicated value of between 30 and 54 mils as the turbine coasted through its critical speed.</p> <p><b>Relevance:</b> This OE is another example of vibration during startup caused by rubs with a monoblock rotor. CNP do not have monoblock rotors but the startup procedure was changed to enable adjustments to speed and load to manage vibration caused by rubs.</p>	
External	STP CR 02-10972-7 OE15951 CNPOE 03-000915	South Texas Project – Root cause on failed L-0 blade December 15, 2002	<p><b>Background:</b> STP experienced a failed L-0 blade during operation of Unit 2 in December, 2002. The blades failed due to high cycle fatigue induced by torsional vibration. The entire rotor train has several vibration modes that reside near 120 Hz (modes 19-24). The vendor, Siemens-Westinghouse, using their torsional analysis model input a 5% negative sequence at each of the vibration modes near 120 Hz. The analysis model determined that each of the modes near 120 Hz were non-excitable modes. The vendor’s design criteria are to maintain any torsional frequencies near 120 Hz a minimum of 3 Hz away from 120 Hz. In this case, due to the modes being analyzed as non-excitable, the design was deemed acceptable and the vendor took no further actions. During normal Turbine-Generator operation there are steady state excitation forces that occur at twice the electrical frequency (120 Hz). These forces, known as negative phase sequence currents, result from unbalanced transmission system voltages and act upon the generator rotor via the generator stator through the air gap. The forces create torque in the opposite direction of normal generator rotation. Discussions</p>	Lessons Applied

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.8**

Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
			<p>with the vendor show that a site specific torsional vibration analysis was not performed for the South Texas Project until 1997 and prior to 1997, the vendor relied on comparisons with a different plant of similar, but not the same design.</p> <p><b>Relevance:</b> The torsional vibration calculations that Siemens provided STP used some assumption for the generator. The torsional analysis that Siemens performed for CNP was based on generator information from other GE units where Siemens had replaced the LP turbines and was validated through testing.</p> <p>The initial torsional study based on a LP rotor that Siemens performed showed that the Unit 1 turbine rotor results were favorable. A revised study, based on the whole train, performed in the Summer 2006 showed that torsional vibration was an issue and that the Unit 1 turbine system needed to be modified to change the frequency of the turbine system. This was accomplished by adding weights to the L-0 blades prior to installation. Two actions were specified. 1) Modify Turbine Generator rotor to move the rotor frequency away from 120hz. 2) <u>Off-line</u> torsional tests were performed to verify natural frequency away from 120hz.</p> <p>This OE was sent for information to the CNP Turbine Engineer. The AEPSC Turbine Section was also aware of this OE and specified <u>online</u> torsional test to be performed on the new turbine.</p>	
<p><b>INTERNAL OE SEARCHES OF VENTYX FOR ITEMS ASSOCIATED WITH CAUSES (84 HITS)</b></p>				
<p>The Root Cause was design related. Therefore, A Business Objects search of Action Tracking data, 1/1/2006 to 12/19/08 was conducted on cause codes for ‘Design Configuration and Analysis, Inappropriate Manufacturing Standards Applied, Interface Design, and Configuration/Design Change.’ to look for root causes and actions that may be related to either the cause or lessons learned found in this Root Cause Evaluation. No condition reports were found associated to the turbine design root cause.</p>				

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.8**

Type	Doc. #	Title/Description	Review Comments	Significance (Impact on this Event)
Internal	CR 00829848	Support 1-2-GRH-R508 Removal & Waterway Interference  January to April 2008	<p>The root cause for removing the seismic restraint and failure to maintain clearances was found to be the inadequate coordination and identification of responsibilities concerning development, verification, and installation of large complex modifications</p> <p>CATPR – Revise PMP-5040-MOD-007 and PMP-5040-ECC-001 to improve the coordination and identification of responsibilities for these activities based on scope or discipline breakdown, establish a qualification requirement for design verification, and CNP discipline design supervisor review of modifications prepared by consultants.</p> <p>CATPR – Revise PMP-5040-DRB-001 and/or develop new procedure to strengthen station ownership of modifications by integrating the Design Review Board and modification impact meetings.</p> <p>CA - Develop and implement a “perform design verification” qualification with initial and continuing training required to reinforce expectations on conduct of verification.</p> <p><u>Contributing Cause and Corrective Actions</u></p> <p>In addition to the primary responsibilities associated with modification development, multiple quality barriers (design review board; engineering risk analysis; modification impact meetings) failed to identify and prevent the issues.</p> <p>CA –12-EHP-5040-RIS-001 revision 3 was effective 5/15/08 to include evaluation of installation risks and challenges (on design as well as on schedule) associated with large modifications</p>	None - Actions were taken for this Root Cause after the Turbine Replacement Project was implemented.

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.8**

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**Summary:**

The OE in the MOD package focused on industry experience with turbine upgrades and to a lesser extent major modifications to the plant. The OE that was included in the package addressed specific technical issues. This information was incorporated as appropriate. Some of these technical items were the OE about the oil seal rubs, EPIX Failure # 310, on the start-up chemistry control, OE10158; and the STP torsional issues from the benchmarking trip to AEP Turbine Section, CR 04020033.

Benchmarking was conducted by a visit to the AEPSC Turbine Section, and a trip to the Calvert Cliffs Station. These trips resulted in some useful input but again were narrowly focused on replacing the main turbine.

Overall, OE was used throughout th project to prevent events and no OE was found that could have been used to prevent this event.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.9**

**6.9 WHY STAIRCASE**

**Equipment Why Staircase**

Unit 1 reactor manually tripped on  
September 20, 2008 @ 20:05

Why

Main Turbine Elevated Vibrations and a hydrogen fire

Why

Loss of 4 LP B L-0 blades and 1 LP C  
L-0 blade

Why

2 LP B blades failed due to high cycle fatigue causing 2 more blades  
to fail in overload. 1 LP C blade failed on high cycle fatigue.

Why

The L-0 turbine design involved a stress in the L-0 blade root location that would be susceptible  
to fatigue cracking if an initiator was present.

Why

Design margins did not adequately address normal operating conditions and manufacturing  
methods. **Root Cause – CATPR needs to address additional design or special process**

Why

Siemens designed a new LP turbine retrofit with their latest technology which did not  
specify design, manufacturing, special process controls or testing sufficient to detect  
and correct the design flaw.

Why

Siemens didn't realize there were other factors not verified by the specified  
testing. As a result additional design or special process controls are needed.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.9**

**CNP Organizational and Programmatic Why Stair Case**

CNP selected the 18m<sup>2</sup> Blades Design

Why

The Turbine Projects considered the consequences of a turbine failure to be unacceptable and chose to reduce the risk by decreasing the probability of a turbine failure. The controls were to: 1) offer the bid to world class vendors with significant experience in turbine design and manufacturing (GE, Siemens and Alstom) – AND - 2) Based on industry OE, prescribe torsional and BSSM testing in additions to normal manufacturing and startup vibration testing.

Why

Siemens was world class vendor with experience in turbine retrofits.

And

The Siemens representation of the LP turbine retrofit with 18m<sup>2</sup> L-0 free standing blade design was the most efficient design and best net present value that eliminated the stress corrosions cracking issues and provided decreased inspection frequency.

And

Siemens, AEPSC Turbine Sections and CNP believed that bunker testing, dynamic, torsional and BSSM testing would be sufficient to detect and correct any issues.

Why

The testing selected was the industry standard for detecting turbine issues.

