Exhibit No.:	
Issues:	Fuel Adjustment Clause
Witness:	Lynn M. Barnes
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Direct Testimony
Case No.:	ER-2011-0028
Date Testimony Prepared:	September 3, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2011-0028

DIRECT TESTIMONY

OF

LYNN M. BARNES

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

****DENOTES HIGHLY CONFIDENTIAL INFORMATION****

St. Louis, Missouri
September, 2010

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DIRECT TESTIMONY

OF

LYNN M. BARNES

CASE NO. ER-2011-0028

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lynn M. Barnes. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Please describe your educational background and qualifications.

A. I have a Bachelor of Science degree in Accounting from Millikin University, Decatur, Illinois. I am also a licensed Certified Public Accountant in the states of Missouri and Illinois.

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

A. I am employed by Union Electric Company d/b/a AmerenUE ("AmerenUE" or the "Company") as Vice President, Business Planning and Controller.

Q. Please describe your employment history.

A. After 11 years in public accounting with Deloitte & Touche as an auditor and 16 months with the Boeing Company (formerly McDonnell Douglas Corporation), as Manager of Financial Reporting, I joined AmerenUE in 1997 as General Supervisor of Financial Communications. I was promoted to Manager of Financial Communications in 1999, and my responsibilities included managing the financial reporting department, the regulatory accounting department, and investor relations during the period of transition from a single utility to a public utility holding company with multiple operating companies. I directed financial management functions including preparation and analysis of monthly/quarterly financial statements and external reports for all Ameren Corporation subsidiaries. In 2002, I transferred to Ameren Services Company's Energy Delivery Department as Controller, and in 2005 I was promoted to Director of Energy Delivery Business Services. In July 2007 I was promoted to Controller for AmerenUE and in October 2007 I was promoted to Vice President, Business Planning and Controller for AmerenUE.

Q. Please describe your duties and responsibilities as Vice President, Business Planning and Controller for AmerenUE.

A. In my current position as Vice President, Business Planning and Controller, I supervise the Company's financial affairs, including nearly $2 billion of annual operations and maintenance expenses and capital expenditures. I direct AmerenUE's financial management functions including analysis of monthly/quarterly financial statements, financial forecasting, budget development and management, and management of the customer accounts department. I also coordinate the performance management reporting and the business planning process used throughout the Company. I interact with AmerenUE's Chief Executive Officer and senior leadership concerning strategic initiatives, financial forecasts and reports. I also serve as liaison between AmerenUE's management and the Ameren Corporation controller function.

Q. Have you previously testified in a proceeding before the Missouri Public Service Commission ("MPSC" or "Commission")?

A. Yes. I previously testified before the MPSC in the Company's last electric rate case (Case No. ER-2010-0036) regarding the continuation of the Company's fuel adjustment clause ("FAC"), and in the Company's previous electric rate case (Case No. ER-2008-0318) on miscellaneous cost of service issues.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is to sponsor continuation of the Company's FAC, which was first implemented approximately one and one-half years ago. My testimony includes a schedule (Schedule LMB-E1) reflecting compliance with the minimum filing requirements prescribed by the Commission's FAC rules for continuing the Company's FAC, and also addresses updating the net base fuel costs ("NBFC") which form the base against which changes in the Company's net fuel costs (fuel and purchased power costs net of off-system sales) are tracked in the FAC.

Q. Please summarize your testimony.

A. In summary, the Company's net fuel costs, including each of the major components (fuel and purchased power and off-system sales), continue to be substantial, largely beyond the control of management, and volatile. Moreover, an FAC continues to be necessary in order for AmerenUE to have a sufficient opportunity (likely any opportunity) to earn a fair return on equity. The Commission has determined in two previous rate cases that these conditions warrant the implementation and continuation of the FAC. Continuing the FAC allows the Company to maintain its financial position by sustaining cash flows, thus reducing the need to incur additional debt to fund operations and capital investments. In the current economic climate, keeping credit metrics at investment grade levels is crucial; both the cash flows and the rider mechanism itself are very important attributes to maintaining the Company's current credit ratings.

Continuing the FAC in its current form also promotes regulatory consistency both across the state and with other utilities across the country. This consistency is of critical importance to both the debt and equity investors upon whom the Company must rely for capital. To summarize the foregoing points, current conditions require continuation of the FAC in its current form for AmerenUE to have any chance to earn a fair ROE. Moreover, we have acted prudently in managing our net fuel costs, and have sufficient incentives to do so; therefore the Company's FAC should be continued in its present form.[1]

III. THE CONTINUATION OF THE FUEL ADJUSTMENT CLAUSE

Q. Is the Company requesting to continue its FAC?

A. Yes. The conditions that resulted in the FAC being approved in early 2009 and continued just a few months ago are still present; the FAC is still the most appropriate mechanism to address those issues.

Q. When was the Company's FAC first approved?

A. The FAC was approved in late January 2009 in Case No. ER-2008-0318, and became effective March 1, 2009. The first accumulation period, intended to cover the period February-May, 2009 was only a partial period due to the effective date of the FAC and was completed May 31, 2009. The change in net fuel costs that the Company experienced during this first accumulation period is still being reflected in customer bills (during the period October 2009-September 2010). The Company has subsequently experienced additional changes in net fuel costs in three additional accumulation periods,

[1] The FAC is also fair to customers **--** if net fuel costs do decrease, the FAC is structured so that customers will see a more immediate benefit from those decreases through downward FAC-related rate adjustments on their bills.

two of which are already being reflected in customer rates. The adjustment related to the most recently concluded accumulation period was filed July 23, 2010 and will be reflected in customer bills beginning approximately October 1, 2010.

Q. Have net fuel costs increased or decreased since the FAC was continued in the Company's last rate case?

A. Net fuel costs have increased 16% compared to the base amount (the NBFC referenced above) established in the Company's last rate case (which was based upon a true-up cutoff date of January 31, 2010). This increase is based upon actual and pro forma changes in fuel costs and power prices through February 28, 2011, and will be trued-up as part of the true-up phase of this case. The 16% increase is primarily driven by higher coal and coal transportation costs that will take effect January 1, 2011.

Q. What are the rules for requesting or continuing an FAC?

A. Establishing and continuing an FAC is governed by Section 386.266, RSMo and Commission Rules codified at 4 CSR 240-20.090 and 4 CSR 240-3.161, in particular 3.161(3)(A) through (S), which prescribe the minimum filing requirements for continuation of an FAC. These minimum filing requirements are provided in the attached Schedule LMB-E1.

Q: What are the specific reasons why the Company believes that continuing its FAC is still appropriate?

A. There are several reasons why AmerenUE's FAC is still appropriate. Those reasons are: 1) all of the factors the Commission has generally considered in evaluating FACs favor continuation of the FAC; 2) there is no reasonable opportunity for the Company to earn a fair ROE without the FAC; 3) significant regulatory lag would still be present and would prevent the Company from timely reflecting increasing fuel costs in rates absent an FAC; 4) any modification or elimination of the FAC would reflect an inconsistent regulatory policy which would harm the Company's access to needed capital at the lowest reasonable cost; and 5) AmerenUE's FAC is critical to maintaining the Company's credit quality, both because of the harm to the Company's cash flow metrics the lack of an FAC would cause, and because of the fact that nearly all other utilities with whom the credit ratings agencies compare AmerenUE operate with FACs.

Q. Please elaborate.

A. The Commission initially approved AmerenUE's FAC in part based upon its conclusions about three factors it typically considers when reviewing FAC requests, that is, that the cost or revenue changes must be:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. beyond the control of management, where the utility has little influence over experienced revenue or cost levels; and
3. volatile in amount, causing significant swings in income and cash flows if not tracked.

The Company's fuel and purchased power costs are clearly substantial—they continue to represent the Company's largest single cost item, comprising over $888 million in the test year and 49% of the Company's total operations and maintenance expense reflected in the Company's revenue requirement. The main revenue tracked in the FAC – off-system sales – is also substantial (estimated to be approximately $389 million based upon normalized energy prices and conditions). These costs and revenues also continue to be beyond the control of management. This is because coal and coal transportation costs, natural gas costs, nuclear fuel costs and power prices for off-system sales continue to be dictated by national and international markets. Finally, these costs and revenues continue to be quite volatile, because those same national and international markets continue to be volatile. For example, annual average wholesale power prices decreased 45% from 2008 to 2009 and are expected to recover by approximately 25% by the end of the true-up period in February 2011 (see the direct testimony of AmerenUE witness Jaime Haro and his Schedule JH-E1). In summary, these large fuel and purchased power costs and significant off-system sales revenues cannot be controlled by the Company, and can vary substantially from period to period because of the volatility inherent in the markets in which fuel and purchased power are acquired and in which off-system sales are made.

Moreover, AmerenUE's FAC is absolutely necessary for AmerenUE to have any reasonable opportunity to earn a fair ROE. It is obvious that unless net fuel costs are tracked in the FAC, significant swings in the Company's financial performance and earnings can occur, which can negatively impact cash flows (requiring greater, higher cost borrowings) and affect the Company's ability to earn a fair return on equity. As noted in the direct testimony of AmerenUE witness Gary S. Weiss, even with the FAC in place, we have not been able to earn close to our authorized ROE during the period the FAC has been in effect, and indeed have consistently fallen far short of our authorized ROE for most of the prior three years. The situation would have been much worse over the past year without an FAC. This is because of the impact of significant regulatory lag in the rising net fuel cost environment in which we have been operating for some time now.

AmerenUE's electric retail operating income for the test year ended March 31, 2010, would have been approximately $30 million lower (before true-up) if the FAC had not been implemented in March 2009. Additionally, as shown in the table appearing in Mr. Weiss' direct testimony, AmerenUE's return on equity during that same period was just 8.61%, even with an FAC in place.[2] Without the FAC, the earned ROE would have dropped to 7.58%, which would have been approximately 300 basis points below our then-authorized return on equity of 10.76% and approximately 250 basis points below our most recently authorized return on equity of 10.1%.

Looking forward to 2011, the same problem would exist without the FAC currently in place. Without an FAC, the Company would stand to lose an additional amount of approximately **____________** (which equates to approximately 80 basis points of ROE) due to higher expected net fuel costs between January 1, 2011, and the anticipated effective date of new rates to be set in this case in August 2011. This additional loss is the result of the substantial rise in net fuel costs since the Company's rates were last set just a few months ago (including an anticipated increase in coal, and coal transportation costs in 2011, together with lower off-system sales revenues). I would note that even with continuing AmerenUE's FAC after this case, even with a true-up of certain costs and revenues through February 28, 2011 in this case, and even if AmerenUE witness Hevert's 10.9% recommended return on equity for AmerenUE is

[2] These return on equity figures are adjusted to account for the Company's absorption of the impact of the Taum Sauk Plant being out of service due to the December, 2005 upper reservoir collapse.

adopted, **____** Without an FAC this serious problem would be exacerbated even more.[3]

Q. Does the FAC fully address the lag between the incurrence of fuel related costs and the recovery of those costs?

A. Not entirely. As illustrated by Schedule LMB-E2, it will take at least 16 months between the time when changes in net fuel costs occur and when those changes are fully recovered (in the case of an increase) from customers. This is because unlike in many states, the FAC rules adopted by the Commission require the use of historic, not projected costs, and this is also because of the lengthy 12-month recovery period included in AmerenUE's FAC.

Q. Please elaborate on your points regarding the FAC's impact on credit quality and consistency in regulatory policy.

A. Certainly. AmerenUE's FAC remains critical to maintaining the Company's credit quality and keeping the Company's risk profile (with regard to this issue) essentially on par with the more than 95% of integrated electric utilities across the country that operate with an FAC (including the two other electric utilities in Missouri who are eligible to have FACs). The Commission found in the Company's last rate case, "[i]ncreased financial risk results in an increase in a company's cost of borrowing,

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[3] I would note that the Company's earnings in 2009, **____** demonstrate that some of the arguments made in the past relating to the concern that an FAC might allow the Company to over-earn are proving to be incorrect. I would also note that if net fuel costs come down over time (for example, power prices at some point may increase and thus lower net fuel costs, or fuel prices might decline at some point), the FAC will ensure that customers receive the benefit of those decreases, as opposed to the Company retaining that benefit and earning a higher ROE. The FAC is a two-way street, as demonstrated by the Company's first adjustment, which passed a temporary reduction in net fuel costs on to customers. That situation could arise again, and if it does, customers will get 95% of that reduction.

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ultimately increasing costs that will be passed on to ratepayers."[4] Additionally, both debt and equity investors value consistency in regulation. Inconsistent regulatory policy erodes investor confidence in the utility and casts a shadow on the state regulatory process.

Q. Has the Company updated the NBFC included in the FAC tariff to reflect the current level of NBFC?

A. Yes. When rates are re-set in a rate case, the Commission essentially updates all of the costs and revenues that comprise the revenue requirement to reflect more current conditions. Net fuel costs are one of the elements of the cost of service that must be updated. Consequently, as with every other cost in a rate case, the base level of net fuel costs has been updated to reflect the current levels of fuel and purchased power expense and off-system sales revenues.

In the prior rate case, the Commission set the NBFC at 1.236 cents per kWh for the Summer and at 1.044 cents per kWh for the Winter. The NBFC included in the Company's revenue requirement in this case, allocated between the Summer and the Winter as before, is 1.312 cents per kWh for the Summer and 1.275 cents per kWh for the Winter. The calculation of the NBFC is addressed in detail in the direct testimony of Mr. Weiss.

Q. It appears that NBFC have increased. Please discuss the reasons for that increase.

A. As discussed in the last case, the Company has in place long-term contracts for coal and coal transportation. Delivered coal costs will increase substantially, in accordance with those contracts. Moreover, as discussed in the direct

[4] Report and Order, Case No. ER-2010-0036, p. 78.

testimony of AmerenUE witness Jaime Haro, while the rate of decline in power prices has slowed somewhat, power prices at which off-system sales are made have still continued to fall, which also raises net fuel costs. Consequently, two key cost components tracked in the FAC have increased.[5]

Q. Are you recommending any tariff changes to the FAC?

A. Yes, I am recommending a few minor "housekeeping" changes that do not affect the basic structure or operation of the FAC but which are warranted due to changed conditions. First, there are several factors that have been added to the calculation of NBFC in previous rate cases that are no longer applicable, so we have removed them from the FAC tariff filed in this case. For example, since the Taum Sauk Plant returned to service in April 2010, Factor TS (which was used to give ratepayers the economic benefit of the Taum Sauk Plant as if the plant had actually been in service) has been removed from the FAC calculation, resulting in the Company's net fuel costs being based on the actual operation of the Taum Sauk Plant. Similarly, the replacement power insurance premium adjustment relating to the Taum Sauk Plant has also been eliminated since the plant is now providing service. Other factors that were removed from the tariff include factors that will expire by their terms before the FAC tariff filed in this case would take effect (i.e., the S factor, which will expire by its terms in September 2010). Additionally the sales for resale exclusion from Factor OSSR (off-system sales revenues) has been eliminated so that all megawatt-hour sales to non-retail customers are now included as off-system sales revenues in the FAC. Finally, as approved in the May 2010 rate order, emission allowances purchases and sales are included in the Cost of Fuel

[5] The increase in net fuel costs reflected in our filing in this case is comprised of approximately $58 million in higher delivered fuel (mostly coal) costs, an approximately $9 million reduction in off-system sales

(Factor "CF") in the tariff. The FAC adjustment formula and tariff language has been modified to reflect these changes. A revised FAC tariff, marked to show these housekeeping changes, is attached to this testimony as Schedule LMB-E3.

Q. Does the FAC as currently implemented provide AmerenUE with sufficient financial incentive to be prudent in and take reasonable efforts to minimize its net fuel costs?[6]

A. Yes. The Company has not changed its practices or risk management policies regarding hedging fuel and purchased power costs since the Commission first approved its FAC. Despite the fact that lower power plant maintenance expense levels have been included in rates, plant outages at a rate of two per year are still planned going-forward for the Company's coal-fired base load units. That maintenance, of course, contributes to more efficient plants that are able to generate more off-system sales over time at a lower cost. This directly (and positively) impacts net fuel cost levels for customers. These facts demonstrate that the Company continues to prudently buy fuel and power, and continues to take prudent steps to maximize its off-system sales, as it has always done, and that the Company does have a sufficient incentive to continue to do so.

In addition, unlike most utilities with FACs, the Company will bear five percent of all net fuel cost increases.[7] And as noted earlier, the losses we would incur by not

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revenues, and an approximately $6 million increase in purchased power expense.

[6] The Commission's Order referred to minimizing "fuel and purchased power costs." As discussed earlier, because the Company's FAC tracks fuel and purchased power costs and off-system sales revenues, the relevant measure is "net fuel costs."

[7] In addition to containing a sharing percentage, the Commission's reliance on historic costs to make FAC adjustments also creates substantial cash flow lags, which create additional incentives for the Company to prudently manage its net fuel costs. That lag is considerable. For example, historic net fuel costs incurred between February and June will not even begin to be reflected in rates until October, and will not be fully recovered until the following September, which means that it takes as much as 19 months after some of the costs were incurred to fully recover them.

continuing AmerenUE's FAC in substantially its current form, because of regulatory lag and the inability to time rate cases to fully capture rising net fuel costs, provides a powerful incentive for the Company to act prudently and continue to perform as the Commission expects us to so that the Commission will continue to approve its use. Specifically, the Company continues to prudently negotiate and hedge long-term fuel contracts where appropriate; to prudently sell as much power into the off-system sales markets as it can; and to prudently maintain its power plants to maximize those sales. Also, the existence of the Commission's prudence review process, and the potential for the disallowance of imprudently incurred costs provides another important incentive for the Company to prudently manage its net fuel costs.[8] Finally, we recognize that utilization of a fuel adjustment clause is a privilege, and not a right, which also provides a strong incentive for us to continue to prudently manage our net fuel costs. In sum, there is simply nothing to indicate a lack of prudence on the Company's part, and nothing to indicate that the Company lacks sufficient financial incentives to continue to prudently manage its net fuel costs.

IV. SUMMARY AND CONCLUSIONS

Q. Please summarize your testimony.

A. As the Commission concluded in the Company's last two rate cases, AmerenUE's fuel and purchased power costs and its net fuel costs overall are substantial, largely beyond the control of the Company's management, and volatile in amount.

[8] As the Commission has stated, "'a fuel adjustment clause is a privilege, not a right, which can be taken away if the company does not act prudently.'" Report and Order, Case No. ER-2008-0318, p. 74. (*quoting* Report and Order, Case No. ER-2008-0093, pp. 45-46). The Commission went on to note that "[i]f AmerenUE does not efficiently control its net fuel costs, the Commission could reconsider the fuel adjustment clause." *Id.*

Furthermore, the Commission found that the FAC was necessary to provide sufficient opportunity for the Company to earn a fair return on equity and to compete for capital with other utilities with fuel adjustment mechanisms. All of these considerations still apply and support continuation of the FAC. With the FAC in place, the Company is able to strengthen its financial position by improving its cash flows thus reducing the need to incur additional debt to fund operations and capital investments. In the current economic climate, keeping credit metrics at investment grade levels is critical; both the cash flows and the rider mechanism itself are positive steps to maintaining current credit ratings.

The FAC also provides consistent regulatory treatment among the electric utilities across the state, which is consistent with the regulatory treatment provided by other commissions to utilities across the country. This consistency is of critical importance to the debt and equity investors upon whom the Company must rely for capital, and benefits customers when fuel costs decline.

Long term, customers will benefit from lower interest costs in the Company's revenue requirement and the lower rates enabled by AmerenUE's ability to remain a financially stable company; shareholders also benefit from the FAC because it provides a better opportunity to earn a fair return, as contemplated by Senate Bill 179, the statute that enabled the Commission to approve FACs. The FAC is still the most appropriate mechanism to allow for the timely recovery of changes in net fuel costs to meet these goals.

In sum, we need regulatory consistency with regard to recovery of our fuel costs, and must have an FAC to have any realistic chance to earn a fair ROE. We have acted prudently in regard to managing our net fuel costs, and have sufficient incentives to continue to do so. As a consequence, the Company's FAC should be continued in its present form.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2011-0028

AFFIDAVIT OF LYNN M. BARNES

**STATE OF MISSOURI) **
) ss
CITY OF ST. LOUIS)

Lynn M. Barnes, being first duly sworn on her oath, states:

1. My name is Lynn M. Barnes. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a AmerenUE as Vice President, Business Planning and Controller.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 15 pages, Schedules LMB-E1 through LMB-E3, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Lynn M Barnes
Lynn M. Barnes

Subscribed and sworn to before me this 3 day of September, 2010.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

FAC MINIMUM FILING REQUIREMENTS[1]

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.090(2)(D);

LOCAL PUBLIC HEARING NOTICE

AmerenUE has filed tariff sheets with the Missouri Public Service Commission (PSC) that would increase the company's electric service revenues by approximately $263.3 million. Included in this amount is an increase in the level of net fuel costs that are recovered in base rates of approximately $73 million, which will have the effect of making the company's fuel adjustment clause charges lower in the future than they otherwise would have been. The request would raise a typical residential customer's bill by approximately 10.8%, translating to just more than an approximately $9.30 monthly increase, or approximately 31cents per day. The permanent rate increase request, which is subject to regulatory approval, would take effect no later than the mid-summer of 2011. AmerenUE's rate filing also includes a request to continue its fuel adjustment clause in substantially its current form which would continue to allow 95% of increases or decreases in net fuel costs to be passed through to customers as a separate line item on customer's bills.

Public comment hearings have been set before the PSC as follows:

[To be determined by the Commission]

If you are unable to attend a live public hearing and wish to make written comments or secure additional information, you may contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone (573) 751-4857, email opcservice@ded.mo.gov or the Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, telephone 800-392-4211, email pscinfo@psc.mo.gov. The Commission will also conduct an evidentiary hearing at its offices in Jefferson City during the weeks of __________ through __________, beginning at _____ a.m. The hearings and local public hearings will be held in buildings that meet accessibility standards required by the Americans with Disabilities Act.

If a customer needs additional accommodations to participate in these hearings, please call the Public Service Commission's Hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 prior to the hearing.

(B) An example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with 4 CSR 240-20.090(8);

Attached hereto as Attachments A and B are two different examples of customer bills (one in the postcard format used by AmerenUE for residential customers and one in the billing format used by AmerenUE for non-residential customers), as required by 4 CSR 240-20.091(8).

[1] Each item (A) …. (T) corresponds to the subparagraphs in 4 CSR 240-3.161(3).

(C) Proposed RAM rate schedules;

Attached to the testimony to which this Schedule is attached as Schedule LMB-E3 is Rider FAC - Fuel and Purchased Power Adjustment Clause, which is the proposed rate schedule for the fuel adjustment clause proposed by AmerenUE, and which shows minor changes to the existing Rider FAC as outlined in the testimony.

(D) A general description of the design and intended operation of the proposed RAM;

As discussed in the testimony to which this Schedule is attached, AmerenUE is proposing to continue its existing Fuel and Purchased Power Adjustment Clause ("FAC") in substantially its current form. The FAC applies to all rate classes, and would reflect increases or decreases in fuel, transportation and purchased power costs, including transportation, net of off-system sales revenues ("net fuel costs"), according to the formula expressed in the rate schedule referred to in item (C) above. Historic fuel, transportation and purchased power costs, including transportation, net of off-system sales revenues, would be accumulated during three different Accumulation Periods, as designated in the rate schedule, and then 95% of the change in fuel costs would be recovered (if an increase) or credited (if a decrease) using the calculated FPA (as defined in the rate schedule) over three different Recovery Periods (also designated in the rate schedule), each of which cover a period of 12 months. Two of the three changes to the FPA rate would coincide with the existing seasonal changes in AmerenUE's base rates. The tariff includes two seasonal base amounts, known as the "net base fuel costs" (factor NBFC in the tariff), against which changes in net fuel costs are tracked. The FPA would be applied to customer bills on a per kilowatt-hour ("kWh") basis, as adjusted for voltage level (to take into account varying line losses at different service voltage levels).

The FPA formula includes a factor to accommodate adjustments made as a result of the true-up process or any prudence disallowances occurring as a result of prudence reviews; an "N" factor to address reductions of rate class 12(M) billing determinants under certain conditions specified in the tariff; and a factor to account for an agreement from AmerenUE's last rate case (factor "W" in the tariff).