And

Siemens, AEPSC Turbine Sections, and CNP didn't realize there were other factors not verified by the specified testing. As a result additional design or special process controls are needed.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.10**

**6.10 DOCUMENTS REVIEWED**

DOCUMENTS REVIEWED			
TYPE	DOC. #	DATE OR REV.	TITLE/DESCRIPTION
Agenda Results			Agenda Items Covered in Melham in April 2006
Calculation	SD-060310-002	0	Vibration Analysis of the Unit 1 Steam Turbine Generator Pedestal Structure
Calculation	DC-D-3900A2-SC	0	Turbine Foundation
Challenge Board Summary Report		05/19/2006	LP Turbine Rotor Project Summary Report
Contract	C-11486		LP-Turbine upgrade between Siemens and AEP
CR	00802436		New LP Turbines have torsional vibration concerns
CR	00811793		Track the L-0 Blade inspection recommendations
CR	00827288		Lack of Ownership in Re-design of U1 Low Pressure Turbines
CR	00839054		Unit 1 Main Turbine Lube Oil Spill & Clean-up
CR	00825512		Elevated vibrations on Main Turbine bearings 5Y & 6Y
DTG	BP-0006	6/1/05 Rev. 1	AEP Capital Improvement Requisition and Approval
DTG	DTG-MOD-002	5	Desktop Guide for the Installations of Design Change Modifications at the Cook Nuclear Plant
EDI Technical Report	93370 – 1	4/9/08	Operating Deflection Shape and Shutdown Testing LP Turbines A, B, and C Cook Nuclear Power Plant – Unit #1 ( <i>Engineering Dynamics, Incorporated (EDI) was a third party review contracted to assist in determining the cause of the February 2008 high vibrations</i> )
EPRI	1004963	December 2004	Turbine Condition Assessment and Monitoring Methodology
EPRI	1011679	November 2005	Steam Turbine-Generator Vibration Interaction with Electrical Network
EPRI	1004559	December 2002	Noncontacting Detection of Turbine Blade Vibration
EPRI	1014137	March 2008	Steam Turbine Blade Failure Root Cause Analysis Guide
EPRI	1013460	November 2006	Torsional Interaction Between Electrical network Phenomena and Turbine-Generator Shafts
FCN	FCN-46925-004		Add mass to L-0 Blades to separate rotor train frequency from the critical range.
Feasibility Study	RPA005673	4/30/04	Report of Feasibility Study, Unit 1 Low Pressure Turbine Rotor Replacement.
Modification	1-MOD-40012 EC-MOD-EMOD-0000046925	0	Unit 1 Low-pressure Turbine Upgrade
Notification	Transmittal SPG-CNP-167	8/28/03	DC Cook Unit 1 Torsional Issue Notification
Procedure	12-EHP-5043-OAR-001	6	Owner's Acceptance Review
Procedure	12-EHP-2291-RIS-001	5	Engineering Risk Analysis
Procedure	PMP-5040-MOD-007	7	Engineering Modifications
Procedure	PMP-5040-MOD-007		Engineering Modifications
Procedure	PMP-5040-MOD-010	7	Field Change Notices
Procedure	PMP-5040-MOD-010		Field Change Notices
Procedure	PMP-8100-PRJ-001	1	Conduct of Projects
Procedure	PMP-1060-RPA-001	1	Request for Project Authorization Process
Procedure	OHP-SP-286	0	Main Turbine Critical Speed Testing
Procedure	PMP-3140-MOD-001	8	Contract, Development, and Administration

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.10**

DOCUMENTS REVIEWED			
TYPE	DOC. #	DATE OR REV.	TITLE/DESCRIPTION
Siemens Presentation		9/6/2006	Rotor Torsional Issue.
Siemens Report	S32M7_105-15	2	Missile Probability Analysis
Siemens Report	0NGT04007646	11/7/06 – 11/21/2006	Startup and Balance After New LP Rotors ( <i>initial installation balancing of Unit 1 turbine</i> )
Siemens Report	0NGT0811701	3/25/08- 4/2/08	L-0 Blades NDE (Dyphenetraint testing of LP-B L-0 Blade tips)
Siemens Report	1NGT08011701	4/24/08- 4/29/08	LP Pedestal Fast Fourier Analysis Testing.
Siemens Report	0NGT08011701	3/24/08- 3/31/08	Vibration Analysis
Siemens Report	2NGT08012A77	4/25/08 – 5/05/08	Vibration Analysis
Siemens Report	0NGT08012A77	02/02/08 – 02/11/2008	Vibration
Siemens Report	EC-080MPC	4/11/08	DC Cook Critical Speed & Unbalance Response Studies
Siemens Report	S32M7 / 2005 / 10444	Rev.2	Torsional Studies for AEP DC Cook Unit #1 with 18m <sup>2</sup> LP Rotor Retrofit
Siemens Report	P11M2-07-029	2/22/07	Evaluation of BSSM – Testing of 18m <sup>2</sup> last stage blade row at DC Cook #1
Siemens Report	P11M7-06-10822	11/12/06	DC Cook Unit 1 – On-Line Torsional Response Test
Siemens Report	P11M7-06-10607	Revs. 1, 2 and 3	Mechanical Interface Report
Siemens Turbine Maintenance and Inspection Rec.	1.1.4-60100-11054/1		Steam Turbine Maintenance
Technical Procurement Specification		12/17/03	Low Pressure Turbine Rotor and Stationary Component Replacement
UFSAR	UFSAR – 14.1.3	21	Updated Final Safety Analysis Report
Work Package	TG No: TG6427.00	Rev. 1	Install L-0 Blades in The #2 (B) LP Rotor
Work Order	55323969 - 01	N//A	Stiffen U1 LP-B Bearing to Increase Natural Frequency

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.11**

**6.11 SAFETY CULTURE IMPACT REVIEW**

Safety Culture Cross Cutting Area	Safety Culture: Cross-Cutting Area Component	Safety Culture Definition	Did the CR Evaluation identify any of the following Cross-Cutting Area Components? (Y/N) Document the basis for identifying the safety culture Cross-Cutting Area Component as related or not.		Reference actions addressing any safety Cross-Cutting Area Component noted as yes.
			Y/N		
<b>Human Performance</b>	<b>Decision Making</b>	<b>Licensee decisions demonstrate that nuclear safety is an overriding priority.</b>	N	Appropriate use of risk analysis and decision making based on nuclear safety were demonstrated in modification risk analysis and IPTE. A significant lesson learned for the CNP is to also focus on controlling large consequences even for non-nuclear safety issues.	
	<b>Resources</b>	<b>The licensee ensures that personnel, equipment, procedures, and other resources are available and adequate to assure nuclear safety.</b>	N	Resource challenges were noted to the Turbine Replacement Project management but were not a challenge to nuclear safety.	
	<b>Work Control</b>	<b>The licensee plans and coordinates work activities, consistent with nuclear safety.</b>	N	No work control issues were noted relative to this event.	
	<b>Work Practices</b>	<b>Personnel work practices support human performance.</b>	N	No work practice issues were noted relative to this event.	
<b>Problem Identification &amp; Resolution</b>	<b>Corrective Action Program</b>	<b>The licensee ensures that issues potentially impacting nuclear safety are promptly identified, fully evaluated, and that actions taken to address safety issues in a timely manner, commensurate with their significance.</b>	N	CRs were used to identify and correct that turbine was near 120 Hz in November 2006.	
	<b>Operating Experience</b>	<b>The licensee uses operating experience information, including vendor recommendations and internally generated lessons learned, to support plant safety.</b>	N	Although OE use may be improved, OE was used in the project to improve performance.	

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.11**

Safety Culture Cross Cutting Area	Safety Culture: Cross-Cutting Area Component	Safety Culture Definition	Did the CR Evaluation identify any of the following Cross-Cutting Area Components? (Y/N) Document the basis for identifying the safety culture Cross-Cutting Area Component as related or not.		Reference actions addressing any safety Cross-Cutting Area Component noted as yes.
			Y/N		
	<b>Self &amp; Independent Assessment</b>	<b>The licensee conducts self- and independent assessments of their activities and practices, as appropriate, to assess performance and identify areas for improvement.</b>	N	<p>No evidence that self or independent assessment was made of the Turbine Replacement Project or turbine supplier. The turbine supplier was assessed by the Turbine Replacement Project team.</p> <p>Procurement was QA-standard grade. Under these provisions vendor oversight is not normally required.</p> <p>Benchmarking was done on turbine replacement by the Project Manager.</p> <p>Excellence Plans existed to improve projects performance during this time frame (Refer to eCAP 05298107 and 06096041)</p>	
<b>Safety Conscious Work Environment</b>	<b>Environment for Raising Concerns</b>	<b>An environment exists in which employees feel free to raise concerns both to their management and/or the NRC without fear of retaliation, and employees are encouraged to raise such concerns.</b>	N	<p>Siemens was able to raise and resolve concerns with system natural frequency being close to 120hz.</p> <p>CNP were comfortable raising concerns. CNP raised concerns with the safety of off-line torsional testing of the GE Turbine Generator proposed by Siemens. The concerns were resolved by using a safer on-line torsional test.</p> <p>Employee Concerns, Differing Professional Opinions and Exit Interviews were screened by ECP and PA personnel and no concerns relative to the turbine blade repair were identified.</p>	
	<b>Preventing, Detecting &amp; Mitigating Perceptions of Retaliations</b>	<b>A policy for prohibiting harassment and retaliation for raising nuclear safety concerns exists and is consistently enforced.</b>	N	No evidence of retaliation. Policy Exists.	
<b>Conclusion:</b> There was no evidence of a Safety Culture impact in this event.					

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.12**

**6.12 GLOSSARY**

<b>AEP</b>	American Electric Power – Parent Company of Indian & Michigan Power (I&M) licensee for D.C. Cook Nuclear Plant
<b>Aero Elastic Flutter</b>	Twisting of a blade
<b>asynchronous vibration</b>	Blade response to dynamic forces at frequencies that are not harmonics of shaft rotating speed, but involve a more direct interaction of the flow around the blade airfoil.
<b>beach marking</b>	A distinctive pattern of lines resulting from fatigue cracking similar to lines on a beach from wave action.
<b>CNP</b>	Cook Nuclear Plant
<b>dynamic stress</b>	Consequence of the blade-disk system response to synchronous or asynchronous forces present in the steam flow that result in vibration of the modes at their natural frequencies.
<b>EPRI</b>	Electric Power Research Institute
<b>fatigue</b>	Damage mechanisms associated with cycles of start-stop operation (low) and vibration (high) where loading and unloading result in the accumulation of permanent damage to the material.
<b>fractography</b>	The study of blade fracture surfaces with the intent to determine the origin of the crack and evidence of the various damage mechanisms that might have been experienced prior to failure.
<b>High Cycle Fatigue (HCF)</b>	Damage mechanism associated with cycles of vibration where loading and unloading result in the accumulation of permanent damage.
<b>incubation</b>	A generic term designating the period of service that precedes the formation of an original crack on a microscopic (grain boundary) level in a blade.
<b>initiation</b>	Generic term designating the period of service where a crack has first formed in a pit, erosion notch, void, or other discontinuity found on the blade, or in a localized stress raiser.
<b>ksi</b>	kips per square inch – A unit of Stress Measurement
<b>Loss of Mass</b>	A component or part of component was lost from the rotating elements of the turbine.
<b>Low Cycle Fatigue (LCF)</b>	Damage mechanism associated with start-stop cycles where loading and unloading result in the accumulation of permanent damage.
<b>mils</b>	A unit of vibration measurement
<b>Mode</b>	The stationary vibration patterns of an elastic component. May be referred to as node in some texts.
<b>Natural Frequency</b>	The frequency at which a component naturally vibrates when struck. (e.g. a tuning fork vibrates at it's natural frequency)
<b>NDE</b>	nondestructive evaluation/nondestructive examination
<b>propagation</b>	A generic term designating the period of service in which an initial crack advances through the material at a deliberate, predictable rate after exceeding the material's stress intensity threshold.
<b>Radial Vibrations</b>	Vibrations associated with movement of the shaft in the radial direction
<b>Resonance</b>	A vibration of large amplitude in a mechanical or electrical system caused

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.12**

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	by periodic stimulus.
<b>rpm</b>	Revolutions per minute – a unit of rotational speed measurement.
<b>rupture</b>	A generic term designating the period of service in which a crack reaches the fracture toughness of the material and a catastrophic separation of the blade is predicted.
<b>Torsional Vibrations</b>	Vibrations associated with the twisting of the shaft line.

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.13**

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### 6.13 CARB COMMENTS

On 3/12/09, CARB #466 concurred with the root cause presentation with a Score of “3.5” and the following comments:

1. Cross reference any action in the report that are tracking recovering margin.
  - a. Margin recovery is identified in action 4.1.2
2. Provide supportive information in section 3.1 regarding why the halting of the BSSM at 95% power wasn't an influence on the event.
  - a. Revised page 10 and 50. Siemens is further evaluating the aeroelastic mechanism.
3. Page 9, a reference to EPRI 101437 is made regarding tolerances for root attachments, but there is no basis or conclusions provided regarding the reference.
  - a. Basis added on page 9.
4. Page 11, change the reference to work being scheduled during “U1C23” for stiffening the bearing supports to “prior to restart”.
  - a. Revised page 11
5. Page 11, revise the third sentence of the third paragraph as follows “These decisions were reasonable and prudent, *and in-line with best industry practices*, based on the information...”
  - a. Revised page 11
6. Page 12, Section 3.2, provide the blade size for the Unit 2 Brown Boveri turbine blades.
  - a. Revised page 13
7. Page 12, Section 3.2, the feed pump turbine needs to be discussed in the Extent of Condition section.
  - a. Revised page 13
8. Page 13, provide clarification that the Unit 1 Plant Air Compressor was unavailable due to the loss of power. Ensure that the text is in-line with the text in the fire water header pipe coupling separation root cause AR 00838930-1.
  - a. Revised on page 14
9. Page 14, paragraph 2, do not use the term “flying parts”. Provide specific examples of what was falling, e.g. insulation, etc.
  - a. Deleted flying parts on page 15.
10. Page 14, Section 3.3, provide more discussion of the potential for personal injury, and how fallen asbestos was dispositioned.
  - a. Revised Page 15
11. Overall, Section 3.3 was weak. Work with LOD Manager to strengthen the depth of the discussion.
  - a. Revised page 14 and 15
12. Page 14, Section 3.4, ensure that the discussions involving the damaged fire header are in alignment with the text in the fire water header pipe coupling separation root cause AR 00838930-1.
  - a. Revised page 15
13. CATPR 4.1.1., strike the word “manufacturing” from the CATPR.

**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.13**

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- a. Revised in Executive Summary and in section 4.1.2 and new 4.1.1
14. Add a CATPR action for the interim Unit 1 turbine “design and testing” and an action to track its certification. Dr. Waldo from PII will work with the team to create the actions wording.
  - a. Added 4.1.1 the action for certifications was already in section 4.1.4 (now 4.1.5)
15. Align the wording in Section 4.2 Extent of Condition, with the body of the report.
  - a. Revised
16. Modify action 4.4.1.1 to clarify that the action is created to revise the Design and Modification procedure.
  - a. Revised to state project and design processes.
17. Specify that action 4.5.2 applies to the Unit 1 Siemens turbine only.
  - a. Revised
18. Revise action 4.5.3 to state “Develop a Turbine Preventive Maintenance Plan and PM activities *to align the frequency with the effectiveness review.*”
  - a. Revised
19. Provide the CARB Chair with the assignment numbers that are tracking resolution of the No. 5 Bearing issues.
  - a. Was discussed on page 51 of the report provided to CARB. Action added to section 4.5.
20. The root cause team will show the CARB Board which recommendations from the PII report as referenced on page 67 will be included as actions to the AEP root cause report. The CARB will consist of members of CARB #466 (S. Lies, R. Keppeler, R. Crane, V. Woods, and L. Bush).
  - a. Cross references to PII actions included in action section. Two actions added.
21. The effectiveness review plan needs to encompass the interim turbine project also.
  - a. Revised
22. Section 5.4.1. bullet No. 2, needs to be revise to provide a more detailed timeline of interim effectiveness reviews that are to be provided to CARB regarding the performance of the interim replacement turbine.
  - a. Revised
23. Modify Section 5.4.2 statement “...operates without incident” to state “...operate within success criteria”.
  - a. Revised
24. Section 5.4.2, provide specific dates or milestone statements for bullets 1 and 2.
  - a. Milestones included
25. Page 75, Attachment 6.11, strike the “Needs Actions” from the Reference Actions column for Area Component – Self and Independent Assessment.
  - a. Revised, page 76
26. Page 75, Attachment 6.11, Clarify the response to the Area Component for Environment for Raising Concerns to state that CNP personnel were comfortable raising concerns.
  - a. Revised, page 76

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**UNIT 1 MAIN TURBINE GENERATOR TRIP (CR) 00838732, ATTACHMENT 6.13**

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CARB Chair S. Lies will be the CARB sponsor and will provide concurrence with the resolution of the CARB comments.

DIRECT TESTIMONY OF DAVID L. HILLE  
ON BEHALF OF  
INDIANA MICHIGAN POWER COMPANY  
2009 PSCR RECONILIATION CASE

1 Q. Please state your name and business address.

2 A. My name is David L. Hille. My business address is One Summit Square, P. O.  
3 Box 60, Fort Wayne, Indiana 46801.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Indiana Michigan Power Company (I&M or Company) as  
6 Principal Regulatory Consultant in the Regulatory Services Department.

7 Q. Please briefly describe your educational and business experience.

8 A. I graduated from Ball State University in 1983 with a Bachelor of Science  
9 Degree in Accounting. After graduating in 1983, I joined American Electric  
10 Power Service Corporation (AEPSC) as an Auditor Assistant performing  
11 operational reviews of the area offices of I&M and Michigan Power Company  
12 (MPCo). As an internal auditor, I became experienced in the process of  
13 inspecting and analyzing data and then drawing conclusions and reporting  
14 findings based on the data inspected.

15 In May 1986, I accepted a position in I&M's Rates and Tariffs  
16 Department as a Rate Analyst. My duties included preparing data used in  
17 formal and informal rate proceedings that included various monthly, quarterly,  
18 and annual fuel cost-related filings.