(E) A complete explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

AmerenUE's continued FAC tariff, which is substantially the same as its existing FAC, continues to be reasonably designed to provide AmerenUE with a sufficient opportunity to earn a fair return on equity for several reasons. First, it provides for full and timely recovery of 95% of the changes in AmerenUE's fuel, transportation, and purchased power costs, including transportation, net of off-system sales revenues, by reflecting increases and decreases in such costs in rates. The 5% of changes not passed through the FAC provide the Company with additional incentives to manage fuel and purchased power costs, but still provide recovery of 95% of those costs. Full and timely recovery of 95% of those costs is based upon the assumption that an appropriate level of costs for fuel and purchased power, including transportation, net of off-system sales, will be set in base rates based upon these costs in the test year, as updated and trued-up in the rate case, and it also assumes appropriate base rate recovery of other cost of service items. With the FAC, it is more likely that fuel and purchased power costs, which are often times much more significant, volatile, uncertain and much more difficult to control than other utility costs, will be timely and fairly reflected in the rates charged to customers. Examples of factors that can often make these very large but critical costs highly volatile, uncertain and beyond the utility's control include the fact that fuel and purchased power is purchased on national markets which are subject to increasing volatility due to global demand, increased trading activities, world events, financial crises, weather (e.g. hurricanes), abnormally hot or cold weather, or other factors. Second, the FAC assists in addressing the relentlessly increasing, volatile and uncertain fuel costs incurred by the Company in providing service to its customers. Third, a continuation of the FAC continues to keep AmerenUE on comparable footing with utilities operating in other states, more than 95% of which use similar rate adjustment mechanisms. Moreover, it will keep AmerenUE on equal footing with the overwhelming majority (36 out of 37) of utilities operating in other non-restructured Midwestern states, including the heavily coal-based utilities (26 out of 27) in these other states. Fourth, the FAC continues to be reasonably designed to provide AmerenUE with a sufficient opportunity to earn a fair return on equity because it mitigates the very significant regulatory lag which is prevalent when dealing with such large, uncertain and often volatile costs, by preventing deterioration in the utility's financial position (including relative credit standing, which is a key determinant of borrowing costs), particularly in the face of known fuel cost increases facing AmerenUE, and by ensuring recovery of actual net fuel costs, which may vary substantially from expected levels.

(F) A complete explanation of how the proposed FAC shall be trued-up to reflect over- or under-collections, or the refundable portion of the proposed IEC shall be trued-up, on at least an annual basis;

The FAC will be trued-up on the first filing date for an adjustment to the FPA rate that occurs at least two months after the end of each 12-month recovery period. Any true-up adjustments will include interest, as provided for in the FAC tariff.

True-up amounts will reflect the difference between net fuel costs authorized for recovery under the FAC for the subject recovery period and net fuel costs actually collected. Actual collections can vary from those expected based upon actual net fuel costs because of variations in the actual kWh sales during a given recovery period versus the estimated KWh sales used to set the FAC rate in effect during a given recovery period.

(G) A complete description of how the proposed RAM is compatible with the requirement for prudence reviews;

AmerenUE's FAC is compatible with the requirement for prudence reviews for several reasons. AmerenUE's FAC is based on actual fuel and purchased power costs, including transportation, net of actual off-system sales revenues, which simplifies the prudence review. The fuel and purchased power costs included in the FAC are well defined in Rider FAC (the FAC tariff), including specific references to the FERC accounts in which the costs are recorded. Moreover, 4 CSR 240-3.161(5), requires the filing monthly of all the supporting data for the fuel and purchased power costs, revenues, plant generation and related information, all of which can be used as part of the prudence review process. These reports are currently being filed by AmerenUE on a monthly basis. This includes providing monthly fuel burn and generating statistics for each of the generating plants. In addition, 4 CSR 240-3.190 requires submission to the Commission Staff each month of information on system output, hourly generation, purchases and sales, planned outages, forced outages and capacity purchases. All contracts for fuel, transportation and purchased power will also be available for review in connection with the prudence review process. The prudence review could also be used in conjunction with an audit plan, through which appropriate financial data can be sampled from the fuel and fuel transportation invoices that will be available.

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records;

These costs are generally described as follows:

Coal Commodity Costs. This will include costs associated with purchase of coal, as well as british thermal unit ("btu") content adjustments and sulfur content quality adjustments associated with coal contracts. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the coal inventory account and allocation of dollars to each plant will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Coal Transportation Costs. This will include costs associated with transportation of coal, as well as fuel adjustments (e.g., diesel surcharges) associated with transportation contracts and price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as coal is used. A detailed accounting of all additions and adjustments to the coal inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period. Railcar costs are included in this account, and a separate accounting of all railcar costs flowing through inventory will be maintained as well as the allocation of costs to plant inventory accounts.

Oil Costs. This will include costs associated with oil and any price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the oil inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Natural Gas Costs. This will include costs associated with the gas commodity, storage, reservation, transportation, hedging costs and oil costs associated with gas-fired plants. A detailed accounting of all additions and adjustments to inventory will be included in a reconciliation, including the calculation of fuel expenses recorded during the accounting period. Also included will be details of all direct costs to expense.

Water for Power. This will include costs associated with water used for hydraulic power generation. Details of water purchased for power will be included in a reconciliation.

Nuclear Fuel Costs. This will include costs associated with nuclear fuel. These costs are accumulated in inventory accounts under FERC Account 120, and amortized on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Cost of Purchased Power. This will include the cost at the point of receipt by the Company of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy or on-peak energy, ancillary services, etc. In addition, this category will include costs incurred from regional transmission organizations ("RTOs") for Revenue Sufficiency Guarantee, Losses, deviation charges, revenue neutrality, inadvertent charges, congestion and firm transmission rights but shall exclude MISO administrative costs arising under MISO Schedules 10, 16, 17 and 24, and shall exclude capacity charges under contracts with a term in excess of one (1) year.

The following table summarizes this information by account:

Type of Cost	Inventory Major	Expense Major	Description
Coal Commodity	151	501	Cost of coal delivered at the mine
Applicable Taxes	151	501/547/518	Applicable taxes on fuel and transportation costs
Btu adjustments	151	501	Added/subtracted amounts to coal contracts for btu content of coal
Coal Quality (sulfur) adjustments	151	501	Added/subtracted amounts to coal contracts for sulfur content of coal
SO_2 Hedge costs/revenues	151	501	Costs/Revenues associated with price hedges related to coal contract SO_2 adjustments
Railroad, truck and barge transportation	151	501	Costs associated with delivering coal from mine to plant
Switching & Demurrage	151	501	Costs associated with switching and demurrage costs incurred in delivering coal from the mine to the plant

Railcar repair	151	501	All railcar costs will be aggregated in a separate minor account under major Account No. 151. As part of the monthly closing process, these costs will be allocated to transportation inventory at the plants based on tonnage delivered during the period.
Railcar depreciation	151	501	
Railcar leases	151	501	
Railcar inspection	151	501	
Heating Oil Hedge costs/ revenues	151	501	Costs/revenues associated with price hedges related to diesel fuel adjustments in coal transportation contracts
Hedge costs associated with coal	151	501	Costs/revenues associated with price swaps, options, or other derivatives to manage fuel costs
Commissions and fees	151	501	Broker costs and commissions associated with hedging activities of coal commodity and transportation
Oil	151	501/547	Costs associated with oil used at plants for generation
Nuclear Fuel	120	518	Costs associated with nuclear fuel, including provisions for transportation, storage and disposal of nuclear fuel including spent fuel disposal fees, and handling costs for nuclear fuel assemblies.
Water for Power	Expensed	536	Costs associated with water used for hydraulic power generation
Fuel costs	151/direct expense	547	Delivered cost of gas, oil, propane, and other fuels used in other power generation
Ash Disposal Costs	Direct Expense	501	Cost to dispose of ash, net of ash revenues
Other Portfolio optimization activities	151	501/547	Revenues and expenses related to selling excess coal or natural gas and other portfolio optimization activities
Purchased Power Costs		555, 565, 575 and 924	Cost of purchased power, but excluding MISO administrative costs under MISO Schedules 10, 16, 17 and 24, and excluding capacity charges under contracts with a term in excess of one (1) year, incurred to support sales to all Missouri retail customers and off-system sales Also included are replacement power insurance premiums to the extent those premiums are not reflected in base rates. Change in replacement power insurance premiums from the level reflected in base rates shall increase or decrease purchased power costs. See Item (I) below relating to the treatment of replacement power insurance recoveries.
Emission	158	509	Cost of purchasing and using emission

Allowances		411.8 411.9	allowances. Also, the gains and losses incurred selling emission allowances.

(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records;

Description	Major	Comments
Off-System Sales	447	All sales transactions (excluding retail sales) that are associated with (1) AmerenUE Missouri jurisdictional generating units and (2) power purchases made to serve Missouri retail customers, including any associated transmission.
Coal Sales	151	Fuel costs reduced by revenues from coal sales
Coal and Transportation Fuel Hedges	151	Revenues associated with price swaps and other hedges related to coal contracts and Fuel for Transportation adjustments
Coal and Transportation Fuel Hedges	151	Revenues associated with price swaps and other hedges related to coal contracts, and Fuel for Transportation adjustments upon settlement.
Railcar leases	151	Transportation costs reduced by revenue from lease of company owned/leased railcars to other companies
Gas Sales	151/547	Revenues and expenses associated with hedging activities and gas portfolio optimization
Ash Sales	501	Sales of fly ash and other types of ash produced at plants
Replacement Power Insurance Recoveries	555	Expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

(J) A complete explanation of any incentive features designed in the proposed RAM and the expected benefit and cost each feature is intended to produce for the electric utility's shareholders and customers;

AmerenUE's FAC contains the same FAC-specific incentive feature the Commission included in its existing FAC, and that has also been included in the FACs initially approved for Aquila, Inc. in Case No. ER-2007-0004, for The Empire District Electric Company in Case No. ER-2008-0093, and that was contained in the continued FAC for Kansas City Power & Light Company – Greater Missouri Operations (formerly Aquila). The FAC is symmetrical. That is, 95% of increases or decreases are passed through the FAC. Given that it is expected that AmerenUE's fuel costs will continue to increase for the foreseeable future, by only passing through 95% of the changes in fuel costs, it is highly likely that customers will benefit by not bearing 5% of those increases. If fuel costs were to decrease (because of, for example, higher off-system sales revenues), customers would receive 95% of the decrease. If off-system sales were outside the FAC, customers would not benefit from those higher off-system sales. Customers also benefit because of the additional incentive to mitigate fuel cost increases created by the fact that the Company will simply not recover 5% of the increase in fuel costs.

(K) A complete explanation of any rate volatility mitigation features designed in the proposed RAM;

AmerenUE's proposed FAC spreads the recovery of the difference between the base fuel costs set in the rate proceeding and fuel costs during each Accumulation Period over a full 12-month period. This has a mitigating effect on rate increases or decreases that will occur as a result of the three periodic FAC adjustments each year. Moreover, as discussed in Item (L) below, AmerenUE utilizes a hedging strategy designed to mitigate fuel cost volatility. Moreover, the FAC is seasonally adjusted and contains seasonally differentiated net base fuel costs. This results in tracking higher actual fuel costs against higher base fuel costs (in the Summer) and lower actual fuel costs against lower base fuel costs (in the Winter), both of which tends to mitigate volatility.

(L) A complete explanation of any feature designed into the proposed RAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RAM;

In addition to keeping books and records relating to fuel, transportation and purchased power in accordance with Generally Accepted Accounting Principles and the Uniform System of Accounts, AmerenUE employs a number of policies, procedures and practices, including the use of internal audits where appropriate, to ensure the prudency of such costs. Described below are relevant policies, procedures and practices.

<u>Fuel Accounting</u>

In order to ensure proper accounting for coal, gas, and nuclear fuel costs, the following procedures and practices are in place.

Coal. A fuel accounting system called Fuelworx is managed by the coal supply and fuel accounting group. Fuelworx maintains information relating to all contracts, and deliveries scheduled and received against each contract. Fuelworx also records statistical and financial records associated with inventory balances, purchases, and fuel consumption. Fuel accounting enters invoice information into Fuelworx, and matches the invoice amount to contracted amounts for coal, transportation, fuel surcharge, and contracted btu and sulfur adjustments. Any discrepancies are resolved by fuels contract administration group. Approved invoices are passed electronically to the corporate Accounts Payable system and paid according to contract terms. This system also performs the pooling process, which allocates 8400 and 8800 PRB monthly pooled coal deliveries to each plant on a delivered, sulfur adjusted average cost. This system is critical as it provides all the data related to coal costs for the month-end closing process; and it ensures that all coal commodity, transportation, and quality adjustment costs have been accrued in the proper period. It also manages the coal pooling process, and records fuel burn information as well. This system is also used to account for oil and limestone costs. All inventory, receivable, and payable accounts associated with coal are balanced on at least a quarterly basis.

Gas. Gas supply executives prepare a month-end estimated gas cost worksheet for AmerenUE's generating units. Current month estimates, plus a true-up of prior month actuals versus estimates, are recorded in the current month. All inventory, receivable, and payable accounts associated with gas are balanced on at least a quarterly basis.

Nuclear Fuel. Nuclear fuel expenses and month end balances are calculated in the nuclear fuel accounting system called Surf'n, which is maintained by the nuclear fuel procurement group. All accounts charged in the general ledger are balanced with the nuclear fuel system on at least a quarterly basis.

Fuel Procurement

Fossil (e.g., coal and natural gas): To ensure fuel purchases are prudent, the fuel acquisition for AmerenUE's generation is governed by the AmerenEnergy Fuels and Services Company ("AFS") Risk Management Policy. The rules and guidelines within the Policy, which were approved by Ameren's Risk Management Steering Committee, identify the levels of coal and natural gas for generation that must be acquired and hedged for future periods, identify the various types of allowable commodity transactions, and create extensive management reporting to monitor all commodity transactions and price positions. The Policy provides that coal and natural gas be purchased using a risk management strategy that secures the required volume for future periods within maximum and minimum policy limits while reducing exposure to market volatility. The volumetric risk (securing the necessary quantities of fuel needed for electricity production) and price risk (entering into financial and physical transactions to hedge against price spikes and volatility in the market) for generation fuels are controlled through compliance with the Policy procurement limits. These limits create maximum and minimum levels of volumetric and price hedging for up to six years into the future to ensure disciplined acquisition of fuel and to diversify price risk over time. Purchasing fuel under these procurement limits provides several benefits, including avoiding the need to purchase large quantities of fuel during periods of price spikes, and ensuring that sufficient quantities are purchased in advance of actual need to minimize any physical shortage that might occur in the fuel markets. These limits do not necessarily result in the lowest possible price for fuel, but strike a balance between price stability and security of supply. In addition to the Risk Management Policy, there are annual fuel supply planning processes which determine the actual acquisition of fuel for generation needs from various production basins and other parameters of fuel supply including transportation, inventory levels, management of inventory levels through purchases and sales, and logistics with power plants/power traders/generation dispatchers. These processes also encompass the development of competitive or alternative transportation methods between transportation providers to ensure competitive and reliable fuel supply. To ensure competitive fuel supply in the commodity markets, the fuel is procured and hedged through several diverse methods including periodic competitive bids, negotiated purchases, electronic trading, Over-the-Counter ("OTC") transactions, futures market transactions, and spot market transactions. In addition to the Risk Management Policy and fuel planning processes, the Internal Audit Department conducts routine audits of fuel supply on a three year cycle for purposes of reporting to senior executives and the Board of Directors. Fuel for generation is purchased by AFS, which is staffed with full-time fuel professionals to manage all aspects of fuel supply and operations with a mission of delivering reliable and competitive fuel supply for all Ameren affiliated companies, including AmerenUE.

Nuclear: To ensure nuclear fuel purchases are prudent, AmerenUE follows a number of corporate procurement practices (as outlined below), including a specific Nuclear Fuel Risk Management Policy approved by the Ameren Risk Management Steering Committee, and a Nuclear Procedure for Nuclear Fuel Contracts. These practices and policies provide very similar controls to those described above relating to procurement of fossil fuels. The foregoing practices, policies and procedures are designed to: i) ensure a reliable supply of nuclear fuel to the Callaway Plant, ii) effectively manage nuclear fuel costs, iii) reduce AmerenUE's exposure to nuclear fuel price volatility, iv) mitigate risks related to nuclear fuel, and v) provide highly reliable nuclear fuel to the Callaway Plant. Nuclear fuel is procured using several processes. AmerenUE utilizes long-term contracts to ensure nuclear fuel is available for Callaway requirements. In addition, inventories of nuclear fuel are maintained to enhance security of supply. AmerenUE also continually monitors market assessments of nuclear fuel supply and demand, price forecasts, and projections of Callaway fuel requirements. This monitoring is an integral part in the continued review of procurement plans. Price and non-price elements, such as reliability of supply, supplier diversity, quality and quantity must also be balanced. In appropriate instances, nuclear fuel procurements are also made through competitive bidding, with all qualified suppliers solicited (however, depending upon the need, in some instances only 2-3 suppliers may be available). Moreover, while the nuclear fuel supply market is worldwide, other than the uranium supply component itself, there are limited suppliers for the other components of the nuclear fuel cycle. With the excellent operating performance of existing plants, and the announced plans for new units, supplies of nuclear fuel have also tightened.

Nuclear fuel procurement is also under the direction and control of a full-time professional in nuclear fuel procurement to manage all aspects of nuclear fuel supply and operations.

(M) A complete explanation of the specific customer class rate design used to design the proposed RAM base amount in permanent rates and any subsequent rate adjustments during the term of the proposed RAM;

The FAC applies the FPA to all of AmerenUE's Missouri electric retail customers (*see* Schedule No. 5 - Schedule of Rates for Electric Service customers). To the extent fuel and purchased power costs are included in base rates the rate design discussed in the direct testimony of AmerenUE witness Wilbon C. Cooper is also applied. With regard to the proposed RAM amount in base rates, a level of 1.312 cents per kilowatt-hour at the generation level is included in Rider FAC for the Summer and 1.275 cents per kilowatt-hour for the Winter, as filed. Adjustments to the rates for each class will be performed in accordance with the formula reflected in Rider FAC and will be reflective of changes in the factors included in the formula versus the values used to determine the RAM amount in base rates. The adjustments reflect a calculation of the FPA based on test year costs and sales consistent with the factors included in the FPA formula in Rider FAC. Actual customer FPA adjustments will be applied to all retail billings for electric service on a per kilowatt-hour basis, as adjusted for losses based on the customers' service voltage (secondary, primary, large transmission service).

(N) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed RAM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility;

Continuing the RAM will not change AmerenUE's business risk. The continuation of a fuel adjustment mechanism (the proposed RAM) would continue to allow AmerenUE to pass through to its customers increases and decreases in fuel costs without the need for a costly and time-consuming rate proceeding necessitated by changes in fuel costs. In recent years, the lack of a fuel adjustment mechanism in Missouri has been a major concern to the financial community because fuel costs have been highly volatile. Because fuel adjustment clauses predominantly are part of the regulation of other U.S. utilities, continuing a fuel adjustment mechanism will keep the business risk of AmerenUE more comparable to the risks of other utilities. Without a fuel adjustment mechanism, the business risk of AmerenUE would be higher than that of other utilities, all else being equal. However, since most of the electric utilities used in the sample groups of comparable companies in AmerenUE's cost of equity studies are able to recover their fuel costs through fuel adjustment clauses, the reduced risk of implementing the proposed RAM in Missouri is already reflected in AmerenUE's base cost of equity recommendation (10.9%) in this case.

(O) A description of how responses to subsections (B) through (N) differ from responses to subsections (B) through (N) for the currently approved RAM;

Items (B) and (C) are unchanged. Item (D) has been updated to account for the inclusion of Factors "N" and "W" in the FAC tariff and for the elimination of Factors "TS" and "S" from the FAC tariff. Items (E) through (G) are unchanged. Items H and I contain minor clarifications (i.e, replacement of "spinning reserves" with the phrase "ancillary services"; specific references to congestion and firm transmission rights; adding relevant account numbers for purchased power costs; adding a separate account listing for emission allowances). Items (H) and (I) have also been updated to reflect the handling of replacement power insurance proceeds now that the Taum Sauk Plant is back in-service. Items (J), (K) and (L) are essentially unchanged Item (L) has been updated to describe the "Fuelworx" fuel accounting system used by the coal supply and fuel accounting group. Item (M) is unchanged, except that it contains updated net base fuel cost figures. Item (N) is unchanged, except that it contains an updated cost of equity figure.

(P) The supply side and demand side resources that the electric utility expects to use to meet its loads in the next four (4) true-up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility;

Attachment C to this Schedule lists the supply- and demand-side resources expected to meet the AmerenUE load requirements for the next four years (September 2010 to August 2011, and each one-year period thereafter). The data in the table lists the resource name, ownership, primary fuel type, heat rate at full load, and projected generation for the four true-up years. The projected generation for these four years is appropriate because they were developed from a detailed production cost model run. The production cost model used by AmerenUE is the PROSYM production cost model. This is the same model that is used by AmerenUE in this case to calculate fuel, transportation and purchased power costs and off-system sales. The major inputs to the PROSYM production cost model include: normalized hourly loads, unit availabilities, fuel prices, unit operating characteristics, hourly energy market prices, and system requirements.

(Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG, steam turbines and combustion turbines conducted with the previous twenty-four (24) months;

Attachment D to this Schedule contains the results of the most recent heat rate tests for the Company's coal-fired units according to the heat rate/efficiency testing processes implemented in connection with the initial approval of the fuel adjustment clause in Case No. ER-2008-0318. These include the most recent reports (Performance Reports) of heat rate tests completed on the Company's coal-fired units, data from heat rate testing at the Callaway Plant, and available heat rate test results for the Company's CTG units.[2]

(R) Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service;

[2] The Company can make available all of the reports during the prior 24 months (some of which were already submitted with the FAC Minimum Filing Requirements in Case No. ER-2010-0036) upon the request of the Commission or any party, but given their voluminous nature, has only provided the most recent reports with this filing. To the extent necessary, the Company requests a waiver of the literal requirement to "file" all such reports.

On February 5, 2008, AmerenUE made its most recently required Integrated Resource Plan ("IRP") filing, reflecting that an important objective of AmerenUE's IRP process is to minimize overall delivered energy costs (i.e. least cost planning) and provide reliable service. This filing covers AmerenUE's long-term resource planning process and consisted of multiple volumes. AmerenUE's IRP filing reflected least cost analyses for a number of resource options and portfolios, and also examined the Company's capacity position and needs in detail. This information included AmerenUE's load forecasts as well as its analysis of available supply-side and demand-side resources. The end result is a twenty year resource plan. AmerenUE's filing was made in compliance with 4 CSR 240-22.010, et. seq. This very comprehensive Commission rule is designed to insure utilities provide energy services which "…are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest." 4 CSR 240-22.010(2). On May 5, 2009, AmerenUE provided a required notice to the Commission respecting a change to its preferred resource plan. The Company is also currently in the process of conducting the work necessary to make its next regularly scheduled IRP filing, which is due to be filed on February 5, 2011.

(S) If emissions allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowances purchases and sales;

The AmerenUE 2009 Environmental Compliance Plan ("ECP") issued in July 2009[3] provides the most complete forecast of AmerenUE's future environmental investments along with its strategy and plans relating to its emission allowances. As the ECP indicates, AmerenUE has no plans to trade (purchase, sell or swap) allowances.

While the ECP remains current as of this time, as noted in Ameren's most recent 10-Q filing (August 9, 2010), the United States Environmental Protection Agency ("USEPA") recently announced the issuance of a new Clean Air Transport Rule ("CATR"), which could have a significant impact on environmental investments and the use of emission allowances. The CATR is currently under evaluation, and the Company plans to submit comments as part of the rulemaking process to the USEPA regarding the proposed CATR. As also documented in the ECP, there are numerous regulations being developed by the USEPA which also could have a significant impact on future environmental capital investments which may be required of AmerenUE's generating plants. AmerenUE is also evaluating the impact of other regulations being developed by the USEPA to determine their potential impact on AmerenUE's generating plants. It is possible that these potential regulations could substantially change the investment plans contained in the July 2009 ECP.

[3] The ECP was attached as Schedule MCB-E3 to the Direct Testimony of AmerenUE witness Mark C. Birk in Case No. ER-2010-0036, and is incorporated herein by this reference.

(T) Any additional information that may have been ordered by the Commission to be provided in the previous general rate proceeding.

The Commission has not ordered any additional information to be provided in connection with a continuation of the FAC.

AmerenUE P.O. BOX 66529 ST. LOUIS, MO 63166-6529

PRES RDG	PREV RDG	USE	READING	RATE	AMOUNT
77604	76343	1261	ACTUAL	1M	129.97
Rider FAC Adjustment					1.74
MO Local Sales Tax					1.32
St Charles Muni Chg					9.91
AMOUNT DUE ON			*08/27*		$142.94

FIRST CLASS MAIL
U.S. POSTAGE
PAID 1 OUNCE
AMEREN

Service at:	123 MAIN	
Service from	07/15 to 08/15/10	Days 31
Last Payment	08/16/10	$185.21
Acct. No 99999-99999	Bill Date	08/17/10

RETURN THIS STUB WITH PAYMENT TO:
AmerenUE
P.O. BOX 66529
ST. LOUIS, MO 63166-6529

Acct. No. **99999-99999**

JANE DOE
123 MAIN
SAINT CHARLES, MO 63301

AMT DUE	$142.94
Due By	08/27
Delinquent After	09/08

Attachment A

Ameren UE
Connecting Missouri

Please Return This Portion With Your Payment

AMOUNT DUE	DUE DATE
$4,585.31	August 27, 2010
AMOUNT PAYABLE AFTER DUE DATE	ACCOUNT NUMBER
$4,654.09	99999-99999

Amount Enclosed $ ________________

CUSTOMER
123 MAIN
AUXVASSE, MO 65231

AmerenUE
P. O. Box 66301
St. Louis, MO 63166-6301

30600000 0099999999909 000004585310 000004585310

Keep This Portion For Your Records

ACCOUNT NUMBER	99999-99999
NAME	CUSTOMER
SERVICE AT	123 MAIN AUXVASSE, MO 65231

BILL DATE	August 17, 2010

TOTAL AMOUNT DUE BY	August 27, 2010	$4,585.31
AMOUNT PAYABLE AFTER	September 8, 2010	$4,654.09

Payment received on Jul 29, 2010 $4,101.29

TYPE OF READING	METER NUMBER	SERVICE FROM TO	NO. DAYS	METER READING PREVIOUS	METER READING PRESENT	READING DIFFERENCE	METER MULTIPLIER	THERM FACTOR	USAGE	RD
Total kWh	99999999	07/15-08/15	31	5766.0000	6214.0000	448.0000	120.0000		53760.0000	A
Peak kW	99999999	07/15-08/15	31	0.0000	0.8200	0.8200	120.0000		98.4000	A

SUMMARY

	Service To			Service To	
Total kWh	08/15/2010	53760.0000	Peak kW	08/15/2010	98.4000
Billing Demand	08/15/2010	100.0000	Total Billing Demand	08/15/2010	100.0000

METERED ELECTRIC SERVICE BILLING

Rate 3M Large General Service			**Service From**	**07/15/2010 to 08/15/2010**	
Demand Charge	100.00 kW	@	$4.15000000	$415.00	
Energy Chg / Hours Used	14,760.00 kWh	@	$0.08890000	$1,312.16	
Energy Chg / Hours Used	19,680.00 kWh	@	$0.06690000	$1,316.59	
Energy Chg / Hours Used	19,320.00 kWh	@	$0.04500000	$869.40	
Customer Charge				$79.89	
Rider FAC Adjustment	53,760.00 kWh	@	$0.00138000	$74.19	
Total Service Amount					$4,067.23
Missouri State SalesTax				$171.84	
Missouri Local Sales Tax				$132.18	
Auxvasse Municipal Charge				$214.06	
Total Tax Related Charges					$518.08

Current Amount Due	$4,585.31
Prior Amount Due	$0.00
Total Amount Due	$4,585.31

A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the delinquent date.

Ameren UE
Connecting Missouri
P. O. Box 66301
St. Louis, MO 63166
1-877-4AMEREN
www.ameren.com

Attachment B

UNIT	Ownership	Primary Fuel Type	Average Heat Rate	9/10-8/11 (MWh)	9/11-8/12 (MWh)	9/12-8/13 (MWh)	9/13-8/14 (MWh)	9/14-8/15 (MWh)
CALLAWAY	AmerenUE	Nuclear	9,941	10,379,700	9,443,300	9,528,200	10,390,900	9,418,500
KEOKUK	AmerenUE	Run of River Hydro	N/A	907,000	916,100	921,400	927,800	942,500
LABADIE 1	AmerenUE	PRB Coal	10,000	4,586,300	4,666,100	4,708,100	4,723,700	3,683,100
LABADIE 2	AmerenUE	PRB Coal	10,196	4,342,300	4,424,700	4,463,000	3,830,700	4,743,900
LABADIE 3	AmerenUE	PRB Coal	10,004	4,574,900	4,653,100	3,932,200	4,715,800	4,694,500
LABADIE 4	AmerenUE	PRB Coal	10,003	4,587,600	3,936,400	4,701,400	4,721,500	4,727,400
MERAMEC 1	AmerenUE	PRB Coal	11,548	681,300	839,300	872,500	770,200	900,700
MERAMEC 2	AmerenUE	PRB Coal	11,301	727,700	793,300	759,700	865,000	875,900
MERAMEC 3	AmerenUE	PRB Coal	11,589	1,780,000	1,722,800	1,911,900	1,910,900	1,744,900
MERAMEC 4	AmerenUE	PRB Coal	10,211	2,140,400	2,494,800	2,556,900	2,342,100	2,587,700
OSAGE	AmerenUE	Pond Hydro	N/A	658,200	661,400	657,500	657,100	657,200
RUSH 1	AmerenUE	PRB Coal	10,149	4,143,000	3,960,500	4,853,100	4,872,900	4,863,400
RUSH 2	AmerenUE	PRB Coal	10,140	4,408,500	4,669,200	4,859,000	4,854,100	4,227,200
SIOUX 1	AmerenUE	PRB/ILL Coal	9,946	2,225,400	3,282,800	3,330,000	3,056,900	3,340,100
SIOUX 2	AmerenUE	PRB/ILL Coal	10,486	2,670,300	3,266,600	2,787,000	3,339,100	3,370,100
TAUM SAUK 1	AmerenUE	Pumped Storage	N/A	368,500	357,850	366,550	365,350	364,100
TAUM SAUK 2	AmerenUE	Pumped Storage	N/A	368,500	357,850	366,550	365,350	364,100
AUDRAIN CT1	AmerenUE	Gas	12,257	700	9,800	15,000	18,900	18,000
AUDRAIN CT2	AmerenUE	Gas	12,255	900	9,300	15,500	16,800	15,900
AUDRAIN CT3	AmerenUE	Gas	12,238	900	10,300	15,100	18,100	15,300
AUDRAIN CT4	AmerenUE	Gas	12,298	900	9,700	15,000	18,500	16,400
AUDRAIN CT5	AmerenUE	Gas	12,294	900	8,300	14,800	17,700	17,800
AUDRAIN CT6	AmerenUE	Gas	12,257	900	10,300	15,500	18,200	18,300
AUDRAIN CT7	AmerenUE	Gas	12,293	900	10,700	14,000	17,800	17,600
AUDRAIN CT8	AmerenUE	Gas	12,288	900	10,000	14,100	18,700	17,800
FAIRGROUNDS CT	AmerenUE	Oil	11,867	0	0	0	0	0
GOOSE CRK CT1	AmerenUE	Gas	12,034	1,200	12,400	16,100	19,800	18,800
GOOSE CRK CT2	AmerenUE	Gas	12,020	1,200	12,600	15,800	19,300	18,500
GOOSE CRK CT3	AmerenUE	Gas	12,016	1,200	12,900	15,900	18,700	19,200
GOOSE CRK CT4	AmerenUE	Gas	12,049	1,200	11,600	15,600	19,800	16,800
GOOSE CRK CT5	AmerenUE	Gas	12,028	1,200	11,900	15,500	19,200	19,200
GOOSE CRK CT6	AmerenUE	Gas	12,024	1,200	12,100	15,600	19,300	19,000
HOWARD BEND CT	AmerenUE	Oil	12,467	0	0	0	0	0
KIRKSVILLE CT	AmerenUE	Gas	25,743	0	0	0	0	0
MERAMEC CT1	AmerenUE	Oil	11,644	0	0	0	0	0
MERAMEC CT2	AmerenUE	Gas	13,895	300	3,700	4,000	7,200	5,200
MEXICO CT	AmerenUE	Oil	11,755	0	0	0	0	0
MOBERLY CT	AmerenUE	Oil	12,089	0	0	0	0	0
MOREAU CT	AmerenUE	Oil	11,867	0	0	0	0	0
PENO CREEK CT1	AmerenUE	Gas	10,632	8,800	22,400	28,100	31,100	32,400
PENO CREEK CT2	AmerenUE	Gas	10,620	8,700	22,400	26,100	32,000	30,500
PENO CREEK CT3	AmerenUE	Gas	10,621	8,300	22,400	26,000	32,900	32,100
PENO CREEK CT4	AmerenUE	Gas	10,628	8,500	22,100	27,400	32,600	31,300
RACCOON CT1	AmerenUE	Gas	11,918	500	9,300	11,200	17,800	16,100
RACCOON CT2	AmerenUE	Gas	11,884	500	9,300	8,900	15,500	16,500
RACCOON CT3	AmerenUE	Gas	11,949	900	11,100	15,600	18,400	17,900
RACCOON CT4	AmerenUE	Gas	11,943	500	9,300	11,400	15,400	15,700
UEFREDW CT1	AmerenUE	Gas	9,994	0	0	116,600	116,600	116,600
UEKINM CT1	AmerenUE	Gas	11,658	1,000	13,200	13,800	24,300	21,200
UEKINM CT2	AmerenUE	Gas	11,656	600	14,600	13,800	24,900	23,200
UEPNK 1	AmerenUE	Gas	9,636	11,300	28,900	33,700	38,000	37,600
UEPNK 2	AmerenUE	Gas	9,627	11,200	29,400	34,300	39,100	38,600
UEPNK 3	AmerenUE	Gas	9,642	11,700	28,500	33,500	37,700	36,600
UEPNK 4	AmerenUE	Gas	9,650	11,500	29,600	34,800	38,000	37,300
UEPNKY 5	AmerenUE	Gas	11,925	500	5,500	5,600	7,900	7,800
UEPNKY 6	AmerenUE	Gas	11,837	300	6,000	5,900	8,100	7,500
UEPNKY 7	AmerenUE	Gas	11,875	500	5,800	6,100	8,400	8,600
UEPNKY 8	AmerenUE	Gas	11,937	500	5,600	6,200	8,800	9,000
VEN CT1	AmerenUE	Oil	14,779	0	0	0	0	0
VEN CT2	AmerenUE	Gas	10,845	4,500	17,700	20,800	25,500	25,400
VEN CT3	AmerenUE	Gas	10,793	5,600	53,100	61,600	82,400	81,800
VEN CT4	AmerenUE	Gas	10,787	5,600	46,200	59,700	80,100	85,400
VEN CT5	AmerenUE	Gas	11,508	1,000	11,200	15,600	22,700	24,900
VIADUCT CT	AmerenUE	Gas	18,709	0	0	0	0	0
Wind	Purchase Power Agreement		N/A	338,100	339,200	338,100	338,100	338,100
Demand Side Management			N/A	574,124	761,393	956,606	1,152,860	1,347,478

AmerenUE Callaway Heat Rate Values – June 2010 (Using ETP-ZZ-01101 Rev 002)

Station Gross Heat Rate (Btu/kWhr)	9545
Station Net Heat Rate (Btu/kWhr)	9989

Attachment D

July 14, 2010

To: David Fox
From: Jeff Shelton
Cc: Bob Meiners, Mark Litzinger, Kevin Stumpe, Brian Griffen, Wes Straatmann, Russ Hawkins, Greg Gurnow, Tony Balestreri, Greg Bolte, Chris Hegger, Scott McCormack, Ken Stuckmeyer, Don Clayton, Joe Sind, Matt Wallace, Scott Hixson, Jim Barnett, Glenn Tiffin, Tim Finnell, Scott Anderson, Cuong Pham

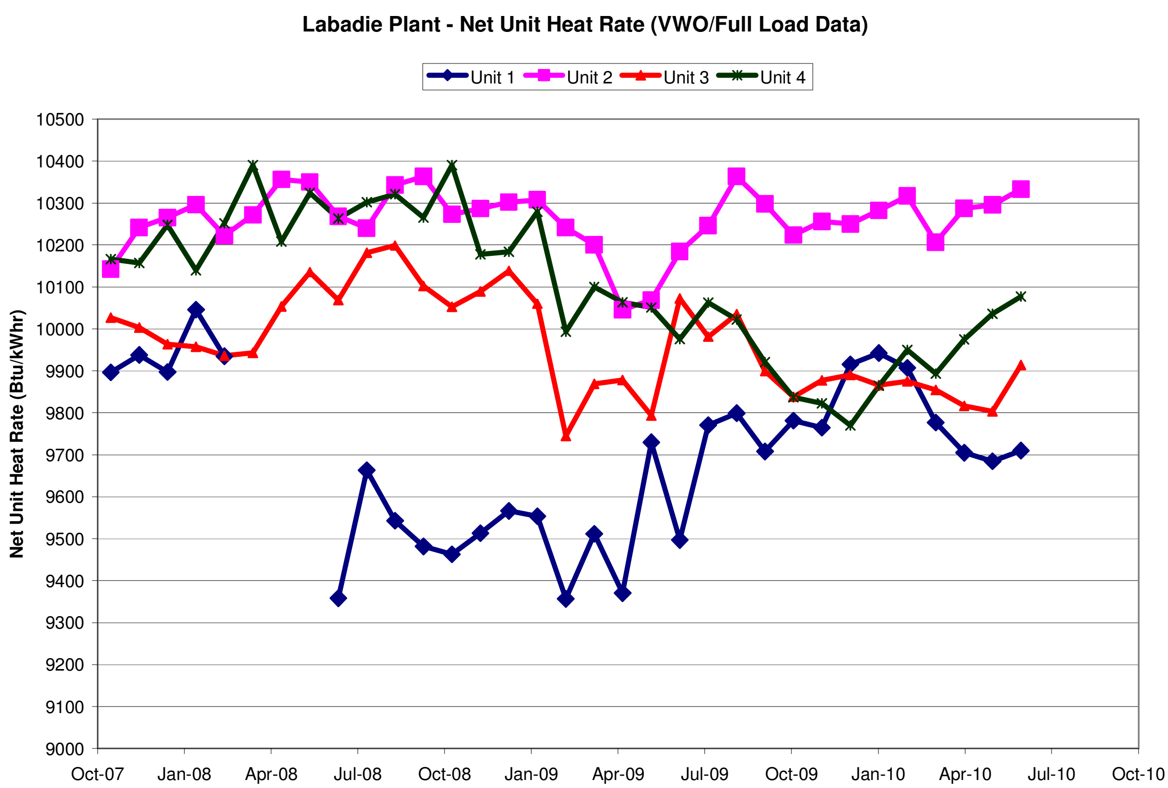
Subject: Labadie June 2010 Performance Report

Executive Summary

The most notable items regarding Labadie unit performance were:

- Condenser pressure is increasing on all units as the river temperature increases. This is leading to increases in heat rate on all of the units as expected in the summer months.
- The 4-1 FWH was OOS for the last part of June due to new tube leaks in the heater.
- The 3-1, 3-5B, 4-5A, and 4-5B FWHs all appear to have tube leaks.

A plot of the monthly average full load heat rate for all four units is given below. Units 1, 3, and 4 operate at a lower heat rate (all three units have had their LP turbines replaced) than Unit 2 as expected. Unit 2 is scheduled to have its LP turbines replaced in 2013.



 Attachment D

Heat Rate KPI

The heat rate KPI for 2010 will be a pay KPI and will be fleet based. Below is a table showing the actual performance of all 12 UE coal units through June. This data represents the net heat rate at full load on each unit (where full load is greater than 425 MW gross for the Sioux units and greater than 90% of the monthly capability for the other units).

The individual unit data is combined into a fleet number by weighting the data by full load MWhrs on each unit. The fleet number is shown in the second table below. The AmerenUE goal is to have a fleet based heat rate improvement of 1.0% over the next five years. The 2010 goal was set by reducing the 2009 fleet averaged heat rate by 0.2%. The threshold goal was set equal to the fleet averaged heat rate achieved in 2009 and the maximum goal was set equal to the 2009 fleet averaged value minus 0.4%.

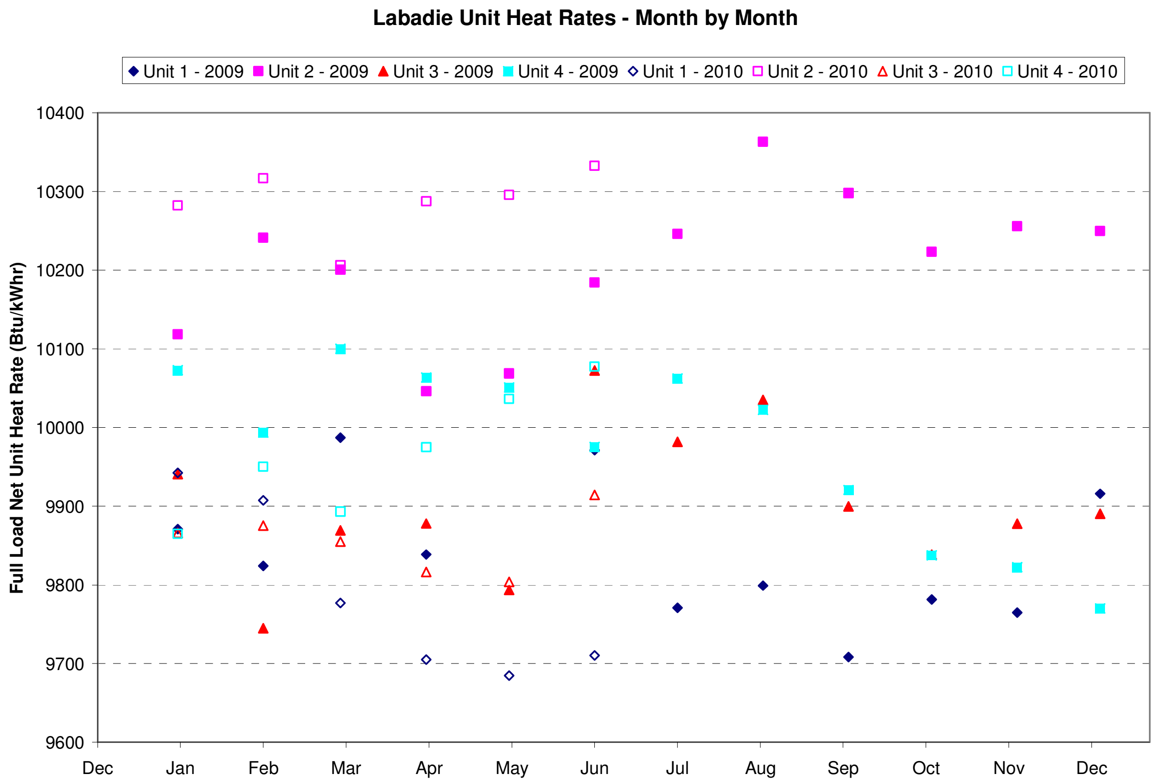
AmerenUE Individual Unit Net Unit Heat Rate at Full Load

Unit	2009 NUHR (Btu/kWhr)	2010 YTD NUHR (Btu/kWhr)	2010 YTD Full Load MWhrs
Labadie 1	9823	9788	2330249
Labadie 2	10214	10283	1825752
Labadie 3	9907	9857	2333757
Labadie 4	9964	9965	2345011
Rush 1	9891	9952	1795859
Rush 2	10482	10002	770160
Sioux 1	9450	9494	1143781
Sioux 2	9925	9854	1145452
Meramec 1	11739	11832	176713
Meramec 2	11821	11680	169824
Meramec 3	11767	11622	710238
Meramec 4	10363	10534	908323

AmerenUE Fleet Averaged Net Unit Heat Rate for Full Load Operation

	2009 NUHR (Btu/kWhr)	2010 YTD NUHR (Btu/kWhr)	2010 Threshold (Btu/kWhr)	2010 Target (Btu/kWhr)	2010 Maximum (Btu/kWhr)
Fleet	10152	10065	10152	10131	10111

The next graph shows the month by month average heat rate values for this year and last year for all four Labadie units. This can be used to compare the performance on the units this year with the same time period last year.



Action Items:

- Performance engineering to resurvey some cycle isolation valves and issue a report summarizing the results.
- Performance Engineering will work with Labadie plant to develop a notification program so that Performance Engineering will get notified of important calibrations.

 Attachment D

Unit 1 Observations

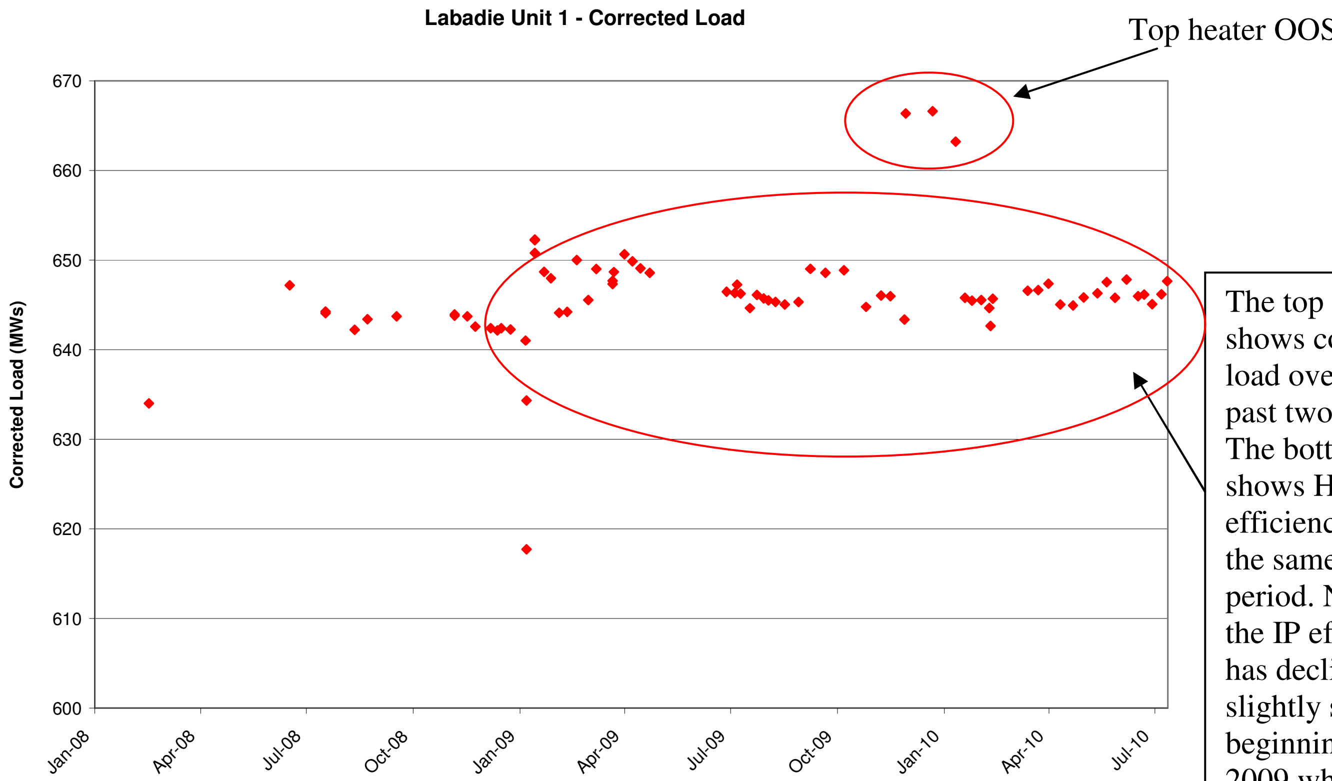
The following observations were made regarding Unit 1 operation and performance:

- It appears that the condenser parasitic heat load calculation (1STM-16195) is no longer working on Unit 1. Following an SBO in May, the parasitic heat value dropped from about 1800F down below 1000F. It does appear that 1STM-16182 went bad during the SBO but would only account for a reduction of 90F. After the July SBO, the parasitic heat load value is now back up above 1000F but still lower than what the individual tags that feed into the total parasitic heat load sum to.
- Performance engineering is monitoring the individual temperatures feeding the condenser parasitic heat load calculation. The following tables details the tags that are indicating potential issues (either high temperatures or potential TC problems):

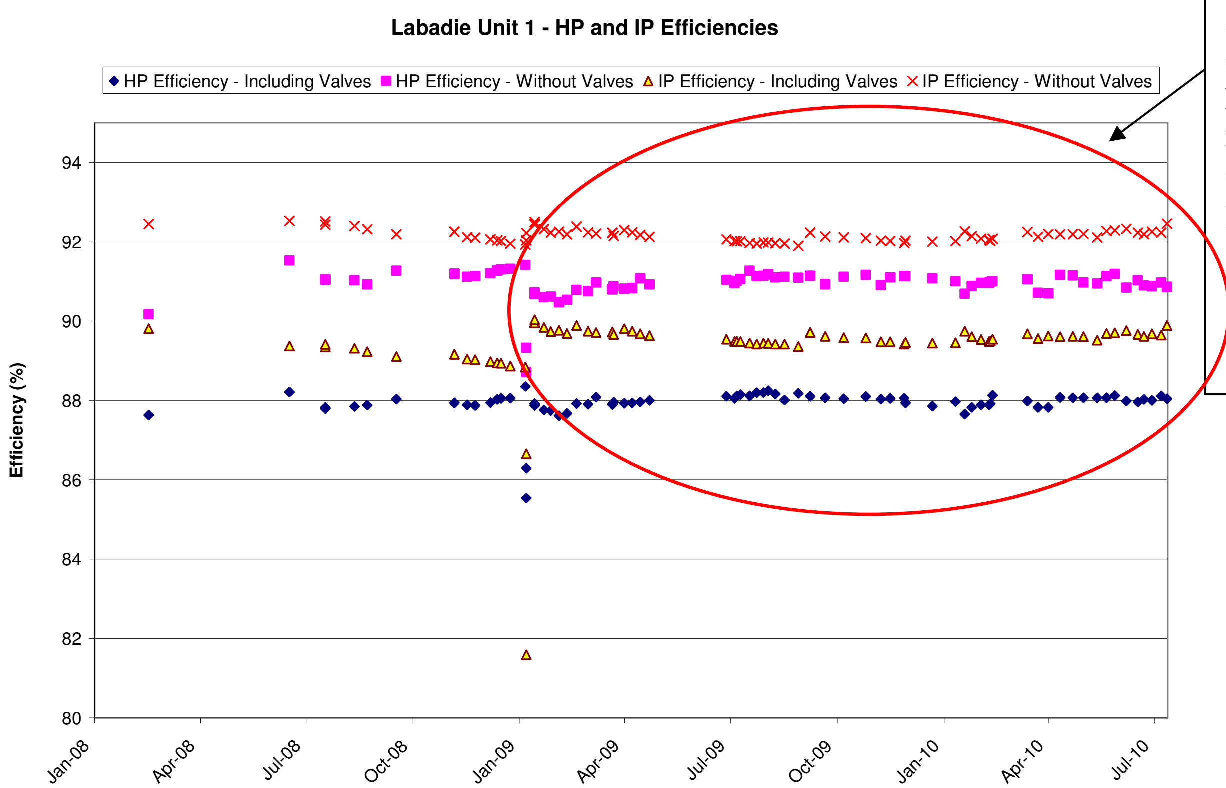
Pi Tag	Issue	JR
1STM-16181 MAIN STM DRAIN MO-5B TEMP	Reading about 250F for the past year. Following the SBO in January, the temperature increased to 370F and has slowly drifted down to about 250F. MO-5A is reading about 100F.	