19 In September 1991, I was named to Senior Rate Analyst. My duties in  
20 this position involved the accumulation, documentation, presentation, and  
21 review of data for various rate proceedings. In January 1996, I became

1 Manager of Rates and Regulations responsible for matters concerning various  
2 rate proceedings and fuel filings and the supervision of the preparation of  
3 various reports or studies. The department and my position were  
4 subsequently changed to Regulatory Services and Senior Regulatory  
5 Consultant, respectively, and I have since been named Principal Regulatory  
6 Consultant but my central responsibilities remain the same. In particular, I am  
7 responsible for reviewing I&M's monthly Power Supply Cost Recovery (PSCR)  
8 reports and coordinating the preparation and filing of I&M's annual PSCR Plan  
9 and Reconciliation Cases. I directly report to the Director of Regulatory  
10 Services.

11 Q. Have you previously testified in any regulatory proceedings?

12 A. Yes. I testified before the Michigan Public Service Commission (Commission)  
13 in I&M's 2004, 1997, and 1996 PSCR Plan Cases and 1997 and 1996 PSCR  
14 Reconciliation Cases. I also submitted testimony to the Commission in I&M's  
15 2008 thru 2004, 1998, 1995, and 1994 PSCR Reconciliation Cases and I&M's  
16 2010 thru 2005, 2000, 1999, 1998, and 1995 PSCR Plan Cases. In addition, I  
17 have testified before the Indiana Utility Regulatory Commission in I&M's fuel  
18 cost proceedings.

19 Q. What is the purpose of your testimony in this proceeding?

20 A. The purpose of my testimony is to present the reconciliation of revenues  
21 collected from customers located in I&M's St. Joseph and Three Rivers Rate  
22 Areas pursuant to the PSCR factors billed in 2009, and the allowance for cost

1 of power supply included in base rates, with the amounts actually expensed  
2 and included in the cost of power supply for the period January through  
3 December 2009. I will support the calculation of interest in accordance with  
4 provisions outlined in the PSCR statute. In addition, the total balances I&M  
5 requests to be rolled in to future costs will be detailed, and I will also address  
6 the differences between the projected costs included in the 2009 PSCR Plan  
7 and actual 2009 costs for the respective rate areas.

8 Q. What exhibits are you sponsoring in this proceeding?

9 A. I am sponsoring four exhibits in this proceeding that are identified as Exhibits  
10 IM-5 through IM-8. Exhibits IM-5 and IM-6 relate to the St. Joseph Rate Area  
11 and Exhibits IM-7 and IM-8 are for the Three Rivers Rate Area.

12 Q. Were these exhibits either prepared by you or under your supervision and  
13 direction?

14 A. Yes.

15 Q. Does I&M's 2009 PSCR Reconciliation separately address the two I&M rate  
16 areas?

17 A. Yes. Effective February 29, 1992, MPCo was merged into I&M. In  
18 accordance with the Commission's December 5, 1991, Order Approving  
19 Settlement Agreement in Case No. U-9912, which approved the merger, I&M  
20 was authorized to establish two rate areas for I&M's merged service territory.  
21 The Order provided that the I&M-St. Joseph Rate Area and the I&M-Three  
22 Rivers Rate Area (the former MPCo retail service area) PSCR costs should

1 each continue to be monitored on a stand-alone basis. Consequently, this  
2 reconciliation filing separately addresses the St. Joseph and Three Rivers  
3 Rate Areas.

4 Q. Please summarize I&M's proposed 2009 PSCR Reconciliation for each rate  
5 area.

6 A. For the St. Joseph Rate Area, I&M experienced an under-recovery of PSCR  
7 costs for 2009 totaling \$3,566,251. I&M proposes to collect this under-  
8 recovery and associated interest totaling \$3,433,990 by rolling this amount into  
9 its 2010 PSCR Plan year costs.

10 For the Three Rivers Rate Area, I&M experienced an under-recovery of  
11 PSCR costs for 2009 totaling \$1,007,677. I&M proposes to collect this under-  
12 recovery and associated interest totaling \$1,025,038 by rolling this amount into  
13 its 2010 PSCR Plan year costs.

14 ST. JOSEPH RATE AREA

15 Q. Would you please describe the St. Joseph Rate Area exhibits?

16 A. Yes. Exhibit IM-5, consisting of two pages, shows the reconciliation of PSCR  
17 revenues collected in the St. Joseph Rate Area with actual PSCR costs  
18 incurred for the period January through December 2009.

19 Page 1 of 2, entitled "Indiana Michigan Power Company, St. Joseph  
20 Rate Area, Reconciliation of PSCR Revenues Recorded with Actual Allowable  
21 PSCR Costs, January 2009–December 2009," details the monthly and total  
22 revenues recorded pursuant to the PSCR factor and allowance for cost of

1 power supply included in base rates, the costs of power supply actually  
2 expensed, and the resultant monthly over/(under) recoveries for the period  
3 January through December 2009. This exhibit shows that total St. Joseph  
4 Rate Area PSCR revenues recorded during 2009 were \$18,674,819 and that  
5 the total cost of power supply actually expensed in 2009 was \$26,498,083,  
6 resulting in an under-recovery of \$7,823,264.

7 Page 2 of 2, entitled "Indiana Michigan Power Company, St. Joseph  
8 Rate Area, Interest Calculation, January 2009–December 2009," shows the  
9 calculation of interest on the monthly over/(under) recoveries. This page  
10 shows the calculation of interest to be credited by I&M in the amount of  
11 \$132,261 for the period January through December 2009. As noted on this  
12 page, the January beginning balance reflects the outstanding balance  
13 approved in I&M's 2008 PSCR Reconciliation, Case No. U-15416-R.

14 Q. Would you please explain the other St. Joseph Rate Area exhibit you are  
15 sponsoring?

16 A. Exhibit IM-6, page 1 of 2, entitled "Indiana Michigan Power Company, St.  
17 Joseph Rate Area, Comparison of Monthly Actual with Monthly Projected  
18 PSCR Costs, January 2009–December 2009," is a comparison of the  
19 projected monthly per unit costs included in the 2009 PSCR Plan and the  
20 actual 2009 monthly per unit costs. Page 2 of 2, entitled "Indiana Michigan  
21 Power Company, St. Joseph Rate Area, Comparison of Actual with Projected  
22 PSCR Costs, January 2009–December 2009," provides a comparison of the

1 actual annual fuel and purchased and interchange power costs in 2009 with  
2 the level of costs originally projected for 2009.

3 Q. What PSCR factor was billed in the St. Joseph Rate Area during 2009?

4 A. A PSCR factor of 6.62 mills per kWh was billed in the St. Joseph Rate Area  
5 during the billing months of January through December 2009. The  
6 Commission's March 18, 2009 Order Approving Settlement Agreement in  
7 I&M's 2009 PSCR Plan approved a PSCR factor up to the 6.62 mills per kWh.  
8 When the 2009 PSCR Plan Case factor of 6.62 mills per kWh is combined with  
9 the 3.33 mills per kWh of PSCR costs included in I&M's base rates, a total  
10 PSCR cost level of 9.95 mills per kWh for the St. Joseph Rate Area results.

11 Q. Please describe the reconciliation of PSCR costs with revenues for the period  
12 January through December 2009 as shown on Exhibit IM-5 page 1 of 2.

13 A. The PSCR costs shown on page 1 of 2, Column 4, reflect actual monthly total  
14 Company per unit costs appropriate for recovery through the PSCR clause.  
15 The total PSCR-related costs recoverable pursuant to the PSCR factor and  
16 base rates (Column 7) were determined by multiplying the per unit costs  
17 (Column 4) by the St. Joseph Rate Area kWh subject to the PSCR factor  
18 (Column 5). The revenues that were actually collected, pursuant to the PSCR  
19 factors and allowance for cost of power supply included in base rates (Column  
20 6), were determined by multiplying the total PSCR factors (Column 3) by the  
21 St. Joseph Rate Area kWh subject to the PSCR factor (Column 5). The  
22 over/(under) recoveries by month are shown in Column 8.

1 Q. Do the actual total Company per unit costs include those revenues and costs  
2 discussed by Witness Ondayko?

3 A. Yes.

4 Q. What interest rates were applied to monthly over/(under) recoveries during  
5 2009?

6 A. During the months I&M experienced cumulative, average over-recovered  
7 balances, January through July, as shown on Exhibit IM-5, page 2 of 2,  
8 Column 5, I&M used the monthly equivalent of a 13.00% annual rate, which is  
9 the rate of return on common equity approved by the Commission in Case No.  
10 U-9656 (I&M's last general rate case). During the months I&M experienced  
11 cumulative, average under-recovered balances, August through December,  
12 I&M used the monthly average short-term debt rate to calculate interest.