Summary of Performance Report for:					
Plant	Labadie				
Unit	1				
Period	6/1/10	to	7/1/10		
			Jun-10	May-10	Jun-09
Full Load Performance					
Hours of Data (>90% Monthly Capability)			676	572	72
			Averages	**Averages**	**Averages**
GENERATOR MEGAWATTS	MW		637.5	640.1	631.9
AUX POWER	MW		30.1	30.4	28.3
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		9710.1	9684.8	9496.7
Boiler Efficiency Actual	%		85.5	85.4	84.0
CONTROL VALVE POSITION LVDT	%		83.0	90.5	90.7
FEEDWATER TEMP TO ECON	degF		491.5	491.3	492.7
FEEDWATER TEMP TO HTR 1	degF		438.4	438.7	438.3
HP Turbine Efficiency Actual	%		87.6	87.7	87.4
IP Turbine Efficiency Corrected	%		90.2	90.1	90.8
Condenser Pressure HP	inHga		2.8	2.0	3.3
Condenser Pressure LP	inHga		2.0	1.4	2.2
AIRHTR-A GAS OUTLET TEMP	degF		341.6	332.8	351.9
AIRHTR-B GAS OUTLET TEMP	degF		331.6	324.0	326.2
AMBIENT AIR TEMP	degF		79.7	67.1	81.5
CIRC WTR TEMP TO LP CONDB	degF		76.5	62.8	81.7
CIRC WTR TEMP TO LP CONDB	degF		77.6	65.7	82.6
CIRC WTR TEMP TO LP CONDB	degF		77.5	63.7	82.8
CIRC WTR TEMP TO LP CONDB	degF		76.9	63.0	81.9
Minimum River Temperature	degF		76.5	62.8	81.7
FWH 1 Temperature Rise	degF		53.1	52.6	54.4
Net Load	MW		607.4	609.7	603.5
Average Cond Press	inHga		2.4	1.7	2.8
Average Exit Gas Temperature	degF		336.6	328.4	339.0
Aux Power	%		4.7	4.7	4.5
Gross Unit Heat Rate	BTU/KW-HR		9251.3	9224.8	9070.8
Gross Turbine Heat Rate	BTU/KW-HR		7912.4	7878.5	7620.9
Feedwater Flow	KPPH		4003.8	4059.1	3930.9

Heat rate was up slightly in June and corresponded to an increase in condenser pressure. Most other parameters remained about the same from May.



The top plot shows corrected load over the past two years. The bottom plot shows HP and IP efficiencies over the same time period. Note that the IP efficiency has declined slightly since the beginning of 2009 while the HP efficiency has remained relatively constant. Corrected load has remained fairly constant over the past year.



Unit 2 Observations

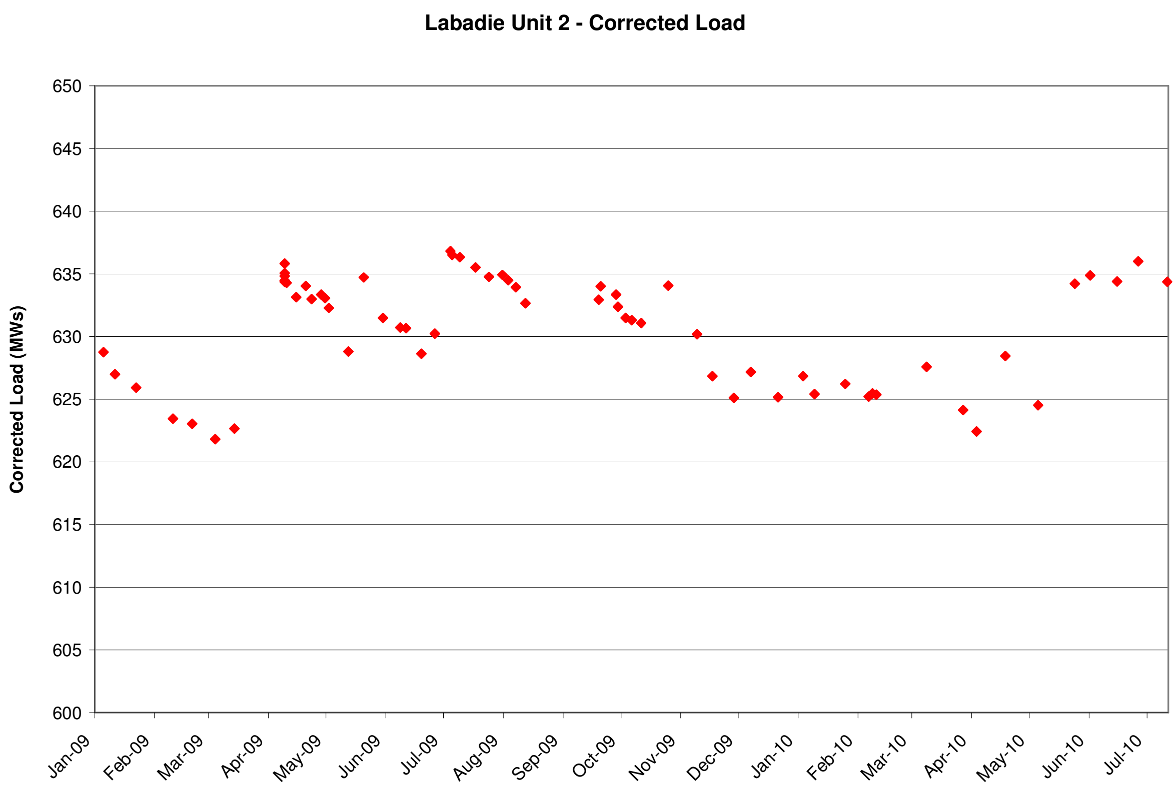
The following observations were made regarding Unit 2 operation and performance:

- Performance engineering is monitoring the individual temperatures feeding the condenser parasitic heat load calculation. The following tables show the tags that are indicating potential issues (either high temperatures or potential TC problems).

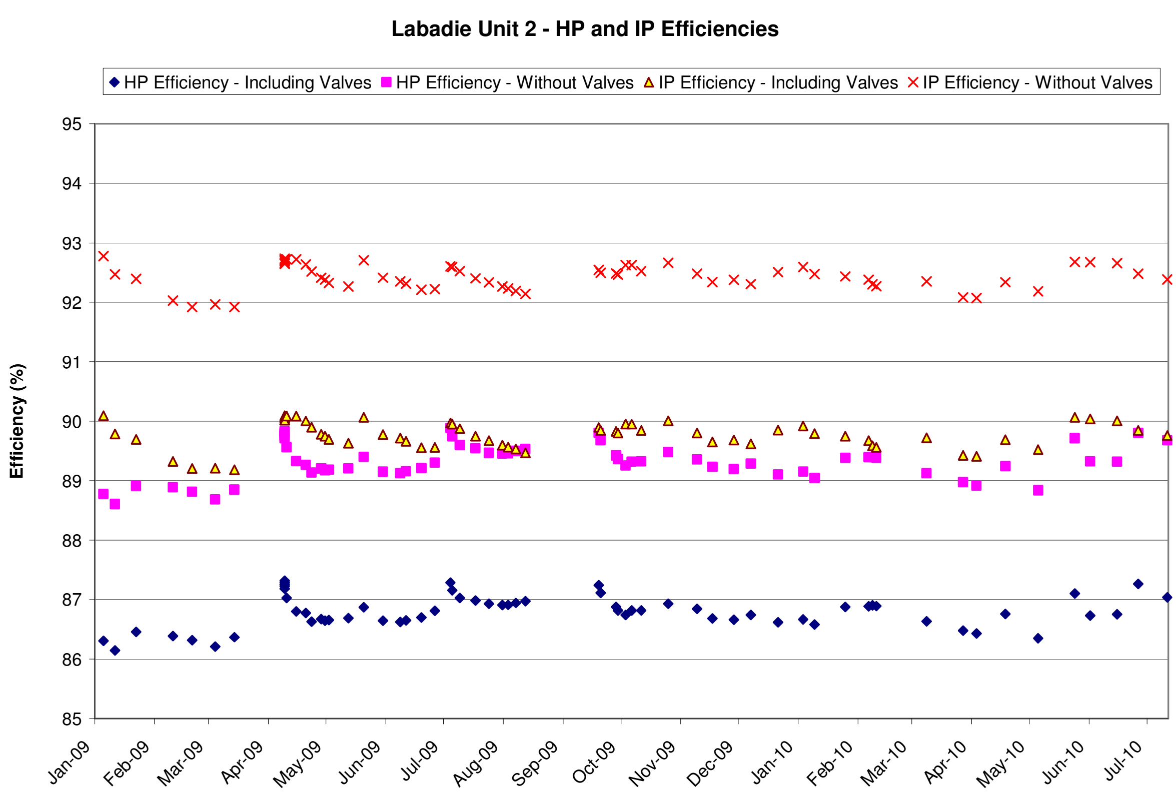
Pi Tag	Issue	JR
2STM-16184 RH STM LEAD DRNS(FV-28 & 29) TMP	This temperature rose from 100F to over 400F in December and has remained elevated. There is an open JR (JR146088) on 2-FV28 written in 2007 about the valve leaking by. There also appears to be a JR (JR134216) to replace 2-FV29 but it was written in 2005. The temperature dropped to 250F after the spring outage but has bounced between 200F and 400F.	JR146088 JR134216
2STM-16103 MAIN STM DRAIN FV-26 TEMP	This temperature has read above 200F since the spring mini-outage.	JR134214
2STM-16177 MAIN STM DRAIN FV-27 TEMP	This temperature has read above 200F since the spring mini-outage.	JR134215
2TURB-16216 GLAND STEAM SPILLOVER TEMP	The temperature indication went from a constant value of about 100F before the spring outage to oscillating between 100F and 250F (and higher) after the outage.	

Summary of Performance Report for:						
Plant	Labadie					
Unit	2					
Period	6/1/10	to	7/1/10			
Full Load Performance			Jun-10		May-10	Jun-09
Hours of Data (>90% Monthly Capability)			497		322	524
			Averages		Averages	Averages
GENERATOR MEGAWATTS	MW		616.5		606.0	618.7
AUX POWER	MW		27.3		28.2	30.0
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		10332.8		10295.6	10184.1
Boiler Efficiency Actual	%		85.1		85.1	85.4
CONTROL VALVE POSITION LVDT	%		81.9		65.2	94.2
FEEDWATER TEMP TO ECON	degF		493.4		491.7	494.1
FEEDWATER TEMP TO HTR 1	degF		441.2		440.1	444.7
HP Turbine Efficiency Actual	%		86.1		85.3	86.4
IP Turbine Efficiency Corrected	%		90.6		90.8	90.1
Condenser Pressure HP	inHga		3.2		2.7	3.1
Condenser Pressure LP	inHga		2.5		2.2	2.6
AIRHTR-A GAS OUTLET TEMP	degF		340.2		337.8	347.7
AIRHTR-B GAS OUTLET TEMP	degF		366.9		356.7	346.0
AMBIENT AIR TEMP	degF		80.9		74.5	79.4
CIRC WTR TEMP TO LP CONDB	degF		76.7		67.5	75.9
CIRC WTR TEMP TO LP CONDB	degF		77.3		67.2	76.2
CIRC WTR TEMP TO LP CONDB	degF		77.4		67.3	76.1
CIRC WTR TEMP TO LP CONDB	degF		76.9		66.6	75.6
Minimum River Temperature	degF		76.7		66.6	75.6
FWH 1 Temperature Rise	degF		52.2		51.6	49.3
Net Load	MW		589.3		577.9	588.7
Average Cond Press	inHga		2.9		2.5	2.9
Average Exit Gas Temperature	degF		353.5		347.3	346.9
Aux Power	%		4.4		4.6	4.8
Gross Unit Heat Rate	BTU/KW-HR		9875.8		9817.1	9690.6
Gross Turbine Heat Rate	BTU/KW-HR		8405.8		8355.5	8276.1
Feedwater Flow	KPPH		4120.6		3953.9	4136.8

Heat rate has increased in June due in part to the increase in condenser backpressure. The average river temperature was up about 10F in June as compared to May and this corresponded to an increase in condenser pressure. The control valves were more open in June which led to an increase in HP efficiency.



Corrected load took a step change up following the spring outage as expected and is similar to the corrected load achieved last spring following the mini-outage.



Turbine efficiencies are also up following the outage as expected and again are similar to the values seen after last year's spring outage.

Unit 3 Observations

The following observations were made regarding Unit 3 operation and performance:

- Corrected load has dropped by about 10 MWs since the beginning of the year on the unit. There was a 5 MW drop over an SBO in January and another 4MW drop in corrected load the last week of May/ first week of June. In looking at the MW trends around the time of the SBO in January, it was noticed that gross load spiked up to almost 700 MWs prior to the unit trip 1/20/2010. In trending three different MW indications, 3LOAD-05000, 3GEN-04995, and 3GEN-04998, there was a definite shift between of the relationships of these tags. Prior to the SBO, 3LOAD-05000 and 3GEN-04998 read very close together and were typically several MW higher than 3GEN-04995. After the SBO, 3LOAD-05000 and 3GEN-04995 read very close together and were typically several MWs lower than 3GEN-04998 (see trend below). The trend appears to have reversed itself back following another SBO in April. It is recommended that the MW indications be checked/calibrated to ensure they are all reading accurately. The MW decrease in late May was coincident with a rather large increase in condenser pressure on the unit. A similar drop in corrected load occurred last year coincident with the summer increase in condenser pressure. The correction factor being used for condenser pressure (supplied by Alstom) was checked with Virtual Plant runs and the results agreed within 0.25%. Performance on the unit will be investigated further after the top heater is placed back in service.
- The 3-1 FWH was removed from service in early February due to suspected tube leaks. It is estimated that operation with the top heater OOS costs about $90/hr in additional fuel costs (higher heat rate). This heater was restored during an SBO in early April. In late April, the heater developed additional leaks. This was determined from observation of step changes up in the normal drainer positions on the top three heaters on the unit. Two additional tubes were plugged in the 3-1 FWH during an SBO in May. In early June, the 3-1 FWH developed another tube leak or leaks as indicated by another step change in the normal drainer position. FU121089-10 was been processed to repair the tube leak(s). The 3-1 was taken back OOS during the relief valve issues on the unit in early July due to high economizer temperatures. There were several control issues with the FWH when the unit came back from the most recent outage and it was left OOS. The tube leaks in the 3-1 FWH still need to be repaired.
- As stated above, a main steam line relief valve failed on the unit in early July and required the unit to be run at a reduced load until an SBO was taken to fix the valve.
- The emergency drainer position on the 3-6B FWH is at 40% open indicating that the 3-5B and 3-6B should be leak checked. The 3-5B normal drainer position went from about 85% at the beginning of February to above 95% at the end of March. The normal drainer is now at 99% open. It is recommended that the 3-5B FWH be leaked checked and repaired at the next opportunity (JR171885).
- Condenser vacuum pump flow remains high on the unit. On 6/3, condenser vacuum pump flow decreased from about 200 SCFM down to about 150 SCFM with a corresponding decrease in LP condenser pressure of about 0.25 in HgA. An elog entry notes "Mtc is painting white goop on the lead seal discs on top of the LP turbines today and the air in leakage rate is dropping a little. There still appears to be a bigger

leak out there some where." Condenser vacuum pump flow remained at about 150 SCFM until the middle of June when the air in leakage started to increase again.

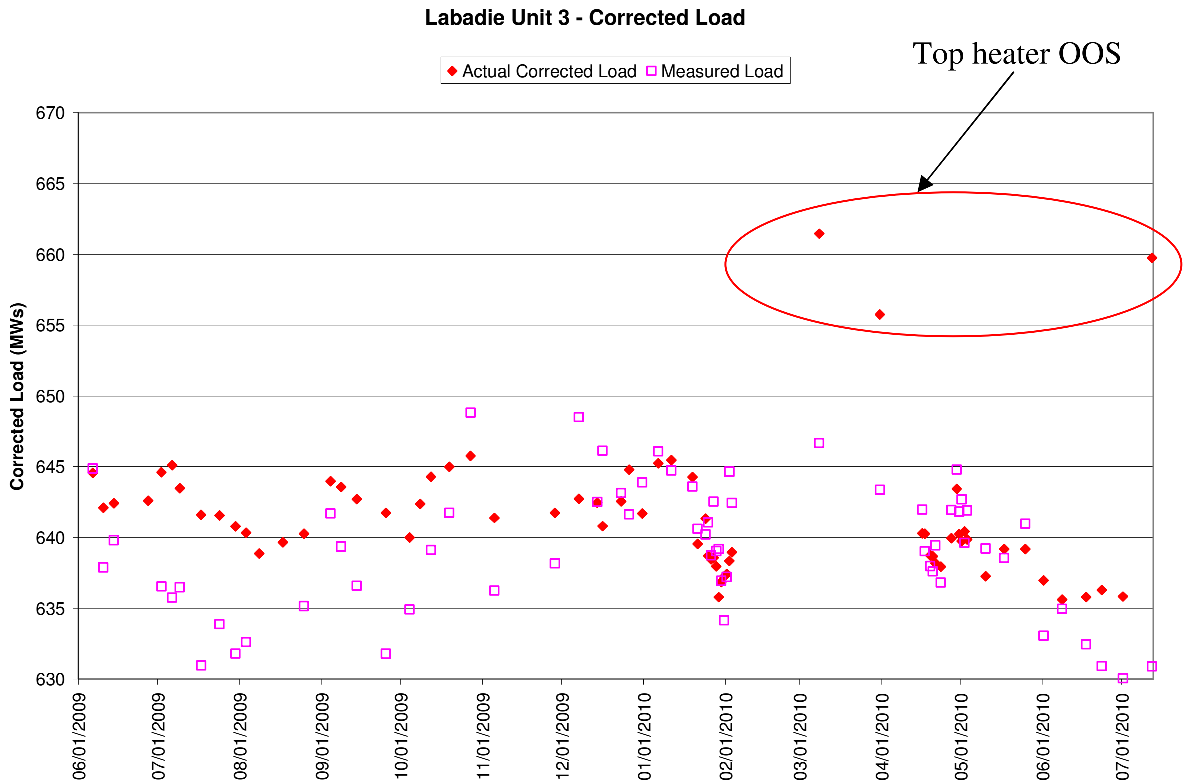
- Performance engineering is monitoring the individual temperatures feeding the condenser parasitic heat load calculation. The following tables show the tags that are indicating potential issues (either high temperatures or potential TC problems).

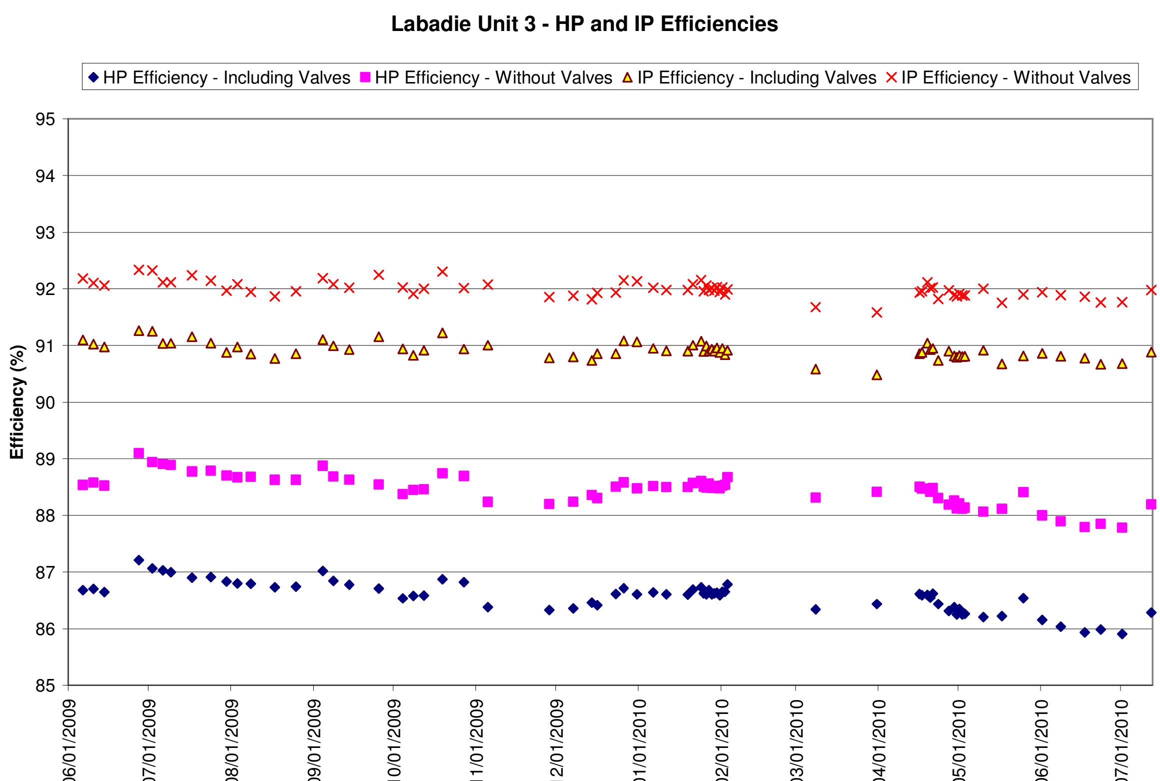
Pi Tag	Issue	JR
3STM-16104 MO-121A & 105A	This temperature indication has been high since the most recent SBO and is reading about 160F.	
3STM-16105 MO-121B & 105B	This temperature indication increased from 115F to above 300F after the early July SBO.	

Summary of Performance Report for:

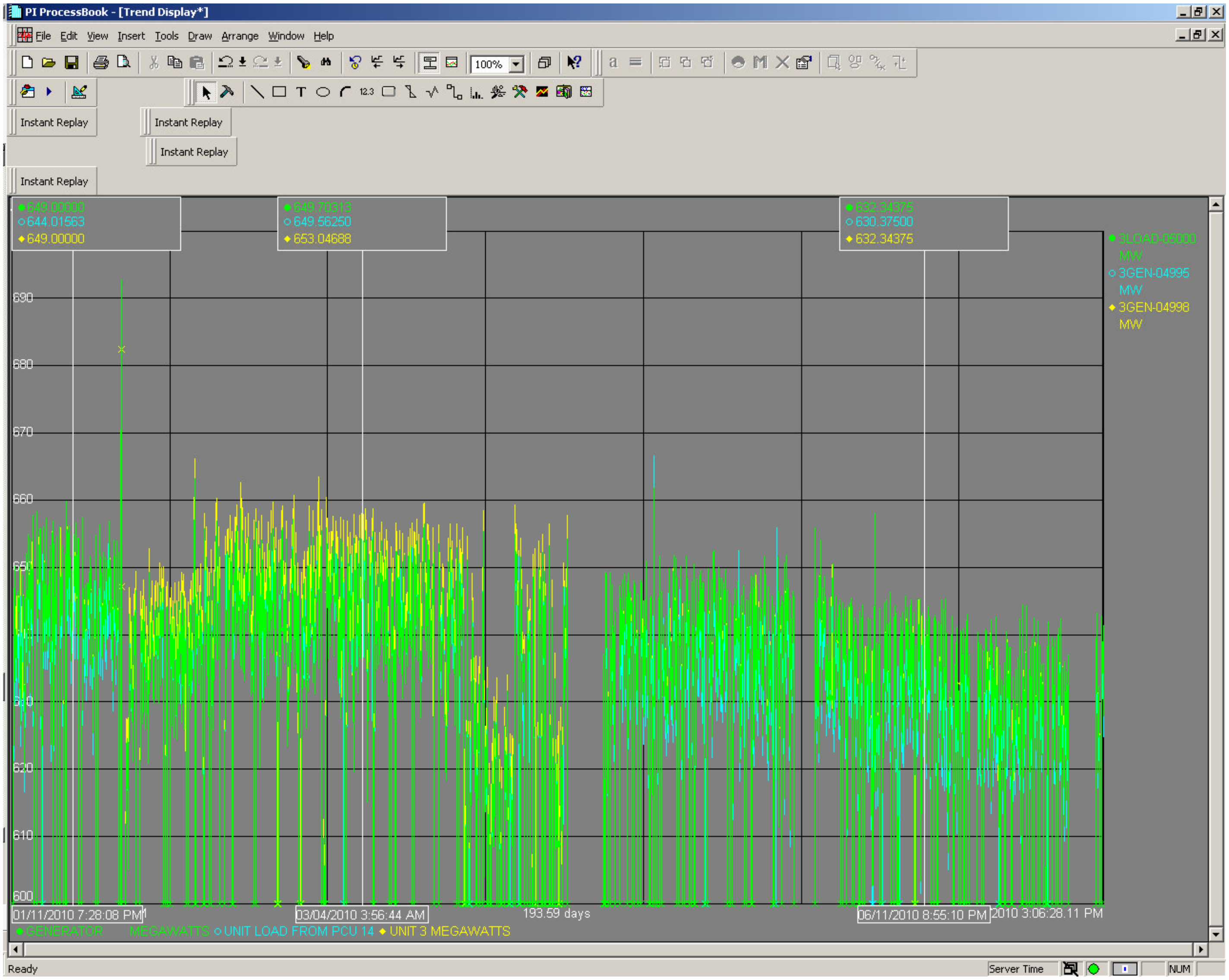
Plant	Labadie					
Unit	3					
Period	6/1/10	to	7/1/10			
Full Load Performance			Jun-10		May-10	Jun-09
Hours of Data			649		625	412
			Averages		Averages	Averages
GENERATOR MEGAWATTS	MW		629.4		636.7	624.6
AUX POWER	MW		29.7		29.1	28.4
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		9914.2		9803.7	10072.4
Boiler Efficiency Actual	%		85.4		85.3	85.3
CONTROL VALVE POSITION LVDT	%		102.0		101.6	99.2
FEEDWATER TEMP TO ECON	degF		487.0		486.8	455.2
FEEDWATER TEMP TO HTR 1	degF		438.4		438.3	414.5
HP Turbine Efficiency Actual	%		85.8		86.1	85.0
IP Turbine Efficiency Corrected	%		92.0		92.0	95.2
Condenser Pressure HP	inHga		3.4		2.7	3.5
Condenser Pressure LP	inHga		2.8		2.6	2.8
AIRHTR-A GAS OUTLET TEMP	degF		354.6		349.2	362.1
AIRHTR-B GAS OUTLET TEMP	degF		339.3		330.8	341.1
AMBIENT AIR TEMP	degF		79.9		68.3	78.0
CIRC WTR TEMP TO LP CONDB	degF		76.8		64.7	75.8
CIRC WTR TEMP TO LP CONDB	degF		77.6		66.5	76.0
CIRC WTR TEMP TO LP CONDB	degF		77.3		64.6	75.8
CIRC WTR TEMP TO LP CONDB	degF		76.9		64.1	75.4
Minimum River Temperature	degF		76.8		64.1	75.4
FWH 1 Temperature Rise	degF		48.6		48.6	40.7
Net Load	MW		599.7		607.6	596.1
Average Cond Press	inHga		3.1		2.6	3.1
Average Exit Gas Temperature	degF		347.0		340.0	351.6
Aux Power	%		4.7		4.6	4.6
Gross Unit Heat Rate	BTU/KW-HR		9445.9		9354.9	9613.7
Gross Turbine Heat Rate	BTU/KW-HR		8069.4		7980.3	8201.5
Feedwater Flow	KPPH		3968.7		3963.0	3735.7

As on the other units, heat rate increased in June and corresponded to an increase in condenser pressure. HP efficiency was down slightly from May while aux. load was up slightly.





The top plot shows measured and corrected load on Unit 3 since June 2009. Note the decreasing trend in corrected load for the beginning of January including the step change down of about 5 MW following the mid-January SBO. Corrected load was very high while the top heater was out of service and dropped back down to more typical values when the heater was returned to service. Since mid-2009, HP efficiency has dropped by about 1% which would cost the unit about 1 MW in load.



The above plot shows the MW trend on Unit 3. Note the spike up above 690 MW in January. Also note the MW indications trends and how the relationship between the three load tags change over the course of the year.

Unit 4 Observations

The following observations were made regarding Unit 4 operation and performance:

- Unit 4 has been operating at a reduced load due to bypassing the LP FWHs on the unit and excessive tube plugging on the 4-5A FWH. An internal bypass was installed on the 4-5A FWH in November 2009 in an attempt to reduce the tube side velocity in the heater and limit the rate of tube failure.
- Unit 4 is currently operating with the highest backpressures and has not undergone a complete mechanical tube cleaning.
- The 4-1 FWH developed a tube leak or leaks on June 8 as indicated by a step change up in the normal drainer position on the 4-1, 4-2, and 4-3 FWHs. The plant processed FU122452-10 to make repairs. The FWH was taken OOS on 6-23 and two new tubes were plugged (one leaking/one insurance plug) were installed. In addition, a previously plugged tube was repaired. The heater is now in service.
- On June 17, the 4-6B FWH outlet temperature (4COND-08177) and the 4-5B FWH outlet temperature, took a step change down from 160F and 240F respectively, down to around 85F. These thermocouples were removed to install a new I-beam for the installation of the new 4-5A tube bundle. In addition, the drain outlet thermocouples are also out of service. The plant is working on reinstalling these thermocouples.
- The 4-5B FWH developed a large tube leak on 6/29 per drainer position indication. The normal level is now being operated in manual and the emergency dump valve is controlling level on the heater. JR173847 was already written to leak check the 4-5B FWH.
- The 4-5A FWH also has tube leaks. The normal drainer position increased 3% over the month of June. JR173173 was already written to leak check the 4-5B FWH.
- Performance engineering is monitoring the individual temperatures feeding the condenser parasitic heat load calculation. The following tables show the tags that are indicating potential issues (either high temperatures or potential TC problems):

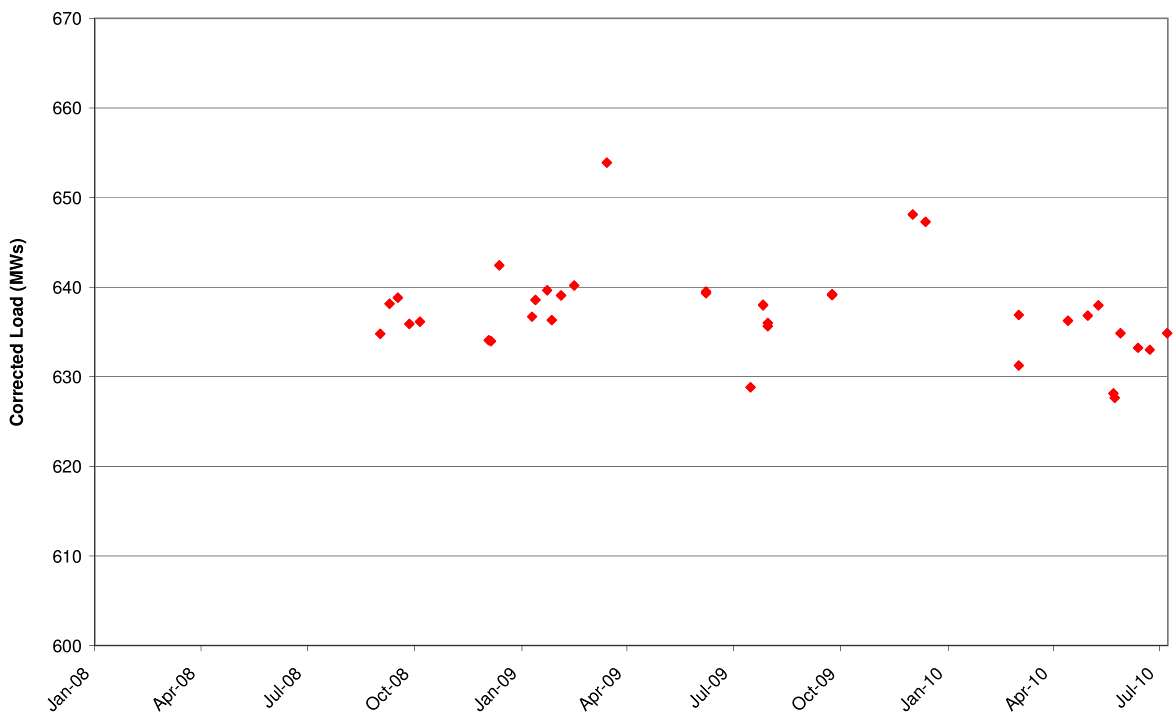
Pi Tag	Issue	JR
4BFW-HPA-16042 BFPT-A FV-215A TEMP	Reading about 250F for at least a year	JR126163
4BFW-HPB-16043 BFPT-B FV-215B TEMP	Reading about 250F for at least a year	JR126164
4STM-16109 MSSV BSD MO-110 & 112 TEMP	Reading over 800F upon startup from April SBO. The temperature has slowly drifted down to about 200F.	JR175186 JR175187

Summary of Performance Report for:

Plant	Labadie				
Unit	4				
Period	6/1/10	to	7/1/10		
Full Load Performance			Jun-10	May-10	Jun-09
Hours of Data (>90% Monthly Capability)			644	637	460
			Averages	Averages	Averages
GENERATOR MEGAWATTS	MW		625.9	627.5	616.5
AUX POWER	MW		29.4	29.0	26.9
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		10077.1	10036.3	9975.3
Boiler Efficiency Actual	%		85.5	85.3	85.3
CONTROL VALVE POSITION LVDT	%		91.3	90.4	84.0
FEEDWATER TEMP TO ECON	degF		471.5	484.3	484.7
FEEDWATER TEMP TO HTR 1	degF		436.3	434.7	434.8
HP Turbine Efficiency Actual	%		85.2	85.5	84.9
IP Turbine Efficiency Corrected	%		92.3	92.5	95.6
Condenser Pressure HP	inHga		3.3	2.7	3.0
Condenser Pressure LP	inHga		3.0	2.9	2.5
AIRHTR-A GAS OUTLET TEMP	degF		349.7	344.1	349.7
AIRHTR-B GAS OUTLET TEMP	degF		345.1	341.3	343.7
AMBIENT AIR TEMP	degF		80.3	69.1	81.0
CIRC WTR TEMP TO LP CONDB	degF		76.8	64.4	76.5
CIRC WTR TEMP TO LP CONDB	degF		77.6	66.2	76.7
CIRC WTR TEMP TO LP CONDB	degF		77.5	64.4	76.6
CIRC WTR TEMP TO LP CONDB	degF		76.7	63.8	76.0
Minimum River Temperature	degF		76.7	63.8	76.0
FWH 1 Temperature Rise	degF		35.3	49.6	49.9
Net Load	MW		596.5	598.5	589.7
Average Cond Press	inHga		3.2	2.8	2.8
Average Exit Gas Temperature	degF		347.4	342.7	346.7
Aux Power	%		4.7	4.6	4.4
Gross Unit Heat Rate	BTU/KW-HR		9603.7	9573.2	9540.8
Gross Turbine Heat Rate	BTU/KW-HR		8209.3	8163.7	8139.4
Feedwater Flow	KPPH		3919.9	3956.1	3707.3

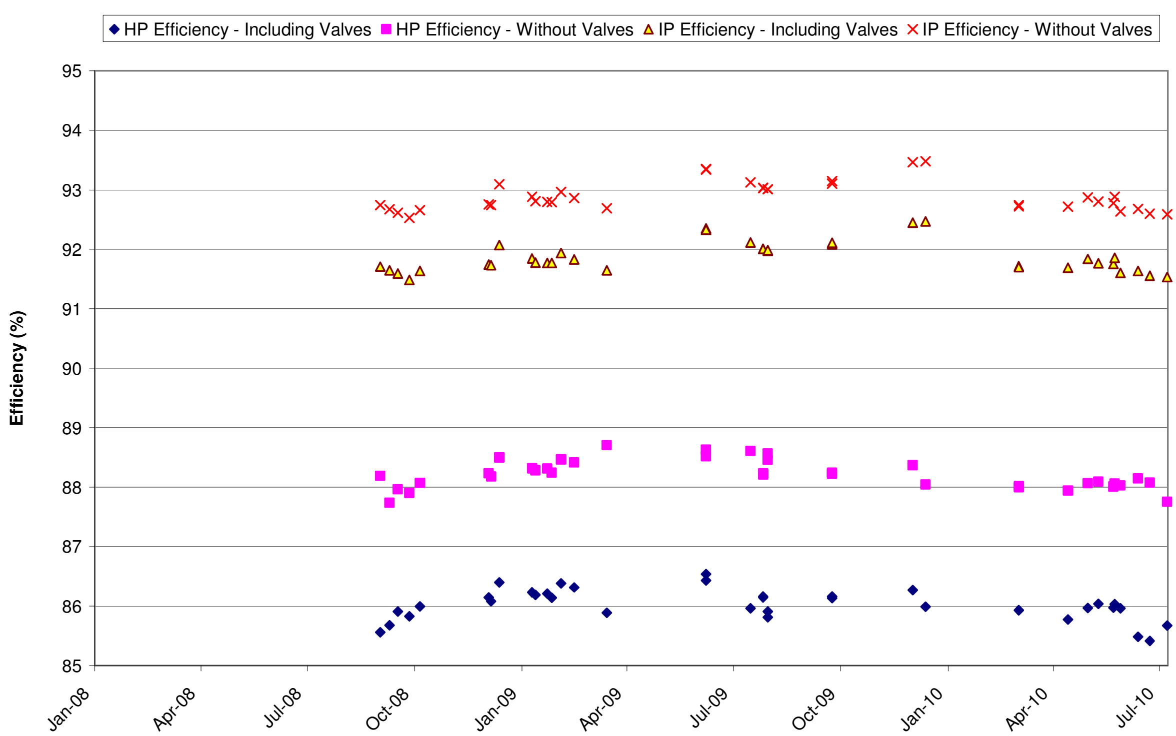
Heat rate was up slightly on the unit and corresponded to an increase in condenser backpressure which is expected at this time of year. The heat rate was also impacted by operation with the top heater OOS for part of the month. Most other parameters remained similar to their May values.

Labadie Unit 4 - Corrected Load



The top plot shows corrected load on the unit back to 2008. Corrected load is down slightly over the time period shown. Note that HP and IP efficiency are about the same now as it was back during 2008.

Labadie Unit 4 - HP and IP Efficiencies



July 27, 2010

To: Tim Lafser

From: Joe Sind

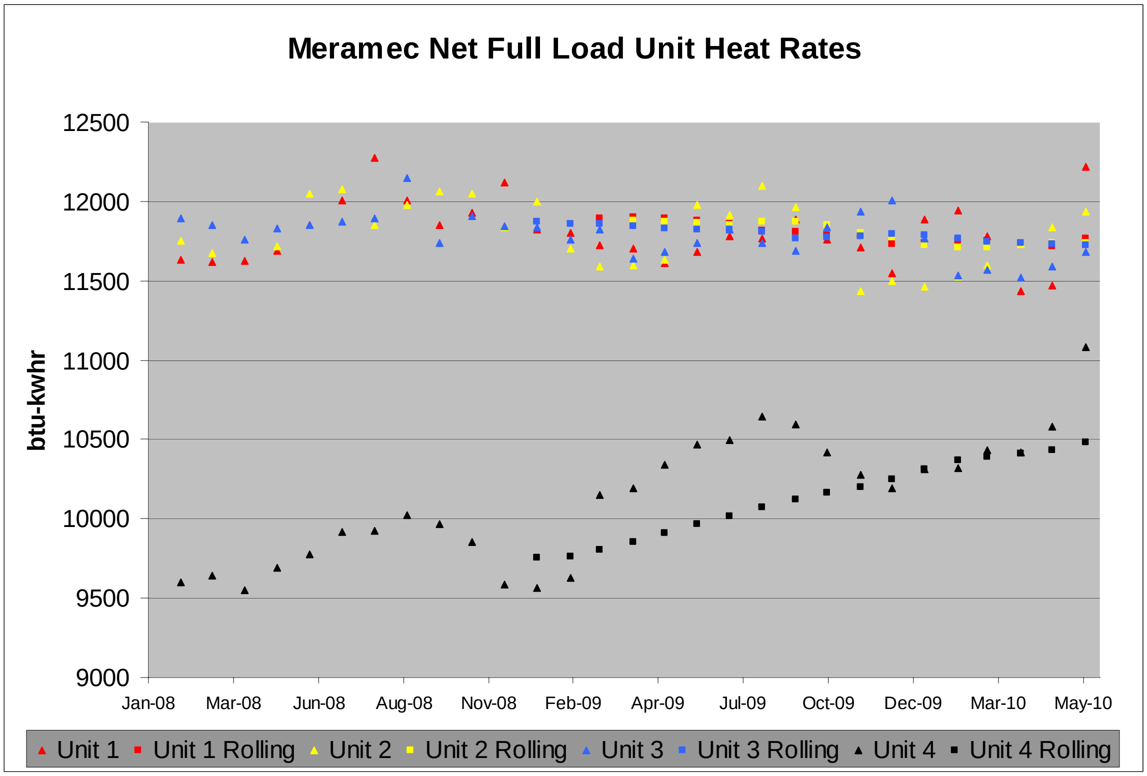
CC: Meiners, Bob R; Beck, John G; Schaeffer, Steven M; Vaughn, James V; Hart, Thomas J; Scott, Jeffrey T; Moade, Michael R; Brown, Christopher M; Wallace, Matthew T; Stuckmeyer, Kenneth B; Clayton, Donald W; Colter, Jeffrey D; McCormack, Scott D; Shelton, Jeffrey D; Hixson, Scott; Barnett, James A; Tiffin, Glenn J; Winkler, Rick J; Finnell, Timothy D; Witges, Kyle T; Roberts, Charles; Taylor, Chris J; Shaw, Steven A; Bosch, James J; Schweiss, Kirk G; Koenig, Arthur D

Re: Meramec June 2010 Performance Report

This report covers data from March through June 2010

<u>Executive Summary</u>

- Unit 1- Has the plant experimented with, and gained sufficient experience with, sliding pressure operation as on Unit 4? If possible this should make a noticeable improvement in turbine heat rate in a derated condition like June and would probably provide benefits on nightly load drops also.
- Unit 4 - The June net unit heat rate is up about 5% from the same period last year and earlier this year. The largest contributor is the increase in turbine heat rate due to the closed IP stop/intercept valves and the partially closed cold reheat check valve. These items occurred mid May and early June. It appears that the turbine heat rate is up about 300 btu/kw-hr due to these affects and at current fuel prices are an increase of about $200/hr or $150,000 per month in production cost.



Following is a summary of known instrument or performance JRs.

Unit	Date Noted	Inst/Ops/Pi/EtaPRO/H	Description	JR	JR Status
1	11/07/2008	Inst	A hot reheat press not valved in or not existant	JR092913	ENRQ
1	07/28/2009	HeatRate	Excessive Leakage from HP glands to No 3FWH extraction	JR094280	ENRQ
1	07/28/2009	HeatRate	Excessive leakage from IP dummy piston to No 5 FWH extraction	JR094283	ENRQ
1	10/08/2009	Inst	B Crossunder temp went to Bad Input on about 9/10/09	JR095495	PLAN
2	07/28/2009	HeatRate	Excessive Leakage from HP glands to No 3FWH extraction	JR094281	ENGR
2	07/28/2009	HeatRate	Excessive leakage from IP dummy piston to No 5 FWH extraction	JR094285	ENGR
2	10/03/2008	Inst/Ops	FWHs 1 and 2 drain temps reading lower than inlet feedwater	JR092972	CLSD
3	03/01/2009	Inst	Please help trace down and calibrate and set up instrumentation for a turbine performance test. (02/26/2009 08:43:30, WETTEROFF,DJ)	JR091446	PLAN
3	10/19/2009	Inst	Install a pressure transmitter and wiring and make modifications to the DCS system to allow for DCS indication of the Unit 3 crossunder pipe pressure.(10/19/2009 10:02:40, WETTEROFF,DJ)	JR095696	PLAN
4	03/27/2009	Inst	CONDENSER H2O OUT EAST TEM reads bad input since 6/27/07	JR080279	INSC
4	03/27/2009	Inst	HTR 2 DRAIN TEMP reads lower than feedwater temp to FWH1, not possible	JR093097	ENGR
4	06/23/2010	Inst	Pi tag 4TRW360K ID Fan discharge temperature, went Bad Input on 4/30/2010.	JR099967	APRV

Summary of Performance Report for:

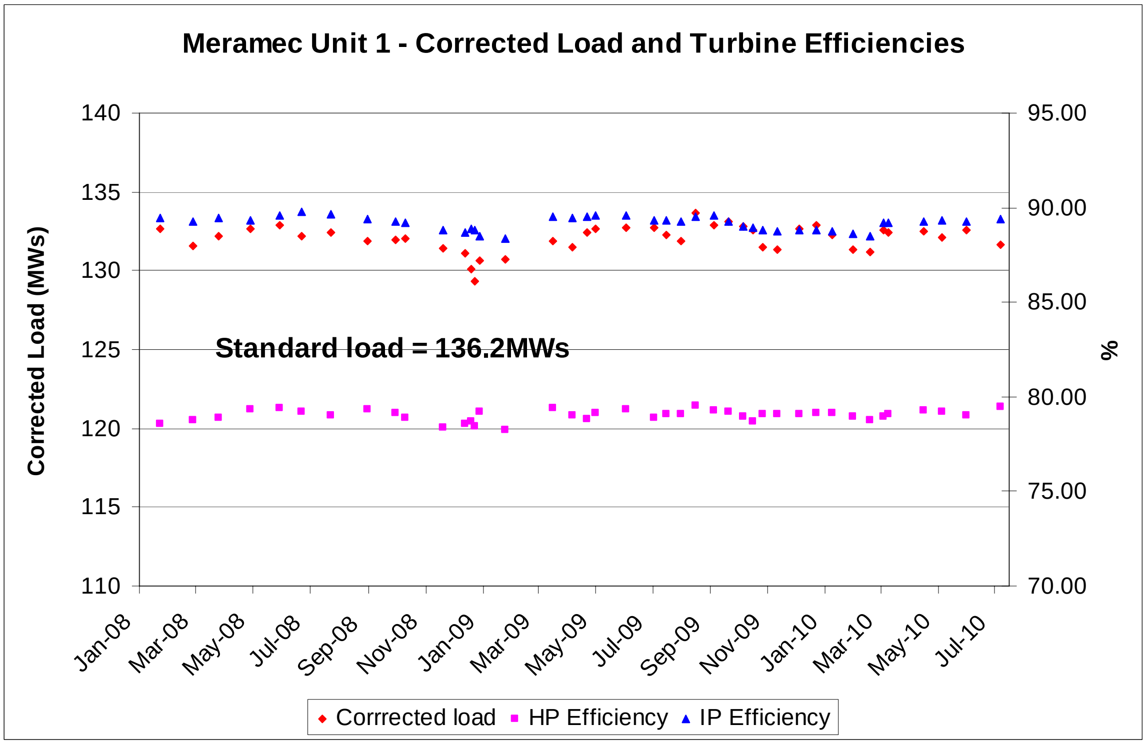
Plant	Meramec						
Unit	1						
Period	6/1/10	to	7/1/10				