13 Q. What is the total amount of principal and interest which I&M is proposing to  
14 collect from St. Joseph Rate Area customers as a result of the 2009 PSCR  
15 under-recovery?

16 A. As shown on Exhibit IM-5, page 2 of 2, the total amount to be collected from  
17 the St. Joseph Rate Area is \$3,433,990.

18 Q. How does I&M propose to charge this amount?

19 A. I&M filed its 2010 PSCR Plan on September 30, 2009, in Case No. U-16046  
20 and in that filing proposed to charge a net under-recovery by rolling an  
21 estimated 2009 under-recovery amount into its 2010 PSCR Plan year costs.  
22 In that filing the Company requested approval of a 2010 PSCR Plan year

1 factor that included forecast plan year costs, and a roll in of the 2009 PSCR  
2 estimated under-recovery. Application of the 2010 Plan year factor to current  
3 year Michigan retail electric sales should produce PSCR revenues that are  
4 sufficient to provide for recovery of 2010 PSCR costs plus the estimated 2009  
5 PSCR under-recovery from Michigan customers.

6 Q. What was the estimated 2009 under-recovery amount included in I&M's 2010  
7 PSCR Plan filing, Case No. U-16046?

8 A. I&M estimated a 2009 PSCR under-recovery of \$3,613,522 in the Company's  
9 2010 PSCR Plan. At that time seven months of actual data and five months of  
10 forecasted data were available. The actual 2009 PSCR under-recovery  
11 amount is \$3,433,990 as presented in this reconciliation filing.

12 Q. Has the Commission issued an order in Case No. U-16046?

13 A. Not at the time of this filing.

14 Q. What is I&M requesting the Commission approve in this PSCR reconciliation  
15 filing?

16 A. I&M is requesting the Commission approve the reconciliation of its 12-month  
17 power supply costs, revenues, and interest for 2009, and determine that the  
18 power supply costs as presented in this reconciliation filing were reasonably  
19 and prudently incurred. I&M is also requesting authorization to roll in the net  
20 actual under-recovered amount of \$3,433,990.

1 Q. How do the actual 2009 monthly PSCR costs for the St. Joseph Rate Area  
2 compare to the monthly costs that were projected in I&M's 2009 PSCR Plan  
3 Case?

4 A. Exhibit IM-6, page 1 of 2, provides the actual and projected per unit PSCR  
5 costs by month for the year 2009. Exhibit IM-6, page 2 of 2, compares the  
6 actual costs with projected costs at I&M's generating plants and for purchased  
7 and interchange power components. As shown in the exhibit, the overall total  
8 per unit generation cost of 14.10 mills per kWh was 0.08 mills per kWh higher  
9 than projected.

10 Page 2 of 2 of Exhibit IM-6 also contains a comparison of actual and  
11 projected purchased power and interchange power components. This  
12 comparison includes power purchases by I&M, the level of interchange power  
13 to and from the AEP System Pool, and the level of non-firm system sales to  
14 non-affiliated utilities.

15 Q. Do the purchased power costs in this case stem from reasonable and prudent  
16 decisions?

17 A. Yes, the costs reflected in my exhibits are consistent with I&M's PSCR Plan  
18 and result from the operation of the AEP System, which dispatches resources  
19 in economic order, and operation of the AEP Interconnection Agreement,  
20 which allocates the least costly power to serve its internal customers and the  
21 most expensive power to external sales.

1 Q. Based on that understanding and your review of the costs, is it your opinion  
2 the purchased power costs in this case are reasonable and prudent?

3 A. Yes.

4 Q. Have you prepared an exhibit to evaluate the variations between the actual  
5 and forecasted 2009 PSCR costs for the Three Rivers Rate Area?

6 A. Yes. To evaluate the variance between the actual and forecasted 2009 St.  
7 Joseph Rate Area PSCR costs, I have prepared Exhibit IM-6, page 2 of 2.  
8 This exhibit provides a comparison of the major cost components that  
9 comprise I&M's St. Joseph Rate Area PSCR clause fuel costs. As shown in  
10 the exhibit, I&M's actual and projected overall PSCR costs were very similar.  
11 The under-recovery is a result of the actual beginning over-recovery balance  
12 being less than projected in the 2009 PSCR Plan case.

13 THREE RIVERS RATE AREA

14 Q. Turning now to the Three Rivers Rate Area, would you please identify the  
15 exhibits you are sponsoring?

16 A. Yes. Exhibit IM-7, consisting of two pages, shows the reconciliation of PSCR  
17 revenues collected in the Three Rivers Rate Area with actual PSCR costs  
18 incurred for the period January through December 2009.

19 Page 1 of 2, entitled "Indiana Michigan Power Company, Three Rivers  
20 Rate Area, Reconciliation of PSCR Revenues Recorded with Actual Allowable  
21 PSCR Costs, January 2009-December 2009," details the monthly and total  
22 revenues recorded pursuant to the PSCR factor and allowance for cost of

1 power supply included in base rates, the costs of power supply actually  
2 expensed, and the resultant monthly over/(under) recoveries for the period  
3 January through December 2009. This exhibit shows the total Three Rivers  
4 Rate Area PSCR revenues recorded during 2009 were \$16,995,837 and that  
5 the total cost of power supply actually expensed in 2009 was \$15,839,148,  
6 resulting in an over-recovery of \$1,156,689.

7 Page 2 of 2, entitled "Indiana Michigan Power Company, Three Rivers  
8 Rate Area, Interest Calculation, January 2009-December 2009," shows the  
9 calculation of interest on the monthly over/(under) recoveries. This page  
10 shows the calculation of interest to be collected by I&M in the amount of  
11 \$17,361 for the period January through December 2009. As noted on this  
12 page, the January beginning balance reflects the outstanding balance  
13 approved in I&M's 2008 PSCR Reconciliation, Case No. U-15416-R.

14 Q. Would you please explain the other Three Rivers Rate Area exhibit you are  
15 sponsoring?

16 A. Yes. I am also sponsoring Exhibit IM-8, page 1 of 2, entitled "Indiana Michigan  
17 Power Company, Three Rivers Rate Area, Comparison of Monthly Actual with  
18 Monthly Projected PSCR Costs, January 2009–December 2009," and Exhibit  
19 IM-8, page 2 of 2, entitled "Indiana Michigan Power Company, Three Rivers  
20 Rate Area, Comparison of Actual with Projected PSCR Costs, January 2009-  
21 December 2009."

22 Q. What PSCR factor was billed in the Three Rivers Rate Area during 2009?

1 A. I&M billed a PSCR factor of 7.38 mills per kWh in the Three Rivers Rate Area  
2 during the billing months of January through December 2009. The 7.38 mills  
3 per kWh was the PSCR Plan factor proposed by I&M and approved by the  
4 Commission in its Order Approving Settlement Agreement dated March 18,  
5 2009 in I&M's 2009 PSCR Plan. When the 2009 Plan Case factor is combined  
6 with the 10.30 mills per kWh of PSCR costs included in I&M's base rates, a  
7 total PSCR cost level of 17.68 mills per kWh for the Three Rivers Rate Area  
8 results.

9 Q. Please describe the reconciliation of PSCR costs with revenues for the period  
10 January through December 2009, as shown in Exhibit IM-7, page 1 of 2.

11 A. The PSCR costs shown on page 1 of 2, Column 4, reflect actual monthly total  
12 Company per unit costs appropriate for recovery through the PSCR clause.  
13 The total PSCR-related costs recoverable pursuant to the PSCR factor and  
14 base rates (Column 7) were determined by multiplying the per unit costs  
15 (Column 4) by the Three Rivers Rate Area kWh subject to the PSCR factor  
16 (Column 5). The revenues that were actually collected, pursuant to the PSCR  
17 factors and allowance for cost of power supply included in base rates (Column  
18 6), were determined by multiplying the total PSCR factors (Column 3) by the  
19 Three Rivers Rate Area kWh subject to the PSCR factor (Column 5). The  
20 over/(under) recoveries by month are shown in Column 8.

21 Q. Do the actual total Company per unit costs include those revenues and costs  
22 discussed by Witness Ondayko?

1 A. Since the Three Rivers Rate Area PSCR is based on the FERC Net Energy  
2 Cost method, only fuel costs associated with the net energy requirement are  
3 included.

4 Q. What interest rates were applied to the monthly over/(under) recoveries during  
5 2009?

6 A. Since I&M experienced cumulative, average under-recovered balances during  
7 each month of 2009, as shown on Exhibit IM-7, page 2 of 2, Column 5, I&M  
8 used the monthly average short-term debt rate to calculate interest.