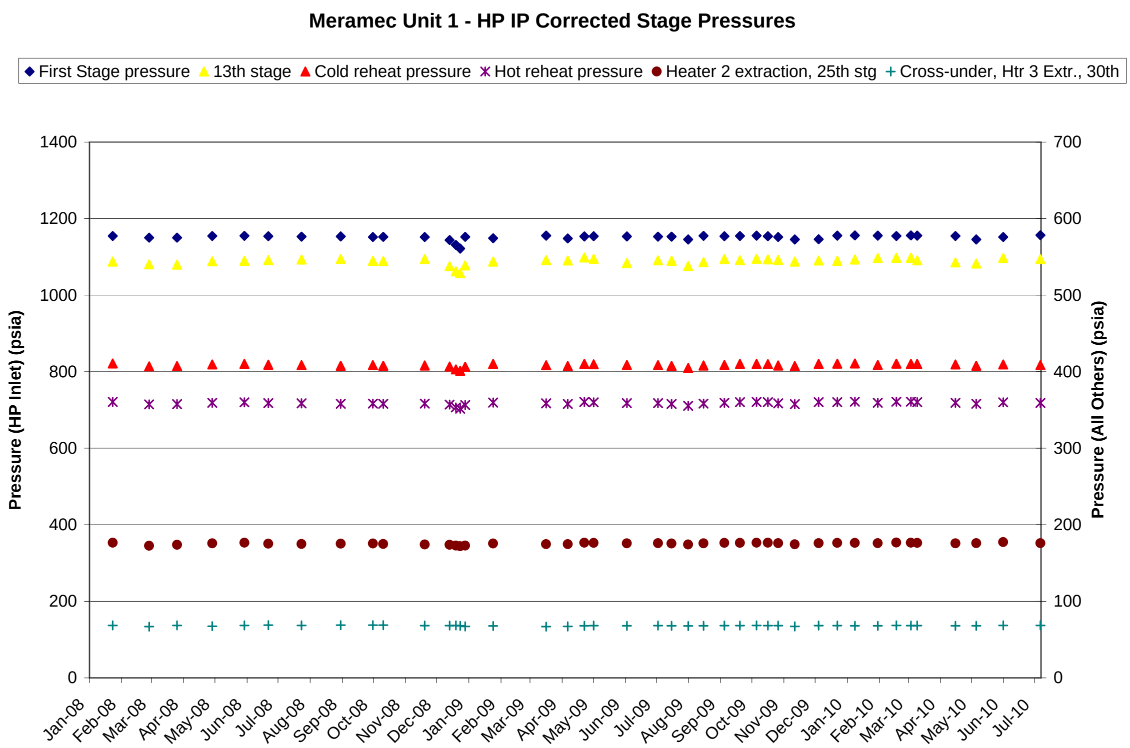
Full Load Performance

		Jun-10	May-10	Apr-10	Mar-10	Jun-09
Hours of Data (>90% Monthly Capability or >97% calc GVP)		695	90	72	88	336
		Averages	**Averages**	**Averages**	**Averages**	**Averages**
Generator Megawatts	MW	85.8	131.0	133.8	134.6	131.0
Aux Power	MW	7.5	9.1	9.1	9.5	9.3
Aux Power	%	8.8	7.0	6.8	7.1	7.1
Net Load	MW	78.3	121.9	124.7	125.1	121.7
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR	12216.9	11467.6	11432.1	11777.7	11680.4
Gross Unit Heat Rate	BTU/KW-HR	11147.4	10670.1	10655.6	10944.5	10850.7
Boiler Efficiency Actual	%	85.7	85.2	85.1	84.8	85.6
Gross Turbine Heat Rate	BTU/KW-HR	9552.8	9095.5	9068.8	9285.4	9291.8
Control Valve Position	%	77.0	99.7	99.8	99.8	99.9
Feedwater Temp To Economizer	DEGF	409.9	449.5	449.9	450.1	449.6
Feedwater Temp To Htr 1	DEGF	342.3	372.5	372.1	372.5	372.2
HP Turbine Efficiency Actual	%	72.2	79.0	79.1	79.0	79.1
IP Turbine Efficiency Corrected	%	89.7	89.3	89.3	89.2	89.4
Condenser Pressure	inHga	2.4	2.6	2.3	2.0	2.9
Circ Water Temp to Condenser	DEGF	79.4	70.9	62.4	41.7	79.7
Air Heater Gas Outlet Temp	DEGF	300.5	317.1	311.6	302.8	314.1
Ambient Air Temp	DEGF	83.2	83.2	75.0	47.2	86.0
Air Temp to Air Heater	DEGF	105.3	98.7	88.9	68.9	
Gas Temp to Air Heater	DEGF	495.7	576.1	572.6	581.9	
Throttle Pressure	PSIG	1247.1	1269.3	1287.8	1285.0	
Throttle Steam Temp	DEGF	935.0	950.0	949.9	949.9	
Superheat Spray Flow	KPPH	4.7	17.4	12.7	12.2	
Reheat Steam Temp	DEGF	928.9	948.7	949.3	944.9	
Reheat Spray Flow	KPPH	2.0	14.1	7.4	14.1	
Excess Oxygen	%	2.2	1.7	1.9	1.8	
Carbon Monoxide	PPM	283.4	212.9	176.0	124.1	
Feedwater Flow	KPPH	662.7	992.3	1023.9	1051.1	
Steam Flow	KPPH	670.3	1039.8	1060.8	1060.2	
Feedwater/Steam Flow		0.989	0.954	0.965	0.991	

The data presented for June is atypical of the other periods due the unit being derated for opacity concerns. Net heat rate is up about 7% compared to the previous month due mostly to an increase in turbine heat rate and auxiliary power (%).

Turbine operation review during this time indicates that throttle pressure was held constant at about 1200 to 1250 psi and all load control was with the governing valves. Individual governing valve positions are not available in Pi and it is assumed the machine operates in a sequential valve mode. Has the plant experimented with, and gained sufficient experience with, sliding pressure operation as on Unit 4? If possible this should make a noticeable improvement in turbine heat rate in a derated condition like June and would probably provide benefits on nightly load drops also. Note the HP turbine efficiency is 7% lower than other data where the GVs are wide open.



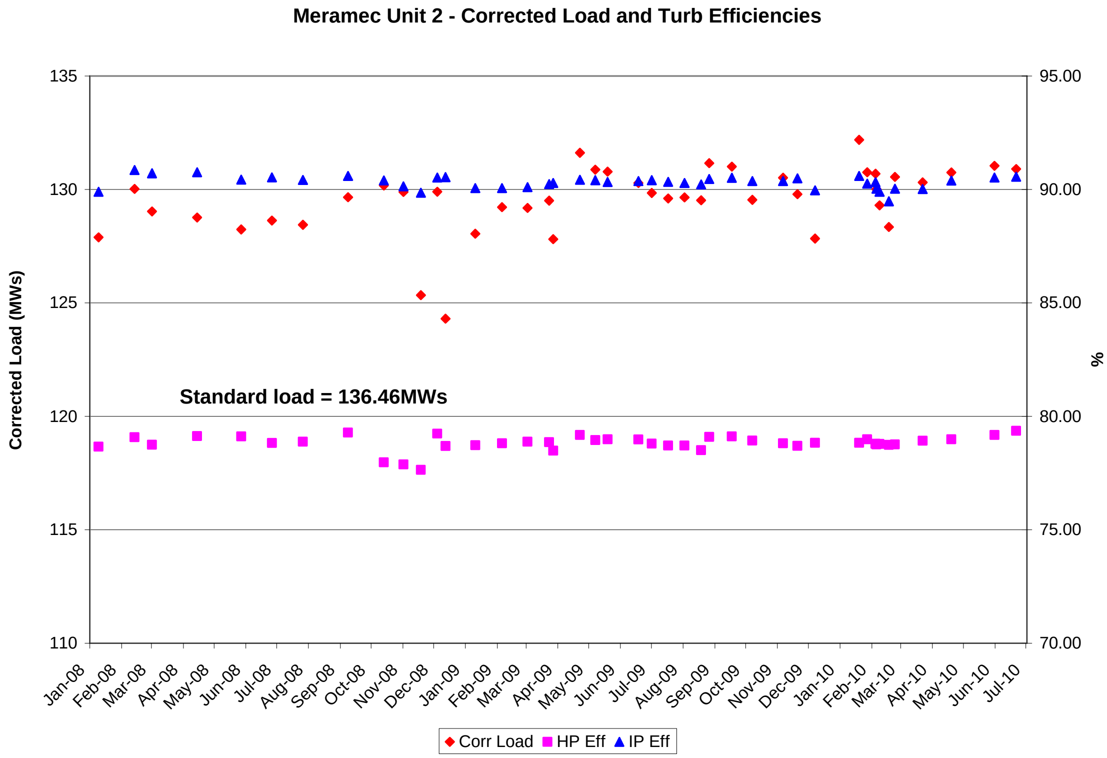


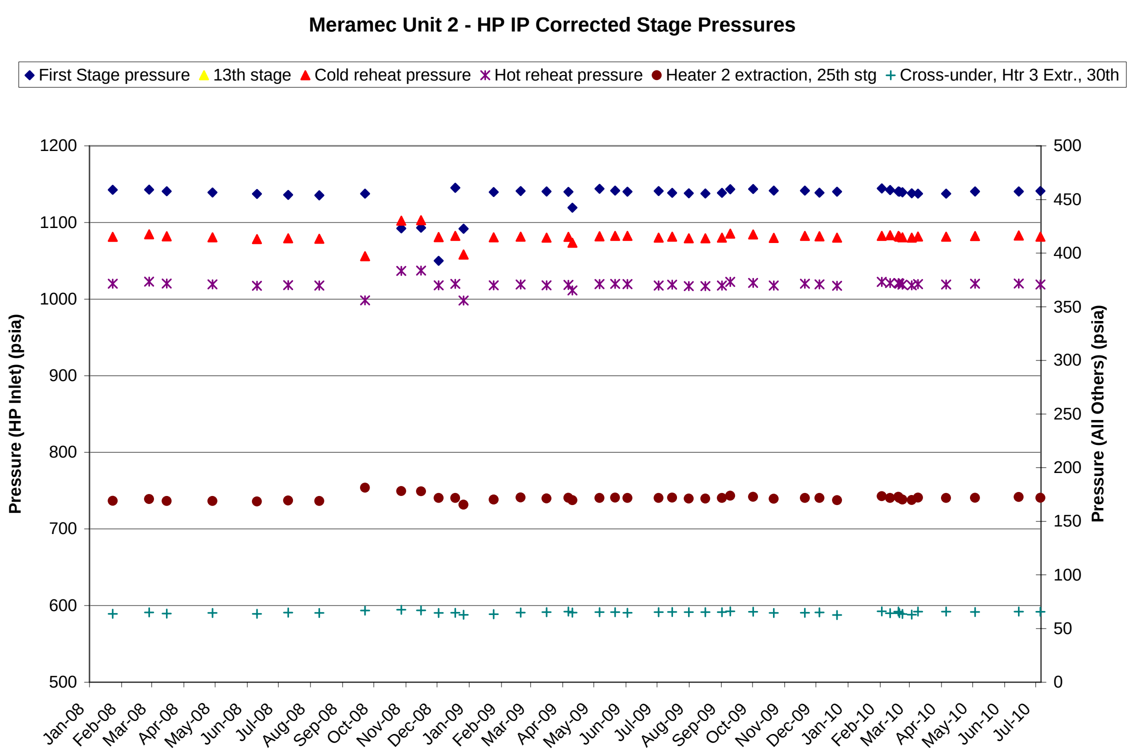
Attachment D

Summary of Performance Report for:

Plant	Meramec						
Unit	2						
Period	6/1/10	to	7/1/10				
			Jun-10	May-10	Apr-10	Mar-10	Jun-09
<u>Full Load Performance</u>							
Hours of Data (>90% Monthly Capability or >97% calc GVP)			246	91	39	103	194
			Averages	**Averages**	**Averages**	**Averages**	**Averages**
Generator Megawatts	MW		133.5	134.5	135.2	137.3	129.6
Aux Power	MW		7.6	7.5	7.4	7.3	7.7
Aux Power	%		5.7	5.6	5.5	5.4	5.9
Net Load	MW		125.9	127.1	127.8	129.9	121.9
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		11934.1	11836.8	11731.3	11595.2	11975
Gross Unit Heat Rate	BTU/KW-HR		11256.3	11178.4	11090.2	10974.8	11263
Boiler Efficiency Actual	%		84.0	83.9	84.0	84.2	84.4
Gross Turbine Heat Rate	BTU/KW-HR		9457.9	9378.0	9313.0	9238.1	9501
Control Valve Position	%		98.3	98.3	98.2	98.1	98.3
Feedwater Temp To Economizer	DEGF		452.5	452.4	452.1	453.1	452
Feedwater Temp To Htr 1	DEGF		372.8	372.7	372.2	372.3	371
HP Turbine Efficiency Actual	%		79.1	79.1	79.0	78.8	79.0
IP Turbine Efficiency Corrected	%		90.5	90.5	90.3	89.8	90.4
Condenser Pressure	inHga		3.2	2.8	2.5	1.7	3.0
Circ Water Temp to Condenser	DEGF		80.0	70.8	63.2	39.9	82.3
Air Heater Gas Outlet Temp	DEGF		355.2	353.1	338.7	335.7	348
Ambient Air Temp	DEGF		90.4	84.7	75.5	42.2	88.6
Air Temp to Air Heater	DEGF		99.2	93.9	83.1	82.2	
Gas Temp to Air Heater	DEGF		650.4	652.5	653.8	662.0	
Throttle Pressure	PSIG		1317.6	1314.6	1313.8	1315.8	
Throttle Steam Temp	DEGF		949.4	949.4	949.7	950.7	
Superheat Spray Flow	KPPH		5.9	8.3	6.3	20.4	
Reheat Steam Temp	DEGF		950.0	949.8	949.6	950.0	
Reheat Spray Flow	KPPH		13.4	14.5	14.8	20.8	
Excess Oxygen	%		2.0	2.1	2.2	2.3	
Carbon Monoxide	PPM		499.5	589.2	556.6	369.1	
Feedwater Flow	KPPH		1046.8	1049.7	1050.0	1050.7	1027.2
Steam Flow	KPPH		1075.9	1073.8	1072.0	1071.8	
Feedwater/Steam Flow 1.00 prior to 2/10			0.973	0.977	0.979	0.980	

Unit 2 heat rate is slightly up from previous months and is felt due to increased backpressure.


Meramec Unit 2 - Corrected Load and Turb Efficiencies
Corrected Load (MWs)
%
Standard load = 136.46MWs
135
130
125
120
115
110
95.00
90.00
85.00
80.00
75.00
70.00
Jan-08 Feb-08 Mar-08 Apr-08 May-08 Jun-08 Jul-08 Aug-08 Sep-08 Oct-08 Nov-08 Dec-08 Jan-09 Feb-09 Mar-09 Apr-09 May-09 Jun-09 Jul-09 Aug-09 Sep-09 Oct-09 Nov-09 Dec-09 Jan-10 Feb-10 Mar-10 Apr-10 May-10 Jun-10 Jul-10
Corr Load
HP Eff
IP Eff


Meramec Unit 2 - HP IP Corrected Stage Pressures
First Stage pressure
13th stage
Cold reheat pressure
Hot reheat pressure
Heater 2 extraction, 25th stg
Cross-under, Htr 3 Extr., 30th
Pressure (HP Inlet) (psia)
Pressure (All Others) (psia)
1200
1100
1000
900
800
700
600
500
500
450
400
350
300
250
200
150
100
50
0
Jan-08 Feb-08 Mar-08 Apr-08 May-08 Jun-08 Jul-08 Aug-08 Sep-08 Oct-08 Nov-08 Dec-08 Jan-09 Feb-09 Mar-09 Apr-09 May-09 Jun-09 Jul-09 Aug-09 Sep-09 Oct-09 Nov-09 Dec-09 Jan-10 Feb-10 Mar-10 Apr-10 May-10 Jun-10 Jul-10

Summary of Performance Report for:

Plant	Meramec						
Unit	3						
Period	6/1/10 to	7/1/10					
		Jun-10	May-10	Apr-10	Mar-10	Jun-09	
Full Load Performance							
Hours of Data (>90% Monthly Capability or CVP>90%)		385	241	277	347	291	

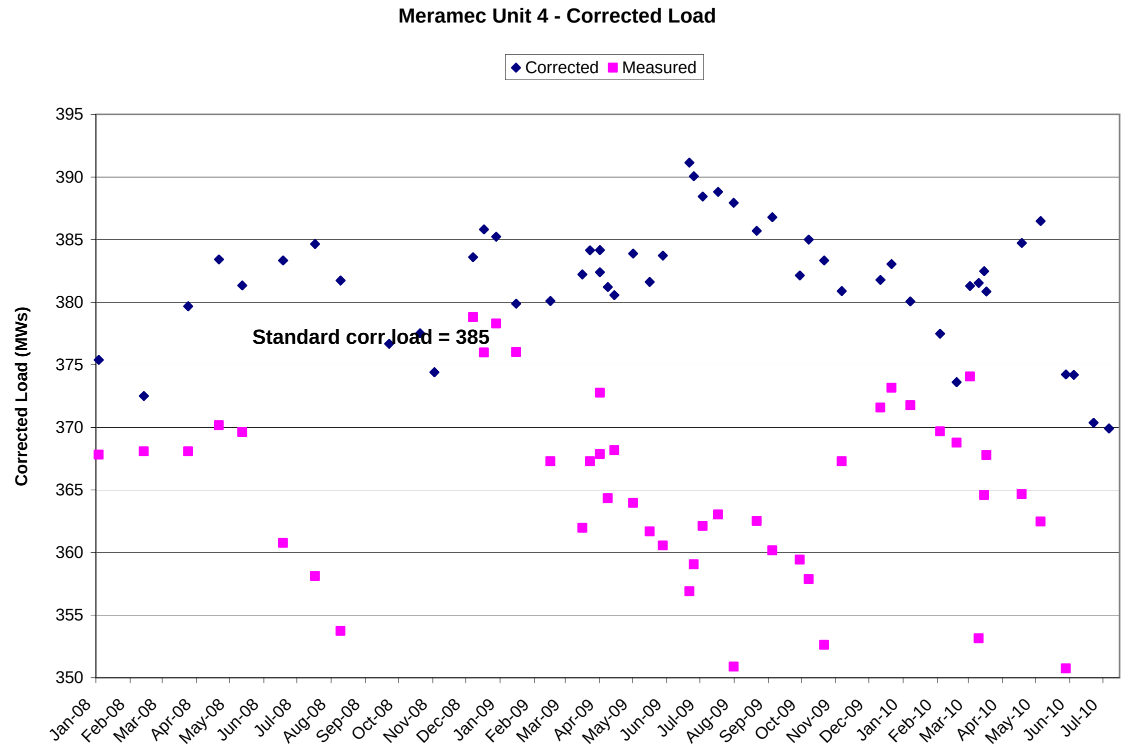
		Averages	**Averages**	**Averages**	**Averages**	**Averages**
Generator Megawatts	MW	284.3	284.8	290.9	290.5	283.7
Aux Power	MW	19.3	19.1	19.1	18.8	18.8
Aux Power	%	6.8	6.7	6.6	6.5	6.6
Net Load	MW	265.0	265.7	271.8	271.7	264.8
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR	11683.1	11590.6	11517.5	11566.0	11736
Gross Unit Heat Rate	BTU/KW-HR	10888.2	10814.3	10760.5	10816.4	10957
Boiler Efficiency Actual	%	83.6	83.5	83.4	83.2	82.8
Gross Turbine Heat Rate	BTU/KW-HR	9107.5	9025.5	8970.8	9000.5	9067
Control Valve Position	%	91.7	91.3	92.8	92.9	86.5
Feedwater Temp To Economizer	DEGF	478.1	477.9	479.5	478.4	479
Feedwater Temp To Htr 1	DEGF	395.3	394.7	395.3	393.6	396
HP Turbine Efficiency Actual	%	80.3	80.3	80.5	81.0	80.1
IP Turbine Efficiency Corrected	%	68.7	69.3	69.4	68.6	69.5
Condenser Pressure	inHga	3.4	2.9	2.9	2.5	3.0
Circ Water Temp to Condenser	DEGF	82.3	69.7	63.8	46.4	80.0
SH Furnace O2	%	1.7	1.9	2.1	1.9	
Air Heater A (SH) Gas Inlet Temp	DEGF	853.7	858.0	849.3	859.1	
Air Heater A (SH) Gas Outlet Temp	DEGF	413.2	408.6	406.6	396.8	411
Air Heater A (SH) CEMT	DEGF	255.8	248.7	244.1	230.3	
RH Furnace O2	%	1.6	2.1	2.2	2.2	
Air Heater B (RH) Gas Inlet Temp	DEGF	726.9	724.8	725.9	729.4	
Air Heater B (RH) Gas Outlet Temp	DEGF	345.1	338.5	334.0	327.2	379
Air Heater B (RH) CEMT	DEGF	220.1	212.2	206.5	195.1	
Ambient Air Temp	DEGF	86.8	76.8	71.3	52.3	84.9
Carbon Monoxide	PPM	652.8	629.0	571.4	430.9	
Throttle Pressure	PSIG	1915.2	1896.7	1896.5	1890.2	
Throttle Steam Temp	DEGF	1001.6	1003.7	1005.7	1000.0	
Superheat Spray Flow	KPPH	130.0	130.8	125.5	125.4	
Reheat Steam Temp	DEGF	999.9	996.9	997.1	1000.4	
Reheat Spray Flow	KPPH	96.1	101.0	102.0	100.1	
Feedwater Flow	KPPH	1980.6	1960.0	2004.8	2005.7	
Steam Flow	KPPH	2092.7	2065.7	2109.0	2104.2	
Feedwater + Spray/Steam Flow		1.009	1.012	1.010	1.013	

Unit 3 heat rate is up slightly from previous months and felt mostly due to increased backpressure.