9 Q. What is the total amount of principal and interest which I&M is proposing to  
10 collect from Three Rivers Rate Area customers in this Reconciliation  
11 proceeding?

12 A. As shown on Exhibit IM-7, page 2 of 2, the total amount to be collected from  
13 the Three Rivers Rate Area is \$1,025,038.

14 Q. How does I&M propose to collect this amount?

15 A. I&M filed its 2010 PSCR Plan on September 30, 2009, in Case No. U-16046  
16 and in that filing proposed to collect a net under-recovery by rolling an  
17 estimated 2009 under-recovery amount into its 2010 PSCR Plan year costs.  
18 In that filing the Company requested approval of a 2010 PSCR Plan year  
19 factor that included forecast plan year costs, and a roll in of the 2009 PSCR  
20 estimated under-recovery. Application of the 2010 Plan year factor to current  
21 year Michigan retail electric sales should produce PSCR revenues that are  
22 sufficient to provide for recovery of 2010 PSCR costs less the estimated 2009

1 PSCR under-recovery to Three Rivers rate area customers. This methodology  
2 is consistent with the St. Joseph rate area.

3 Q. What was the estimated 2009 under-recovery amount included in I&M's 2010  
4 PSCR Plan filing, Case No. U-16046?

5 A. I&M estimated a 2009 PSCR under-recovery of \$1,228,451 in the Company's  
6 2010 PSCR Plan. At that time seven months of actual data and five months of  
7 forecasted data were available. The actual 2009 PSCR under-recovery  
8 amount is \$1,025,038 as presented in this reconciliation filing.

9 Q. Has the Commission issued an order in Case No. U-16046?

10 A. Not at the time of this filing.

11 Q. What is I&M requesting the Commission approve in this PSCR reconciliation  
12 filing?

13 A. I&M is requesting the Commission approve the reconciliation of its 12-month  
14 power supply costs, revenues, and interest for 2009, and determine that the  
15 power supply costs as presented in this reconciliation filing were reasonably  
16 and prudently incurred. I&M is also requesting authorization to roll in the net  
17 actual under-recovered amount of \$1,025,038.

18 Q. How do the actual 2009 monthly PSCR costs for the Three Rivers Rate Area  
19 compare to the monthly costs that were projected in the 2009 PSCR Plan  
20 Case?

21 A. Exhibit IM-8, page 1 of 2, compares the forecasted monthly per unit PSCR  
22 cost factors utilized in I&M's 2009 PSCR Plan, with the monthly per unit PSCR

1 costs actually experienced.

2 Q. Have you prepared an exhibit to evaluate the variations between the actual  
3 and forecasted 2009 PSCR costs for the Three Rivers Rate Area?

4 A. Yes. To evaluate the variance between the actual and forecasted 2009 Three  
5 Rivers Rate Area PSCR costs, I have prepared Exhibit IM-8, page 2 of 2. This  
6 exhibit provides a comparison of the major cost components that comprise  
7 I&M's Three Rivers Rate Area PSCR clause fuel costs. As shown in the  
8 exhibit, I&M's actual and projected overall PSCR costs were very similar. The  
9 under-recovery is a result of the actual beginning under-recovery balance  
10 being larger than projected in the 2009 PSCR Plan case.

11 Q. Does this complete your discussion of the PSCR costs and revenues for the  
12 Three Rivers Rate Area?

13 A. Yes.

14 Q. Did I&M experience any generating plant outages in excess of 90 consecutive  
15 days during 2009?

16 A. Yes. As described by Witness Joseph N. Jensen, I&M experienced an outage  
17 in excess of 90 days at Cook Nuclear Plant Unit 1.

18 Q. Has I&M made any adjustments to the actual PSCR costs as a result of the  
19 Cook Unit 1 outage?

20 A. Yes

21 Q. Please describe the adjustment to actual PSCR costs to reflect the impact of  
22 the Cook Unit 1 outage.

1 A. I&M's intent is to use insurance proceeds received under the Accidental  
2 Outage policy to reduce the increased PSCR costs, calculated on both a St.  
3 Joe and Three Rivers rate area PSCR basis, that result from the Cook Unit 1  
4 outage. The adjustment reflects insurance coverage for 2009. The  
5 adjustment modifies actual PSCR costs as if I&M would be receiving  
6 generation from Cook Unit 1. This additional generation was accounted for  
7 first removing any retained AEP Non-associated Cash Purchases and any  
8 Pool-Primary & Economy Purchases from the AEP System Pool and then  
9 increasing I&M Primary Energy Deliveries to the AEP System Pool. This  
10 adjustment results in I&M supplying its Net Energy Requirement at a lower  
11 cost.

12 Q. What was the effect of this adjustment?

13 A. I&M's PSCR costs on a Total Company St. Joe and Three Rivers basis were  
14 reduced by \$88,196,505 and \$71,284,454, respectively.

15 Q. Did I&M experience any other generating plant outages in excess of 90  
16 consecutive days during 2009?

17 A. Yes. Tanners Creek Unit 4 was out of service from September 8 through  
18 December 27.

19 Q. Was this outage projected in I&M's 2009 PSCR Plan Case?

20 A. Yes. The 2009 PSCR Plan Case projections assumed that Tanners Creek  
21 Unit 4 would be in a planned outage starting in September 2009 and continue  
22 through mid-November.

1 Q. Did I&M incur increased fuel costs during this period as a result of the outage?

2 A. No. I&M, as a member of the FERC-approved AEP Interconnection  
3 Agreement (Pool), both delivers and receives energy with the other AEP  
4 System Pool members. Whether or not higher costs are incurred as a result of  
5 a plant outage at a particular time is dependent upon whether I&M is selling or  
6 purchasing power to the AEP System Pool and the per unit cost of the unit  
7 which is out of service. For Tanners Creek 4, actual mills per kWh fuel costs  
8 while operating in 2009 were higher than both energy deliveries I&M made to  
9 the Pool and the energy receipts I&M purchased from the Pool during the  
10 Tanners Creek 4 full outage months. Therefore, an increase in overall fuel  
11 costs was not incurred by I&M as a result of the outage.

12 Q. In conclusion, is it your opinion that the St. Joseph and Three Rivers Rate  
13 Areas actual PSCR costs presented in your testimony were reasonable and  
14 prudent?

15 A. Yes. Based on the analysis included in my testimony and exhibits and the  
16 testimonies of Witnesses West and Bellville concerning fuel costs, Ondaiko  
17 regarding AEP operating in the PJM Regional Transmission Organization, and  
18 Jensen addressing the Cook Unit 1 outage, I&M's actual PSCR costs incurred  
19 in 2009 were reasonable and prudent.

20 Q. Does this conclude your pre-filed direct testimony?

21 A. Yes.

INDIANA MICHIGAN POWER COMPANY  
ST. JOSEPH RATE AREA  
RECONCILIATION OF PSCR REVENUES RECORDED WITH ACTUAL ALLOWABLE PSCR COSTS  
JANUARY 2009 - DECEMBER 2009

LINE NO	MONTH	TOTAL PSCR FACTOR AS BILLED (MILLS/KWH)	TOTAL PSCR ACTUAL COSTS (MILLS/KWH)	KWH SUBJECT TO FACTOR	TOTAL PSCR REVENUE (COL. 3 X 5) \$	RECOVERABLE PSCR COST (COL. 4 X 5) \$	OVER/(UNDER) RECOVERY (COL. 6 - 7) \$
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	JANUARY	9.95	15.57	197,822,203	1,968,331	3,080,092	(1,111,761)
2	FEBRUARY	9.95	13.44	184,876,400	1,839,520	2,484,739	(645,219)
3	MARCH	9.95	11.51	162,207,294	1,613,963	1,867,006	(253,043)
4	APRIL	9.95	17.00	148,323,179	1,475,816	2,521,494	(1,045,678)
5	MAY	9.95	13.67	133,199,021	1,325,331	1,820,831	(495,500)
6	JUNE	9.95	11.67	136,854,334	1,361,701	1,597,090	(235,389)
7	JULY	9.95	13.71	151,978,831	1,512,190	2,083,630	(571,440)
8	AUGUST	9.95	13.59	156,427,194	1,556,451	2,125,846	(569,395)
9	SEPTEMBER	9.95	12.15	156,556,284	1,557,735	1,902,159	(344,424)
10	OCTOBER	9.95	14.11	138,766,111	1,380,723	1,957,990	(577,267)
11	NOVEMBER	9.95	15.43	141,476,186	1,407,688	2,182,978	(775,290)
12	DECEMBER	9.95	17.07	168,378,917	1,675,370	2,874,228	(1,198,858)
13	TOTAL			1,876,865,954	18,674,819	26,498,083	(7,823,264)