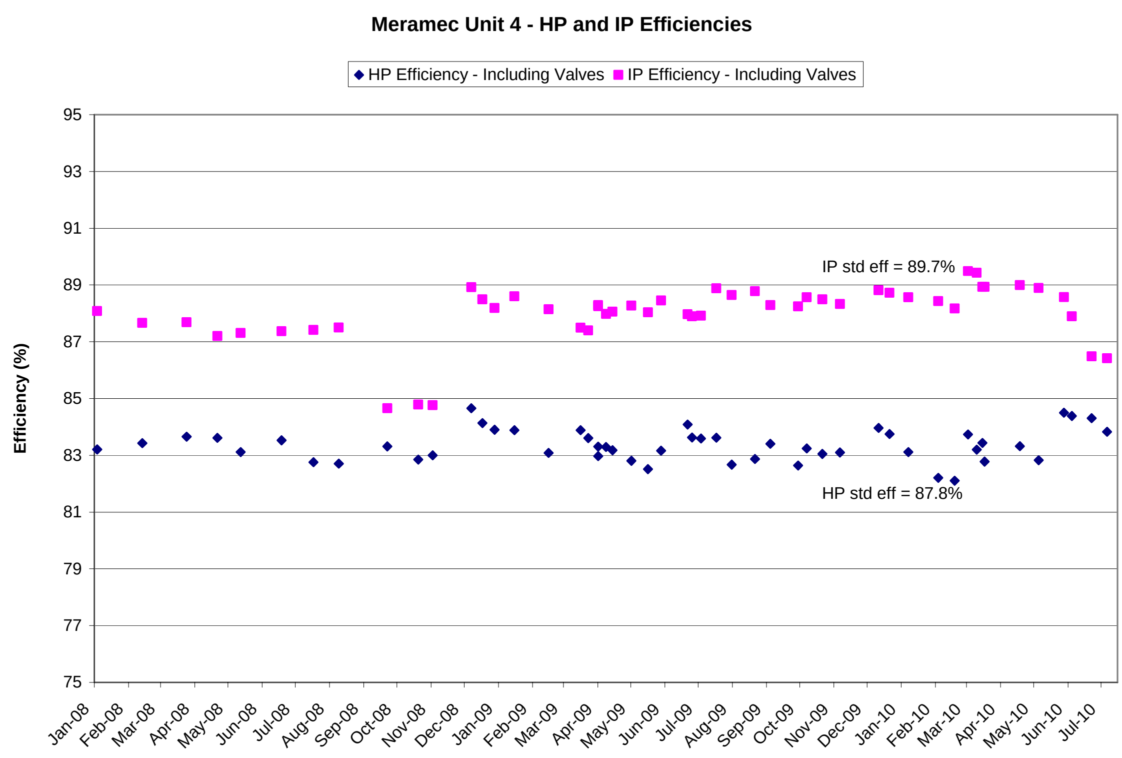
Summary of Performance Report for:

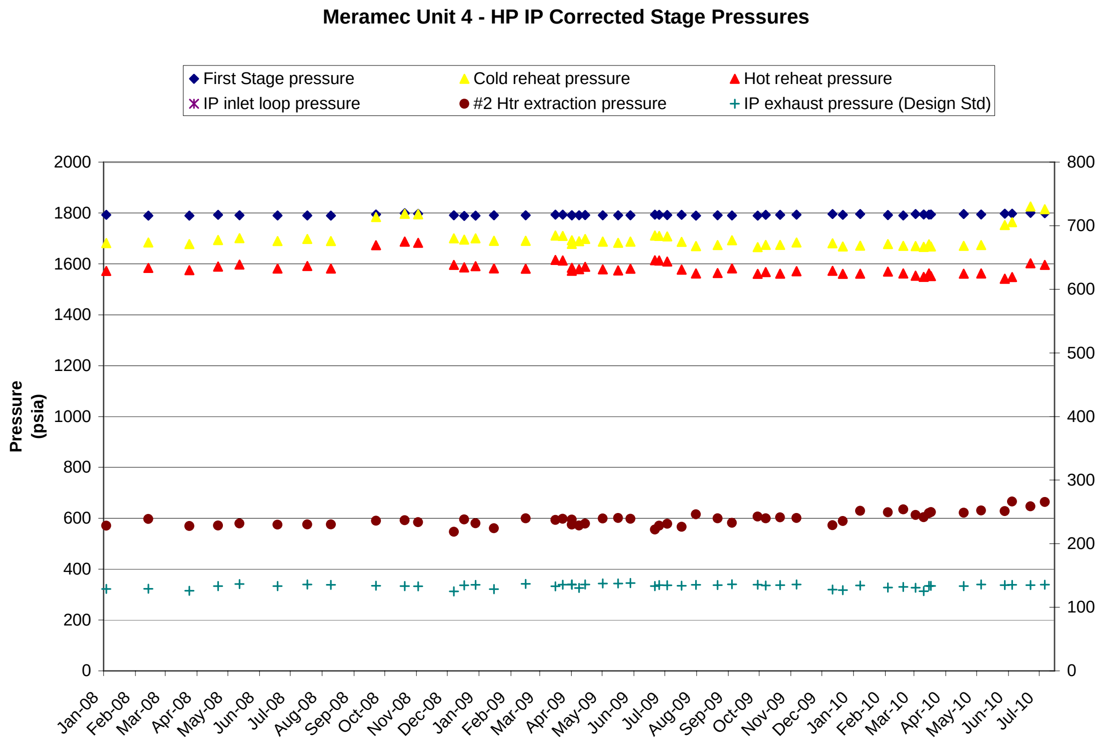
Plant	Meramec						
Unit	4						
Period	6/1/10	to	7/1/10				
			Jun-10	May-10	Apr-10	Mar-10	Jun-09
<u>Full Load Performance</u>							
Hours of Data (>97% CV Position and >90% Capability)			512	431	318	247	309
			Averages	**Averages**	**Averages**	**Averages**	**Averages**
Generator Megawatts	MW		337.3	353.8	359.8	357.0	354
Aux Power	MW		21.3	21.6	21.1	20.5	21.5
Aux Power	%		6.3	6.1	5.9	5.8	6.1
Net Load	MW		316.1	332.2	338.7	336.5	332
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		11083.1	10581.7	10418.9	10430.1	10466
Gross Unit Heat Rate	BTU/KW-HR		10384.8	9935.7	9806.7	9830.3	9829
Boiler Efficiency Actual	%		81.6	82.6	83.1	82.7	83.4
Gross Turbine Heat Rate	BTU/KW-HR		8471.0	8211.3	8151.8	8129.3	8201
Control Valve Position	%		99.7	99.8	99.8	99.8	99.8
Feedwater Temp To Economizer	DEGF		495.9	493.3	491.1	490.2	490
Feedwater Temp To Htr 1	DEGF		397.2	396.0	396.5	393.9	389
HP Turbine Efficiency Actual	%		84.3	84.0	83.3	83.3	83.5
IP Turbine Efficiency	%		88.0	90.0	90.6	90.9	89.3
Condenser Pressure	inHga		3.3	2.8	2.9	1.9	3.4
Circ Water Temp to Condenser	DEGF		82.2	68.9	63.4	46.7	81.5
Air Heater A Gas Inlet Temp	DEGF		731.9	729.1	730.9	736.1	
Air Heater A Gas Outlet Temp	DEGF		358.7	350.2	345.3	341.8	350
Air Heater A CEMT	DEGF		184.3	205.3	221.3	203.8	
Air Heater B Gas Inlet Temp	DEGF		736.8	735.6	730.3	714.9	
Air Heater B Gas Outlet Temp	DEGF		339.9	335.1	330.9	324.6	340
Air Heater B CEMT	DEGF		229.2	221.8	217.1	212.4	
Ambient Air Temp	DEGF		85.7	74.1	69.1	52.0	84.0
Throttle Pressure	PSIG		1999.2	2014.9	2013.6	1984.4	
Throttle Steam Temp	DEGF		996.4	991.8	990.1	978.3	
Superheat Spray Flow	KPPH		222.9	224.7	261.8	275.1	
Reheat Steam Temp	DEGF		999.0	998.9	1001.2	1006.4	
Excess Oxygen	%		2.4	2.5	2.5	2.5	
Carbon Monoxide	PPM		1744.3	1940.8	1887.2	1992.1	
Feedwater Flow	KPPH		2306.9	2336.5	2310.6	2265.5	
Steam Flow	KPPH		2751.9	2777.0	2787.4	2770.9	
Feedwater+Spray/Steam Flow			0.919	0.922	0.923	0.917	

The June net unit heat rate is up about 5% from the same period last year and earlier this year. The largest contributor is the increase in turbine heat rate due to the closed IP stop/intercept valves and the partially closed cold reheat check valve. These items occurred mid May and early June. It appears that the turbine heat rate is up about 300 btu/kw-hr due to these affects and at current fuel prices are an increase of about $200/hr or $150,000 per month in production costs.



The data points on the far right show the effect of the intercept valves and CRH check valve on load and efficiency





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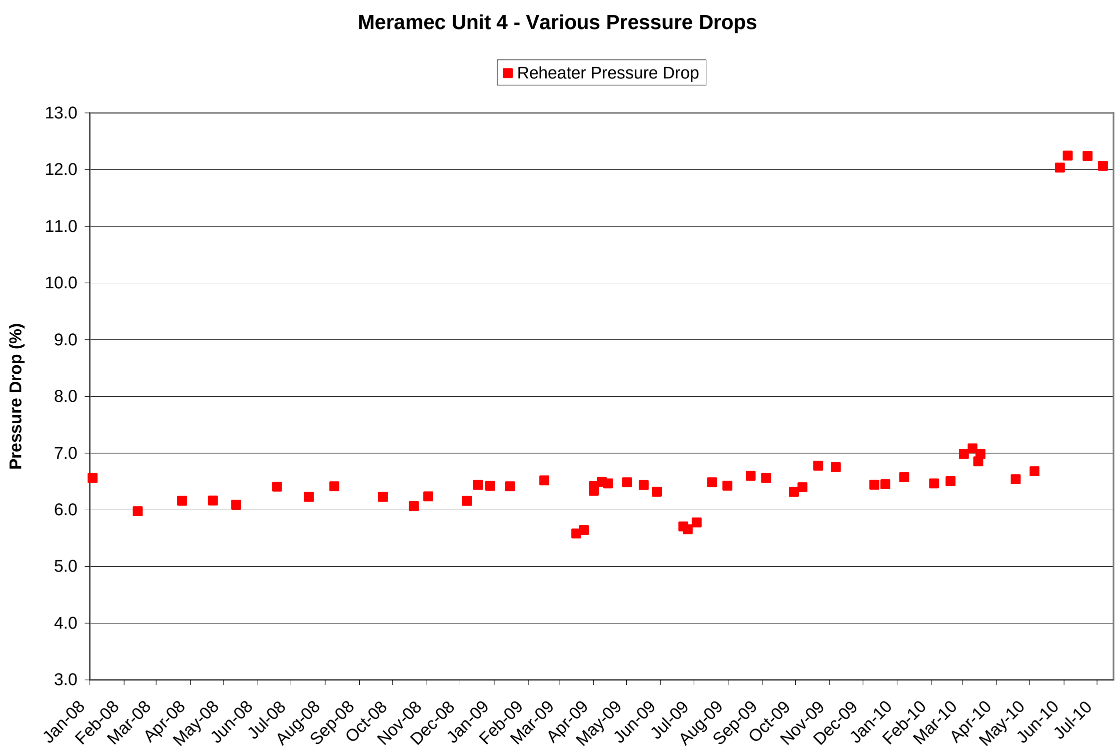


The closed cold reheat check valve is evident in the elevated cold reheat pressure and reheater pressure drop in the above graphs.

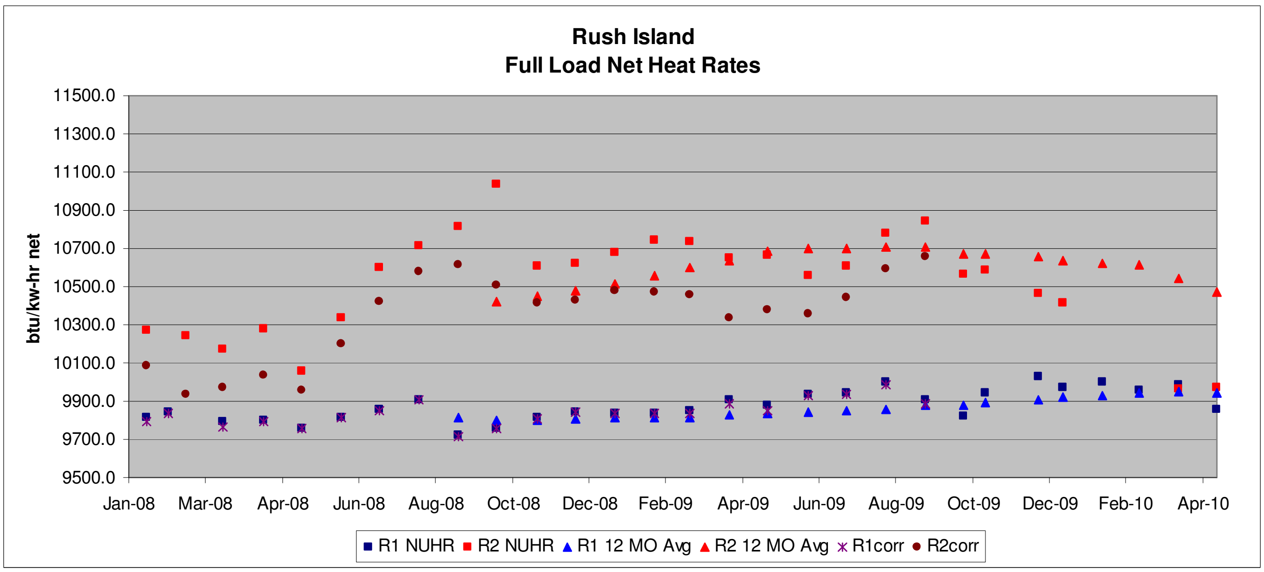
07/25/10

Mr. David Strubberg

From: Jim Barnett

Cc: Meiners, Bob R; Williamson, Andy C; Starks, Paul L; Vasel, Gregory W; Blessing, Gary S; Clonts, Michael D; Wallace, Matthew T; Stuckmeyer, Kenneth B; Clayton, Donald W; Shelton, Jeffrey D; Sind, Joseph J; Hixson, Scott; Tiffin, Glenn J; Kutilek, Fred H; Ziegler, Thomas W; Colter, Jeffrey D; Finnell, Timothy D; McCormack, Scott D; Kobel, Michael J; Maners, Daniel L; Bosch, James J; Sind, Joe J; Nehrkorn, Steve

Subject: Rush Island May 2010 Performance Report



Executive Summary

- As requested by Mr. Sind in the March 2010 Performance Report, Unit 1 start-up/overspeed test was modified in an effort to clean deposits from the LP turbine after the 05/07/10 SBO. Approximately 16.5MW's were re-gained on Unit 1 after this outage.
- Between March and April, performance data pulls for the Rush Island Unit 1 Turbine the IP efficiency increased 0.95% and corrected load on the machine increased 3.8MW's.
- 1-5A Feedwater Heater E-Dump appeared to have increased slightly over the month of May.
- 1-5B Feedwater level remained at zero, but there was a steady increase in the E-Dump valve position to maintain zero level.
- Unit 2 reheater and economizer have met the performance guarantees established by Alstom Power and AmerenUE.
- Unit 2 Low Pressure Turbine replacements have met their performance guarantees established by Alstom Power and AmerenUE.
- Unit 2 Intercept Valve failure is costing the unit approximately 4-6 MW's
- Indicated Feedwater flow on Unit 2 appears to be erroneous because of flow nozzle build up or debris in the line.

Attachment D

- Unit 2 5A/B Feedwater heaters still have a high DCA even after moving the levels to OEM recommended values.

Action Items

- The Instrument & other issue spreadsheet has been updated and JRs initiated for some instruments that are not functional. I:\RUSH\Performance\Instrument & other issues.xls . This list also includes unit 1 condenser vacuum pump flows that went bad quality on 3/8 (1CON15131 and 1CON15132). No JRs could be found for these air leakage instruments.
- Investigate the increase in corrected load and IP turbine efficiency that occurred the first part of April.
- AUE performance(JJS/JDS) engineering is reviewing Alstom's most recent comments on Unit 1 Turbine's nozzle block modification. Alstom commented that a 3% change in area represents only a 0.6% change in flow relationship based on first stage pressure. AUE performance engineering is investigating this correlation.
- As part of the Unit 2 LP turbine acceptance test efforts, a special additional test sequence of best achievable and worst tolerable back pressure operation runs will be planned and requested. This will serve to partially validate Alstom backpressure corrections.
- Obtain cost for chemically cleaning the Unit 2's Feedwater flow nozzle.
- Borrow Sioux Station's GE-Panametric Flow Measurement device to validate Performance Engineering's claim of high feedwater flow indication on Unit 2.
- Complete a more in depth performance test on the Rush Island Unit 2's Boiler and Air Preheater. The plant, performance engineering, and project engineering are a coordinating a test for August 2010.
- Performance engineering to coordinate further testing on feedwater heaters, specifically U1/U2 5A/B heaters.

Heat Rate KPI

The heat rate KPI for 2010 will be a pay KPI and will be fleet based. Below is a table showing the actual performance of all 12 UE coal units through May. This data represents the net heat rate at full load on each unit (where full load is greater than 425 MW gross for the Sioux units and greater than 90% of the monthly capability for the other units).

The individual unit data is combined into a fleet number by weighting the data by full load MWhrs on each unit. The fleet number is shown in the second table below. The AmerenUE goal is to have a fleet based heat rate improvement of 1.0% over the next five years. The 2010 goal was set by reducing the 2009 fleet averaged heat rate by 0.2%. The threshold goal was set equal to the fleet averaged heat rate achieved in 2009 and the maximum goal was set equal to the 2009 fleet averaged value minus 0.4%.

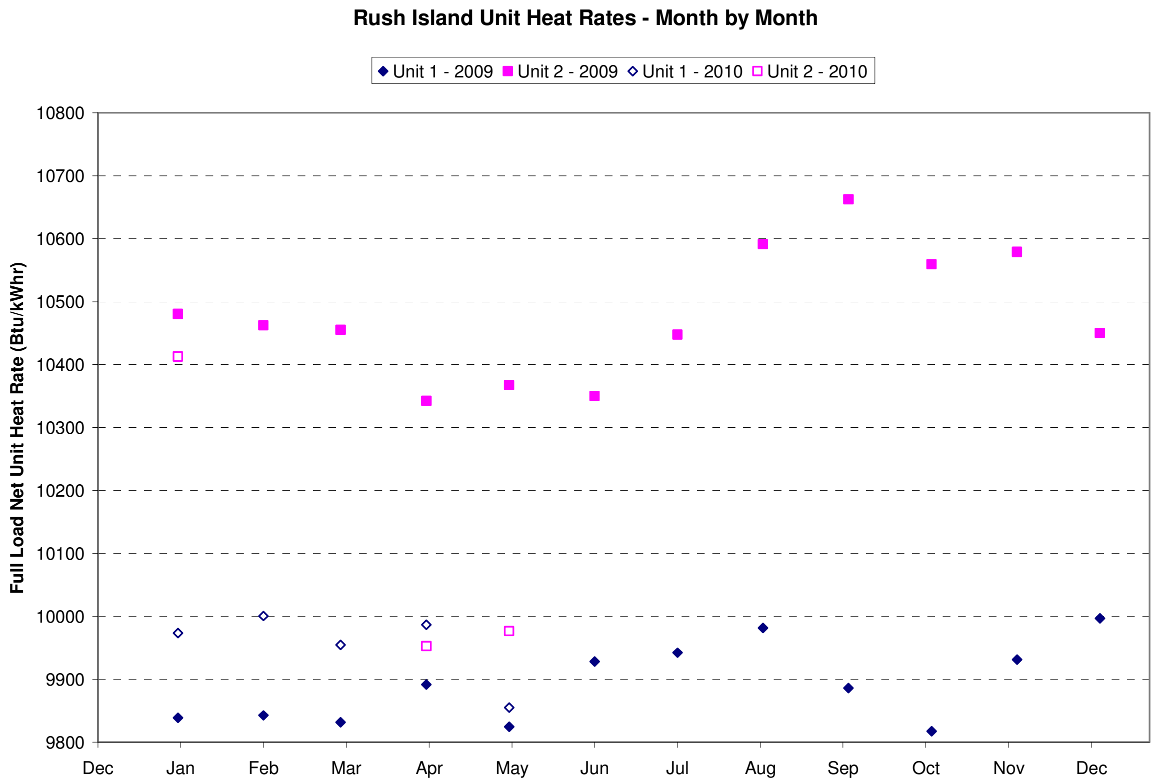
AmerenUE Individual Unit Net Unit Heat Rate at Full Load

Unit	2009 NUHR (Btu/kWhr)	2010 YTD NUHR (Btu/kWhr)	2010 YTD Full Load MWhrs
Labadie 1	9823	9805	1899312
Labadie 2	10214	10272	1519330
Labadie 3	9907	9845	1925248
Labadie 4	9964	9941	1941901
Rush 1	9891	9960	1527543
Rush 2	10482	9981	423680
Sioux 1	9450	9486	1010628
Sioux 2	9925	9833	1012932
Meramec 1	11739	11832	176713
Meramec 2	11821	11593	126796
Meramec 3	11767	11608	576855
Meramec 4	10363	10404	735263

AmerenUE Fleet Averaged Net Unit Heat Rate for Full Load Operation

	2009 NUHR (Btu/kWhr)	2010 YTD NUHR (Btu/kWhr)	2010 Threshold (Btu/kWhr)	2010 Target (Btu/kWhr)	2010 Maximum (Btu/kWhr)
Fleet	10152	10049	10152	10131	10111

The next graph shows the month by month average heat rate values for this year and last year for both Rush Island units. This can be used to compare the performance on the units this year with the same time period last year.



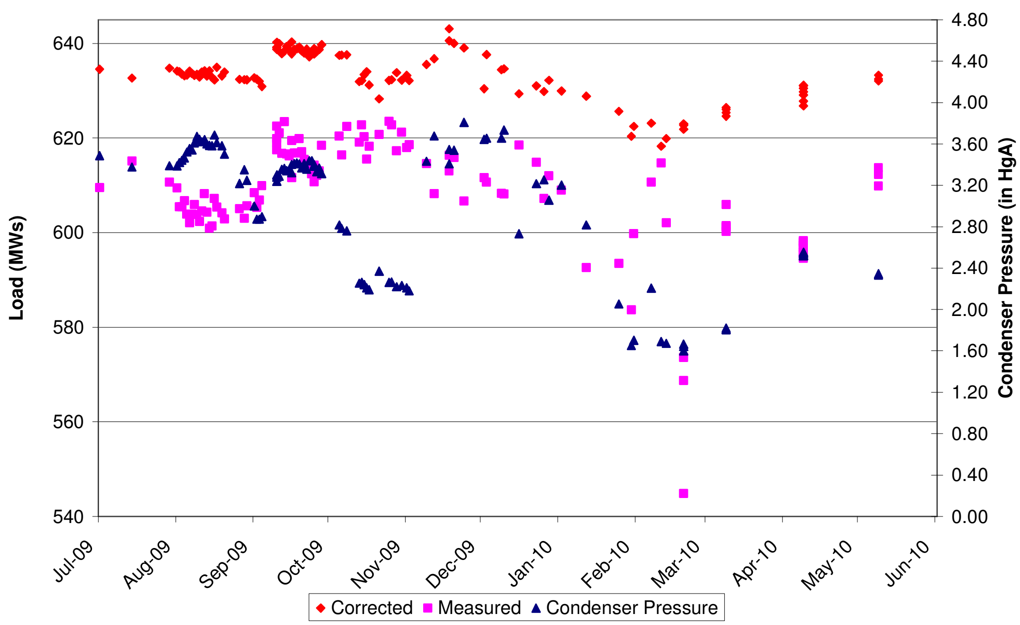
Attachment D

Unit 1 Observations

Summary of Performance Report for:					
Plant	Rush Island				
Unit	1				
Period	5/1/10	to	6/1/10		
			May-10	Apr-10	May-09
Full Load Performance 98%+ GVP					
Hours of Data			8	13	193
			Averages	**Averages**	**Averages**
GENERATOR MEGAWATTS	MW		613.3	596.7	618.5
AUX POWER	MW		30.6	30.2	30.6
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		9847.0	9911.3	9878.0
Boiler Efficiency Actual	%		86.3	86.3	86.2
CONTROL VALVE POSITION LVDT	%		100.6	99.9	100.4
FEEDWATER TEMP TO ECON	degF		493.8	491.7	493.4
FEEDWATER TEMP TO HTR 1	degF		445.2	444.3	444.5
HP Turbine Efficiency Actual	%		84.9	85.3	84.9
IP Turbine Efficiency Corrected	%		89.2	89.4	89.3
Condenser Pressure	inHga		2.1	2.5	2.6
AIRHTR-A GAS OUTLET TEMP	degF		288.2	283.9	300.0
AIRHTR-B GAS OUTLET TEMP	degF		295.2	293.8	309.1
AMBIENT AIR TEMP	degF		60.5	58.1	71.8
CIRC WTR TEMP TO LP CONDB	degF		62.3	58.6	66.6
CIRC WTR TEMP TO LP CONDB	degF		60.6	57.0	64.9
Minimum River Temperature	degF		60.6	57.0	64.9
FWH 1 Temperature Rise	degF		48.6	47.4	49.0
Net Load	MW		582.7	566.5	587.9
Average Exit Gas Temperature	degF		291.7	288.9	304.5
Aux Power	%		5.0	5.1	4.9
Gross Unit Heat Rate	BTU/KW-HR		9355.6	9409.0	9389.2
Gross Turbine Heat Rate	BTU/KW-HR		8073.0	8122.0	8094.9
Measured Feedwater Flow	KPPH		4123.9	4024.6	4156.2
Calc Steam Evaporated	KPPH		4111.5	4021.4	4150.4
Steam Flow From First Stage	KPPH		3959.5	3884.4	3995.2
FW/Steam			1.04	1.04	1.04
Steam/Load			6.46	6.51	6.46
FW/Load			6.72	6.74	6.72
Main Steam Spray	KPPH		9	8	12
Reheat Spray	KPPH		168	167	172

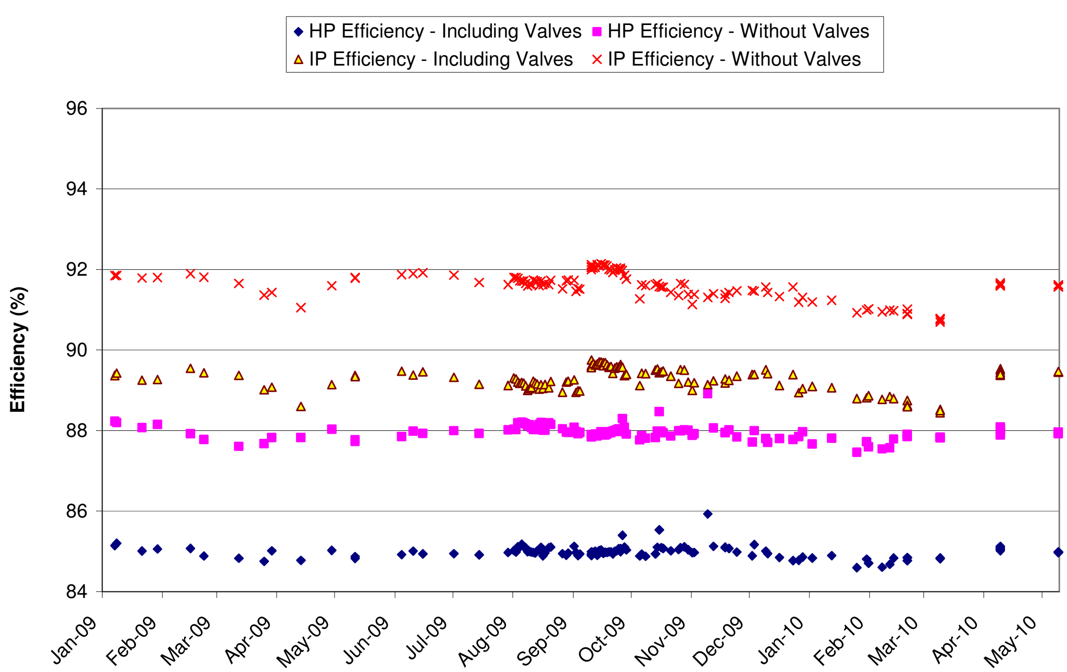
Overall capability for the unit improved for the month of May, while maintaining approximately the same Net Unit Heat Rate. 16.5 MW's were recovered after the short boiler outage, which occurred at the beginning of May. The corrected load on the machine took two step changes one after the SBO and one in early April. The corrected load step change in April is being investigated.