INDIANA MICHIGAN POWER COMPANY  
ST. JOSEPH RATE AREA  
INTEREST CALCULATION  
JANUARY 2009 - DECEMBER 2009

<u>MONTH</u>	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)
	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>
(1)	<u>BEG. OF MO.</u>	<u>END OF MO.</u>	<u>AVERAGE</u>	<u>INTEREST RATE *</u>	<u>INTEREST</u>	
	(2)	(3)	(4)	(5)	(6)	(7)
	\$	\$	\$	\$	%	\$
JANUARY (1)	(1,111,761)	4,257,013	3,145,252	3,701,133	13.00%	40,096
FEBRUARY	(645,219)	3,145,252	2,500,033	2,822,643	13.00%	30,579
MARCH	(253,043)	2,500,033	2,246,990	2,373,512	13.00%	25,713
APRIL	(1,045,678)	2,246,990	1,201,312	1,724,151	13.00%	18,678
MAY	(495,500)	1,201,312	705,812	953,562	13.00%	10,330
JUNE	(235,389)	705,812	470,423	588,118	13.00%	6,371
JULY	(571,440)	470,423	(101,017)	184,703	13.00%	2,001
AUGUST	(569,395)	(101,017)	(670,412)	(385,715)	0.58%	(186)
SEPTEMBER	(344,424)	(670,412)	(1,014,836)	(842,624)	0.41%	(288)
OCTOBER	(577,267)	(1,014,836)	(1,592,103)	(1,303,470)	0.23%	(250)
NOVEMBER	(775,290)	(1,592,103)	(2,367,393)	(1,979,748)	0.19%	(313)
DECEMBER	(1,198,858)	(2,367,393)	(3,566,251)	(2,966,822)	0.19%	(470)
TOTAL	(7,823,264)		(3,566,251)			132,261
						Total under-recovery and interest
						(3,433,990)

(1) January beginning balance reflects the outstanding balance approved in I&M's 2008 PSCR Reconciliation, Case No. U-15416-R

\* Monthly interest rate is calculated by dividing column (6) by 12.

INDIANA MICHIGAN POWER COMPANY  
ST. JOSEPH RATE AREA  
COMPARISON OF MONTHLY ACTUAL WITH MONTHLY PROJECTED PSCR COSTS  
JANUARY 2009 - DECEMBER 2009

<u>MONTH</u>	<u>ACTUAL PSCR COSTS (MILLS/KWH)</u>	<u>PROJECTED PSCR COSTS (MILLS/KWH)</u>	<u>DIFFERENCE IN COSTS (MILLS/KWH)</u>
JANUARY	15.57	9.93	5.64
FEBRUARY	13.44	12.91	0.53
MARCH	11.51	11.89	(0.38)
APRIL	17.00	17.04	(0.04)
MAY	13.67	15.52	(1.85)
JUNE	11.67	13.35	(1.68)
JULY	13.71	11.46	2.25
AUGUST	13.59	11.12	2.47
SEPTEMBER	12.15	13.08	(0.93)
OCTOBER	14.11	18.60	(4.49)
NOVEMBER	15.43	19.38	(3.95)
DECEMBER	17.07	15.51	1.56
TOTAL	14.10	14.02	0.08

INDIANA MICHIGAN POWER COMPANY  
ST. JOSEPH RATE AREA  
COMPARISON OF ACTUAL WITH PROJECTED PSCR COSTS  
JANUARY 2009- DECEMBER 2009

<u>GENERATION</u>	<u>ACTUAL PSCR RELATED COSTS</u>			<u>PROJECTED PSCR RELATED COSTS</u>			<u>DIFFERENCE % OF PROJ. (MILLS/KWH)</u>
	<u>MWH</u>	<u>\$</u>	<u>MILLS/KWH</u>	<u>MWH</u>	<u>\$</u>	<u>MILLS/KWH</u>	
FOSSIL (EXCL CP&L SALE)	10,319,134	233,199,518	22.60	12,876,700	316,077,000	24.55	(7.94)
AFFILIATED TRANS EXCL.	0	(23,474,750)	N/A	0	(25,546,000)	N/A	N/A
NUCLEAR	8,326,391	64,198,942	7.71	16,038,000	115,597,000	7.21	6.93
POST 4/7/83 SPENT NUCLEAR FUEL	0	7,727,811	N/A	0	14,995,000	N/A	N/A
HYDRO	112,605	0	N/A	119,300	0	N/A	N/A
SO2 EMISSION ALLOWANCE COST	0	2,532,225	N/A	0	2,585,000	N/A	N/A
NOx EMISSION ALLOWANCE COST	0	12,909,920	N/A	0	3,970,000	N/A	N/A
CO2 EMISSION COST	0	238,229	N/A	0	1,177,000	N/A	N/A
Hg EMISSION COST	0	0	N/A	0	0	N/A	N/A
<b>TOTAL GENERATION</b>	<b>18,758,130</b>	<b>297,331,895</b>	<b>15.85</b>	<b>29,034,000</b>	<b>428,855,000</b>	<b>14.77</b>	<b>7.31</b>
<u>PURCHASES</u>							
AEG/ASSOC	6,574,494	238,148,454	36.22	6,374,900	231,931,000	36.38	(0.44)
OVEC	1,265,083	42,196,075	33.35	1,287,600	56,860,000	44.16	(24.48)
COGENERATION	1,586	22,018	13.88	0	0	N/A	N/A
WIND PURCHASES	241,409	13,616,245	56.40	302,100	16,621,000	55.02	
OTHER SYSTEM PURCHASES	2,769,442	127,753,240	46.13	1,512,800	97,918,000	64.73	(28.73)
<b>TOTAL PURCHASES</b>	<b>10,852,014</b>	<b>421,736,032</b>	<b>38.86</b>	<b>9,477,400</b>	<b>403,330,000</b>	<b>42.56</b>	<b>(8.69)</b>
<u>SYSTEM POOL RECEIVED</u>							
PRIMARY ENERGY RECEIVED	1,081,601	28,293,186	26.16	29,800	846,000	28.39	(7.85)
SYSTEM SALES RECEIVED	2,043,008	68,889,402	33.72	4,857,700	210,028,000	43.24	(22.02)
SPECIAL SERVICE CUSTOMERS	10,056	753,592	74.94	0	0	N/A	N/A
<b>TOTAL SYSTEM POOL RECEIVED</b>	<b>3,134,665</b>	<b>97,936,180</b>	<b>31.24</b>	<b>4,887,500</b>	<b>210,874,000</b>	<b>43.15</b>	<b>(27.60)</b>
<u>SYSTEM POOL DELIVERED</u>							
PRIMARY ENERGY DELIVERED	(3,762,848)	(78,553,485)	(20.88)	(5,727,400)	(108,942,000)	(19.02)	9.78
SYSTEM SALES DELIVERED	(1,065,075)	(46,359,894)	(43.53)	(5,411,000)	(216,898,000)	(40.08)	8.61
CAPACITY SETTLEMENT CREDITS	0	(73,210,918)	N/A	0	(29,567,000)	N/A	N/A
BOOKOUTS	0	(16,149,950)	N/A	0	0	N/A	N/A
SPECIAL SERVICE CUSTOMERS	(20,061)	(1,418,190)	(70.69)	0	0	N/A	N/A
<b>TOTAL SYSTEM POOL DELIVERED</b>	<b>(4,847,984)</b>	<b>(215,692,437)</b>	<b>(44.49)</b>	<b>(11,138,400)</b>	<b>(355,407,000)</b>	<b>(31.91)</b>	<b>39.42</b>
<u>NON-FIRM SALES</u>							
NON-FIRM SALES	(4,304,617)	(200,982,945)	(46.69)	(6,137,700)	(342,948,000)	(55.88)	(16.45)
NON-OPERATING AUX.	(140,132)	0	N/A	(78,000)	0	N/A	N/A
NUCLEAR OUTAGE ADJUSTMENT	0	(88,196,505)	N/A	0	0	N/A	N/A
<b>NET ENERGY REQUIREMENT</b>	<b>23,452,076</b>	<b>312,132,220</b>	<b>13.30</b>	<b>26,044,800</b>	<b>344,704,000</b>	<b>13.23</b>	<b>0.53</b>
<b>NET ENERGY REQUIREMENT WITH 6% LOSS FACTOR</b>			<b>14.10</b>			<b>14.02</b>	

N/A - NOT APPLICABLE

INDIANA MICHIGAN POWER COMPANY  
THREE RIVERS RATE AREA  
RECONCILIATION OF PSCR REVENUES RECORDED WITH ACTUAL ALLOWABLE PSCR COSTS  
JANUARY 2009 - DECEMBER 2009

LINE NO	MONTH	TOTAL	TOTAL	KWH SUBJECT TO FACTOR	TOTAL PSCR	RECOVERABLE	OVER/(UNDER)
		PSCR FACTOR AS BILLED (MILLS/KWH)	PSCR ACTUAL COSTS (MILLS/KWH)		REVENUE (COL. 3 X 5)	PSCR COSTS (COL. 4 X 5)	RECOVERY (COL. 6 - 7)
(1)	(2)	(3)	(4)	(5)	(6) \$	(7) \$	(8) \$
1	JANUARY	17.680	17.741	87,420,402	1,545,593	1,550,925	(5,332)
2	FEBRUARY	17.680	17.775	82,255,878	1,454,284	1,462,098	(7,814)
3	MARCH	17.680	15.748	74,686,060	1,320,449	1,176,156	144,293
4	APRIL	17.680	20.234	76,573,494	1,353,819	1,549,388	(195,569)
5	MAY	17.680	16.396	71,612,392	1,266,107	1,174,157	91,950
6	JUNE	17.680	16.502	73,901,819	1,306,584	1,219,528	87,056
7	JULY	17.680	15.778	82,819,019	1,464,240	1,306,718	157,522
8	AUGUST	17.680	16.158	86,404,210	1,527,626	1,396,119	131,507
9	SEPTEMBER	17.680	14.443	84,893,660	1,500,920	1,226,119	274,801
10	OCTOBER	17.680	14.807	80,069,739	1,415,633	1,185,593	230,040
11	NOVEMBER	17.680	15.110	74,897,024	1,324,179	1,131,694	192,485
12	DECEMBER	17.680	17.030	85,769,401	1,516,403	1,460,653	55,750
13	TOTAL			961,303,098	16,995,837	15,839,148	1,156,689

INDIANA MICHIGAN POWER COMPANY  
THREE RIVERS RATE AREA  
INTEREST CALCULATION  
JANUARY 2009 - DECEMBER 2009

<u>MONTH</u>	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	OVER/(UNDER)	
	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	<u>RECOVERY</u>	
(1)	<u>BEG. OF MO.</u>	<u>END OF MO.</u>	<u>AVERAGE</u>	<u>INTEREST RATE *</u>	<u>INTEREST</u>	
	(2)	(3)	(4)	(5)	(6)	
	\$	\$	\$	\$	%	
	(7)				\$	
JANUARY (1)	(5,332)	(2,164,366)	(2,169,698)	(2,167,032)	1.94%	(3,503)
FEBRUARY	(7,814)	(2,169,698)	(2,177,512)	(2,173,605)	1.78%	(3,224)
MARCH	144,293	(2,177,512)	(2,033,219)	(2,105,366)	1.39%	(2,439)
APRIL	(195,569)	(2,033,219)	(2,228,788)	(2,131,004)	1.19%	(2,113)
MAY	91,950	(2,228,788)	(2,136,838)	(2,182,813)	0.95%	(1,728)
JUNE	87,056	(2,136,838)	(2,049,782)	(2,093,310)	0.70%	(1,221)
JULY	157,522	(2,049,782)	(1,892,260)	(1,971,021)	0.66%	(1,084)
AUGUST	131,507	(1,892,260)	(1,760,753)	(1,826,507)	0.58%	(883)
SEPTEMBER	274,801	(1,760,753)	(1,485,952)	(1,623,353)	0.41%	(555)
OCTOBER	230,040	(1,485,952)	(1,255,912)	(1,370,932)	0.23%	(263)
NOVEMBER	192,485	(1,255,912)	(1,063,427)	(1,159,670)	0.19%	(184)
DECEMBER	55,750	(1,063,427)	(1,007,677)	(1,035,552)	0.19%	(164)
TOTAL	1,156,689		(1,007,677)			(17,361)
Total under-recovery and interest						<u>(1,025,038)</u>

(1) January beginning balance reflects the outstanding balance approved in I&M's 2008 PSCR Reconciliation, Case No. U-15416-R

\* Monthly interest is calculated by dividing column (6) by 12.

INDIANA MICHIGAN POWER COMPANY  
THREE RIVERS RATE AREA  
COMPARISON OF MONTHLY ACTUAL WITH MONTHLY PROJECTED PSCR COSTS  
JANUARY 2009 - DECEMBER 2009

<u>MONTH</u>	<u>ACTUAL PSCR COSTS (MILLS/KWH)</u>	<u>PROJECTED PSCR COSTS (MILLS/KWH)</u>	<u>DIFFERENCE IN COSTS (MILLS/KWH)</u>
JANUARY	17.74	15.94	1.80
FEBRUARY	17.78	16.23	1.55
MARCH	15.75	16.04	(0.29)
APRIL	20.23	18.16	2.07
MAY	16.40	15.65	0.75
JUNE	16.50	16.17	0.33
JULY	15.78	16.71	(0.93)
AUGUST	16.16	16.68	(0.52)
SEPTEMBER	14.44	15.98	(1.54)
OCTOBER	14.81	19.01	(4.20)
NOVEMBER	15.11	19.21	(4.10)
DECEMBER	17.03	17.57	(0.54)
TOTAL	16.47	16.92	(0.45)

INDIANA MICHIGAN POWER COMPANY  
THREE RIVERS RATE AREA  
COMPARISON OF ACTUAL WITH PROJECTED PSCR COSTS  
JANUARY 2009- DECEMBER 2009

GENERATION	ACTUAL PSCR RELATED COSTS			PROJECTED PSCR RELATED COSTS			DIFFERENCE % OF PROJ. (MILLS/KWH)
	MWH	\$	MILLS/KWH	MWH	\$	MILLS/KWH	
FOSSIL (EXCL CP&L SALE)	10,319,134	233,199,518	22.60	12,876,700	316,077,000	24.55	(7.94)
NUCLEAR	8,326,391	64,198,942	7.71	16,038,000	115,597,000	7.21	6.93
POST 4/7/83 SPENT NUCLEAR FUEL	0	7,727,811	N/A	0	14,995,000	N/A	N/A
HYDRO	112,605	0	N/A	119,300	0	N/A	N/A
TOTAL GENERATION	18,758,130	305,126,271	16.27	29,034,000	446,669,000	15.38	5.79
<u>INTER-CO RECEIPTS</u>							
POOL - PRIMARY & ECONOMY	1,005,342	24,604,206	24.47	29,800	724,000	24.30	0.70
AEG	6,552,023	134,158,671	20.48	6,374,900	129,789,000	20.36	0.59
OVEC	1,265,083	25,405,415	20.08	1,287,600	23,639,000	18.36	9.37
AEP CASH PURCHASES - NON-ASSOC	2,122,436	77,178,056	36.36	1,512,800	69,292,000	45.80	(20.61)
WIND PURCHASES	241,409	13,616,244	56.40	302,100	16,621,000	55.02	
SPECIAL SERVICE CUSTOMERS	10,103	747,974	74.03	0	0	N/A	N/A
SUBTOTAL	11,196,396	275,710,566	24.62	9,507,200	240,065,000	25.25	(2.50)
<u>INTER-CO DELIVERIES</u>							
PRIMARY ENERGY DELIVERED	(3,739,687)	(65,052,051)	(17.40)	(5,727,400)	(93,961,000)	(16.41)	6.03
OVEC	(760,340)	(15,309,027)	(20.13)	(618,900)	(11,361,000)	(18.36)	9.64
AEP CASH PURCHASES - NON-ASSOC	(1,351,649)	(54,744,259)	(40.50)	0	0	N/A	N/A
OWN GENERATION	(610,414)	(14,345,371)	(23.50)	(6,072,100)	(171,778,000)	(28.29)	(16.93)
SPECIAL SERVICE CUSTOMERS	(20,055)	(1,404,867)	(70.05)	0	0	N/A	N/A
SUBTOTAL	(6,482,145)	(150,855,575)	(23.27)	(12,418,400)	(277,100,000)	(22.31)	4.30
NON-MONETARY INTER-CO REC/DEL	17,381		N/A	0	0	N/A	N/A
NUCLEAR OUTAGE ADJUSTMENT	0	(71,284,454)	N/A	0	0	N/A	N/A
JAN 09 ADJUSTMENT MADE IN MARCH	1,207	(127,034)	105.25	0	0	N/A	N/A
NET ENERGY REQUIREMENT (NER)	23,490,969	358,569,774	15.26	26,122,800	409,634,000	15.68	(2.68)
NER ADJUSTED FOR THREE RIVERS HYDRO AND TRANSMISSION (1.82%)			15.54			15.97	
NER WITH 6% LOSS FACTOR			16.47			16.92	

N/A - NOT APPLICABLE