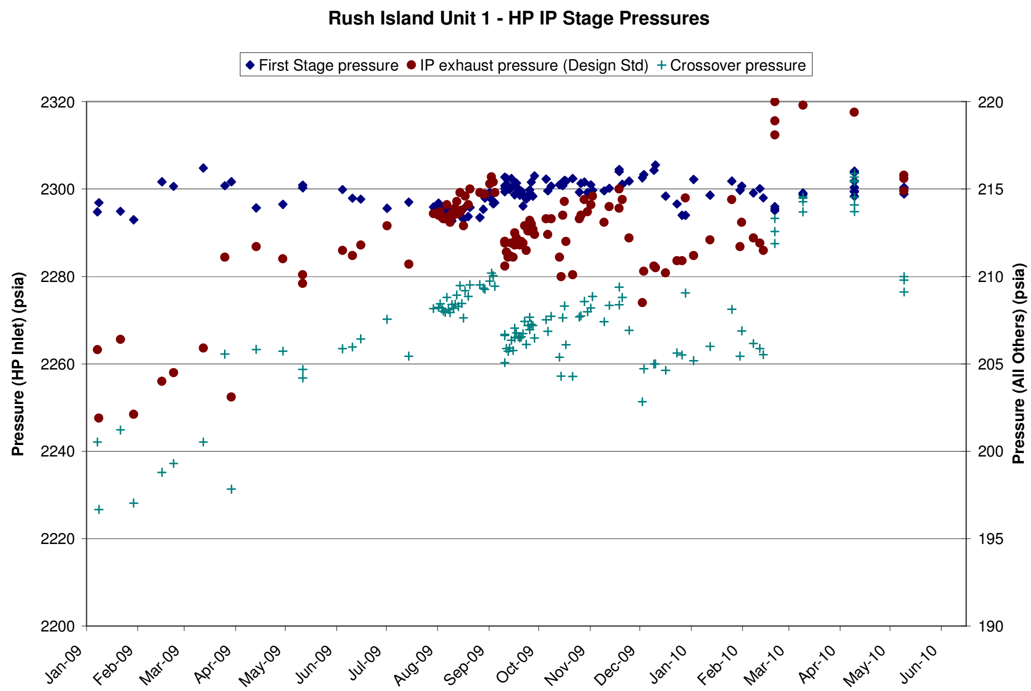
Rush Island Unit 1 - Load and Condenser Pressure



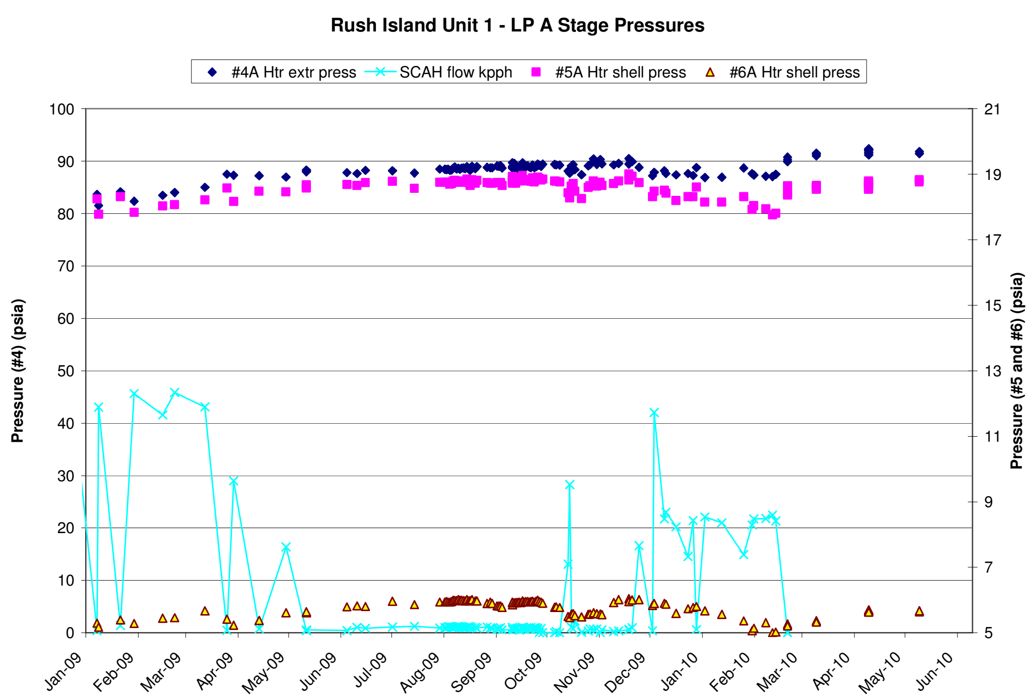
The IP efficiency increased in April and occurred prior to SBO in which corrected load increased significantly. Performance engineering is investigating the cause of this change.

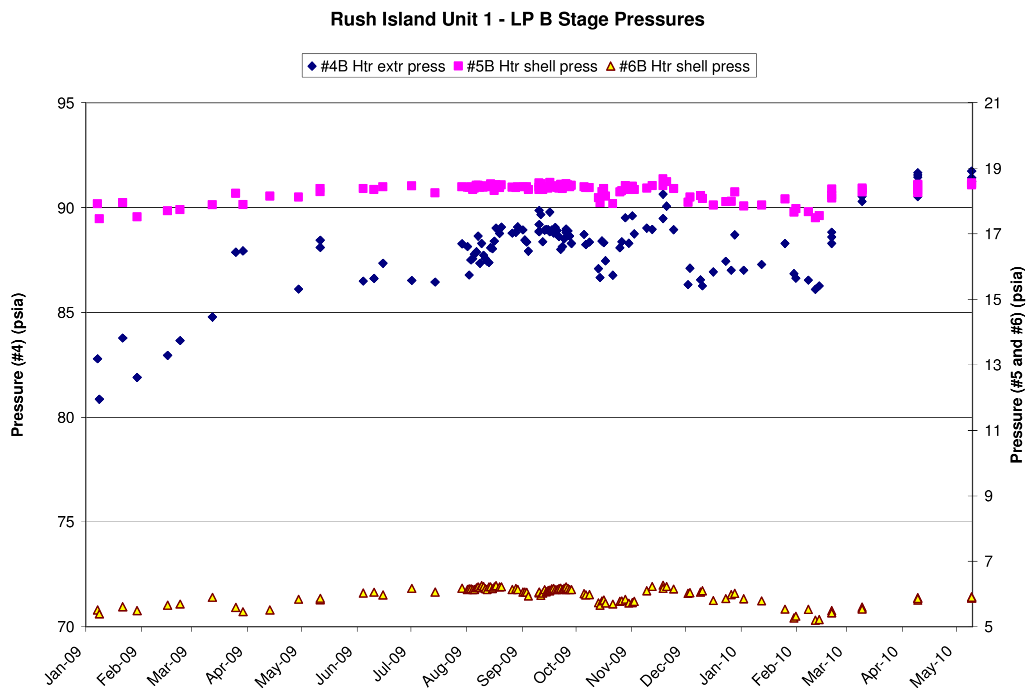
Rush Island Unit 1 - HP and IP Efficiencies

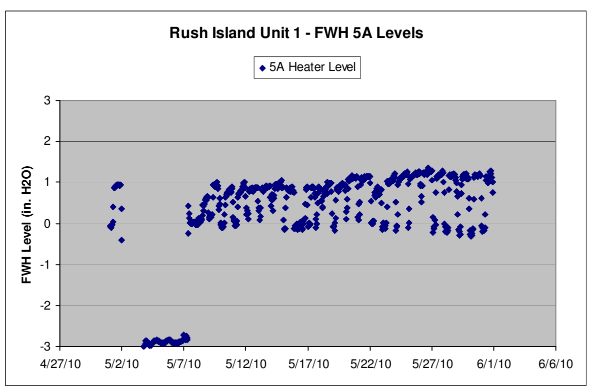




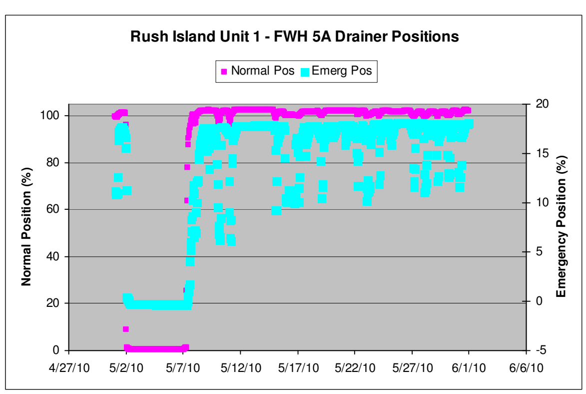
In the trend above you can see the drop in IP exhaust pressure validating that the down stream turbine elements/LPs cleaned up after the SBO.

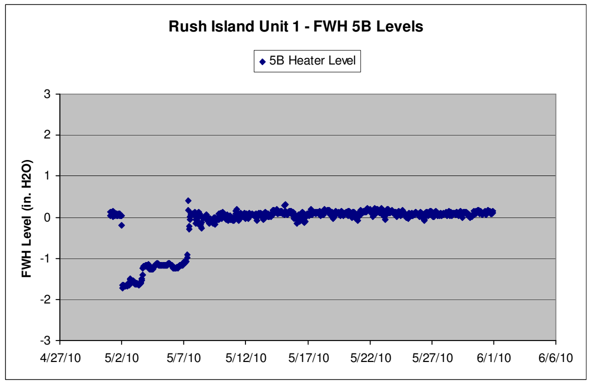




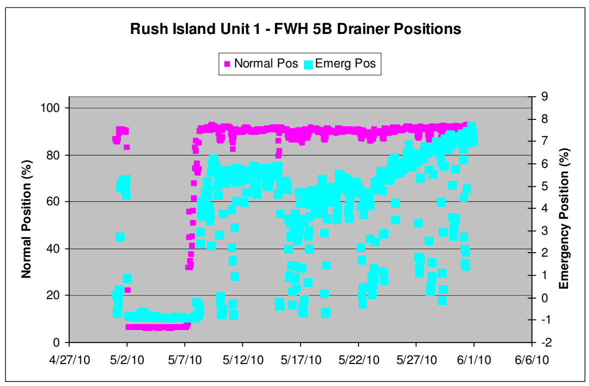


Note that in the figure above, the 5A heater level continues to rise, but in the figure below the valve positions remain constant. The E-dump on the RI heaters are set to start opening if the Normal drainer demand is 80%. The E-dump will not open greater than 20% until a level of 4" is indicated. Therefore, an increasing heater level with the normal drainer 100% open would indicate that this heater has a leak. Performance engineering will continue to monitor and would like for the plant to perform a leak check at their next opportunity.





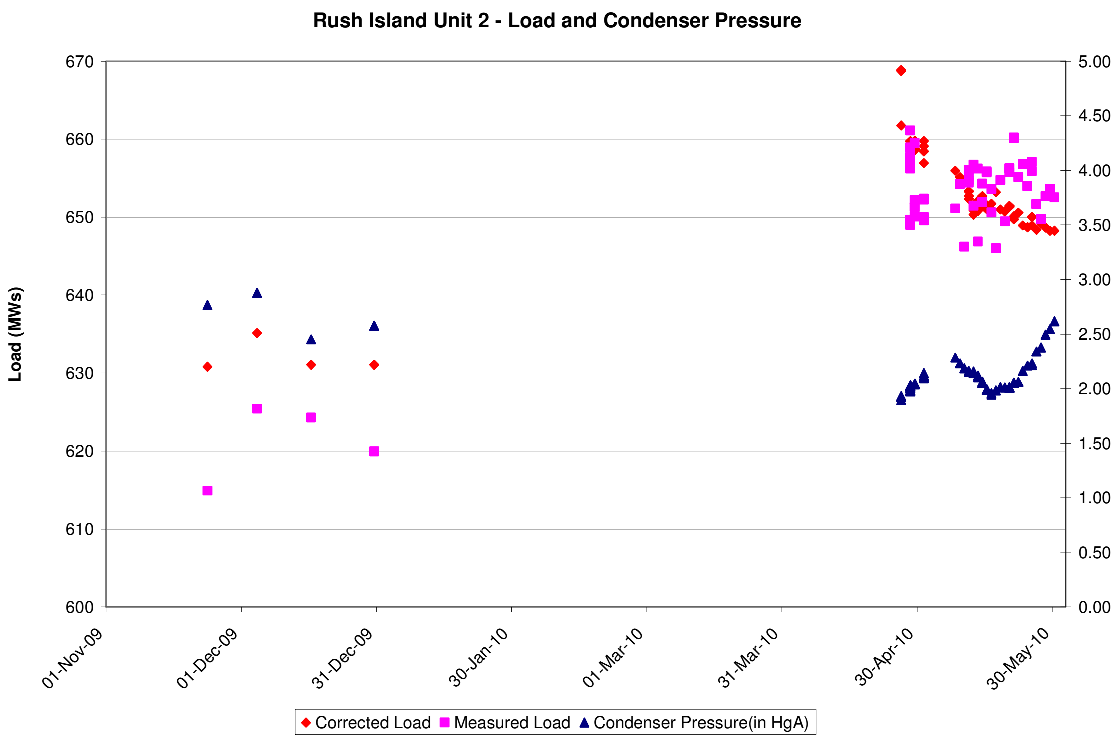
As shown above, the level in the 5B heater remains at 0 inches, but the Normal Drainer and E-dump continue to open further and further to maintain level. This may also indicate a slight leak in this heater.

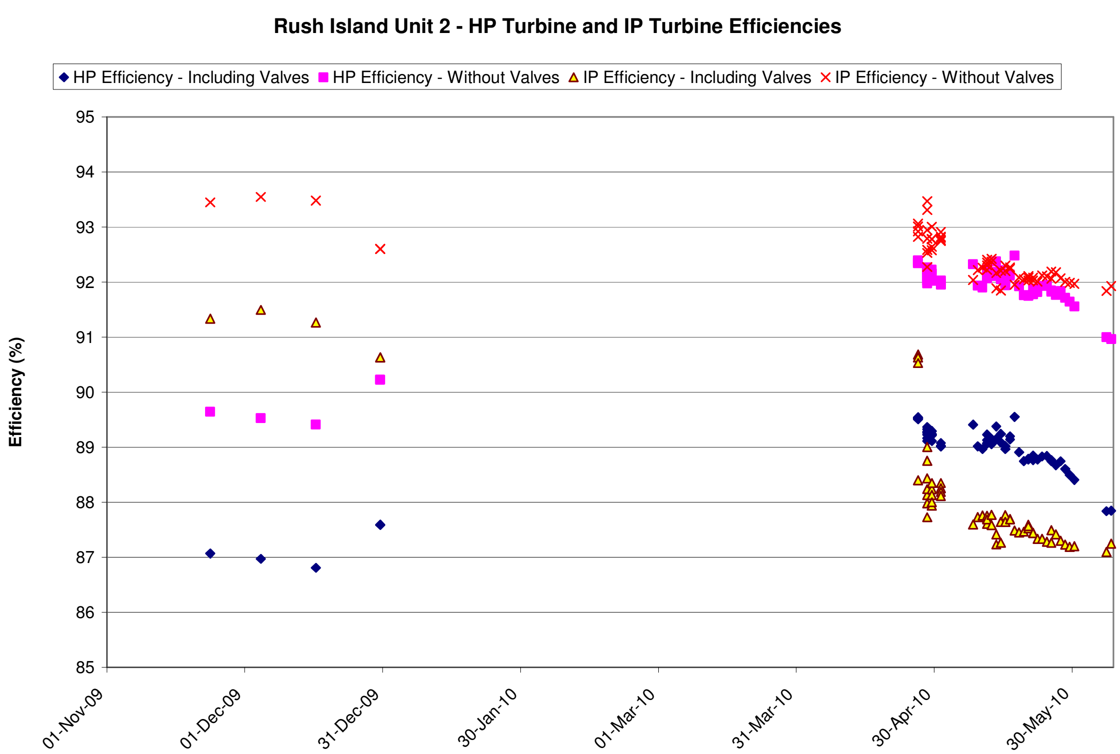


Unit 2 Observations

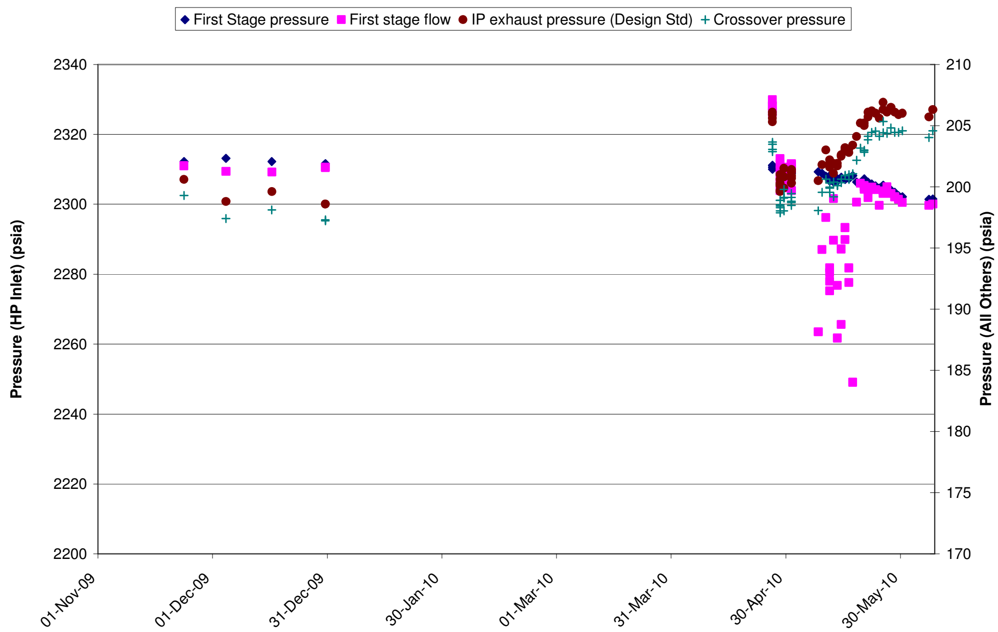
Summary of Performance Report for:

Plant	Rush Island				
Unit	2				
Period	5/1/10	to	6/1/10		
			May-10	Apr-10	May-09
Full Load Performance					
Hours of Data			395	77	178
			Averages	**Averages**	**Averages**
GENERATOR MEGAWATTS	MW		651.9	588.9	612.9
AUX POWER	MW		31.0	28.0	35.8
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		9971.7	9964.2	10663.6
Boiler Efficiency Actual	%		86.3	86.9	85.9
CONTROL VALVE POSITION LVDT	%		100.3	100.6	99.8
FEEDWATER TEMP TO ECON	degF		490.9	477.6	485.9
FEEDWATER TEMP TO HTR 1	degF		446.6	435.0	441.7
HP Turbine Efficiency Actual	%		88.4	89.0	88.0
IP Turbine Efficiency Corrected	%		90.2	91.7	92.5
Condenser Pressure HP	inHga		2.2	1.9	2.0
AIRHTR-A GAS OUTLET TEMP	degF		294.5	266.6	311.4
AIRHTR-B GAS OUTLET TEMP	degF		315.7	293.6	322.1
AMBIENT AIR TEMP	degF		71.8	62.9	72.6
CIRC WTR TEMP TO LP CONDB	degF		65.1	60.9	65.3
CIRC WTR TEMP TO LP CONDB	degF		65.3	60.9	65.2
Minimum River Temperature	degF		65.1	60.9	65.2
FWH 1 Temperature Rise	degF		44.3	42.6	44.2
Net Load	MW		620.9	560.9	577.2
Average Exit Gas Temperature	degF		305.1	280.1	316.8
Aux Power	%		4.8	4.8	5.8
Gross Unit Heat Rate	BTU/KW-HR		9497.8	9490.1	10041.3
Gross Turbine Heat Rate	BTU/KW-HR		8197.8	8243.2	8628.0
Measured Feedwater Flow	KPPH		4522.1	4078.9	4333.3
Calc Steam Evaporated	KPPH		4492.3	4001.8	4394.9
Steam Flow From First Stage	KPPH		4123.5	3649.9	3934.5
FW/Steam			1.097	1.118	1.101
Steam/Load			6.325	6.198	6.419
FW/Load			6.937	6.926	7.070
Main Steam Spray	KPPH		23	92	12
Reheat Spray	KPPH		97.0	74.5	171.5

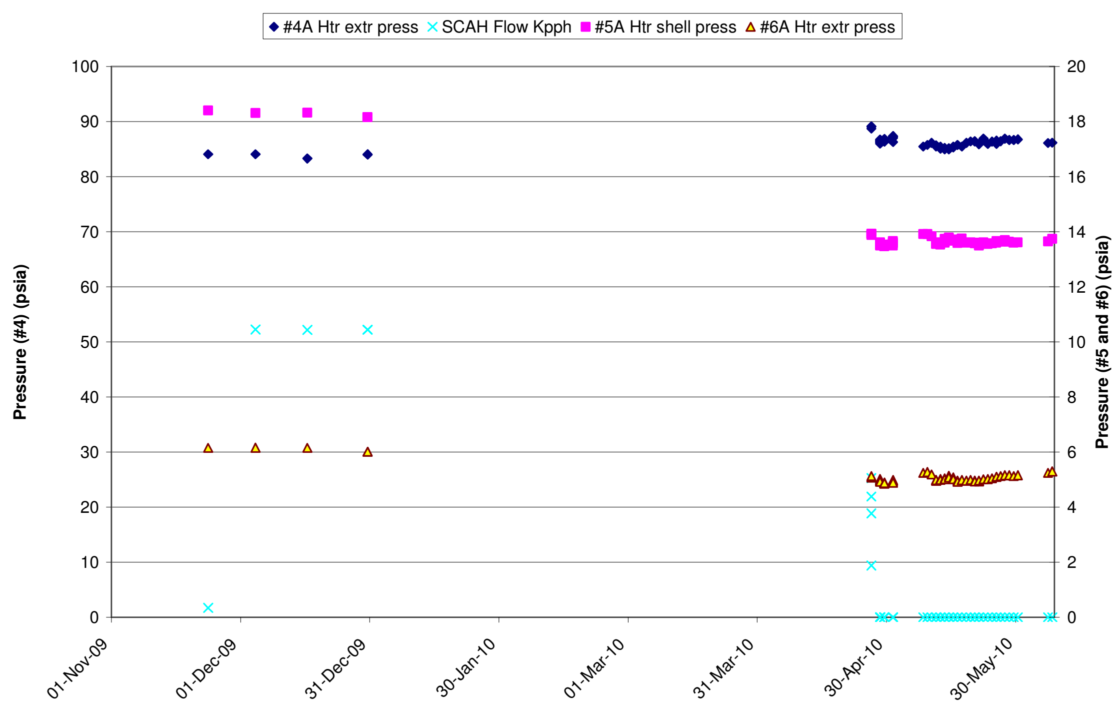

Rush Island Unit 2 - Load and Condenser Pressure
Load (MWs)
670
660
650
640
630
620
610
600
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
01-Nov-09
01-Dec-09
31-Dec-09
30-Jan-10
01-Mar-10
31-Mar-10
30-Apr-10
30-May-10
Corrected Load
Measured Load
Condenser Pressure(in HgA)


Rush Island Unit 2 - HP Turbine and IP Turbine Efficiencies
HP Efficiency - Including Valves
HP Efficiency - Without Valves
IP Efficiency - Including Valves
IP Efficiency - Without Valves
Efficiency (%)
95
94
93
92
91
90
89
88
87
86
85
01-Nov-09
01-Dec-09
31-Dec-09
30-Jan-10
01-Mar-10
31-Mar-10
30-Apr-10
30-May-10

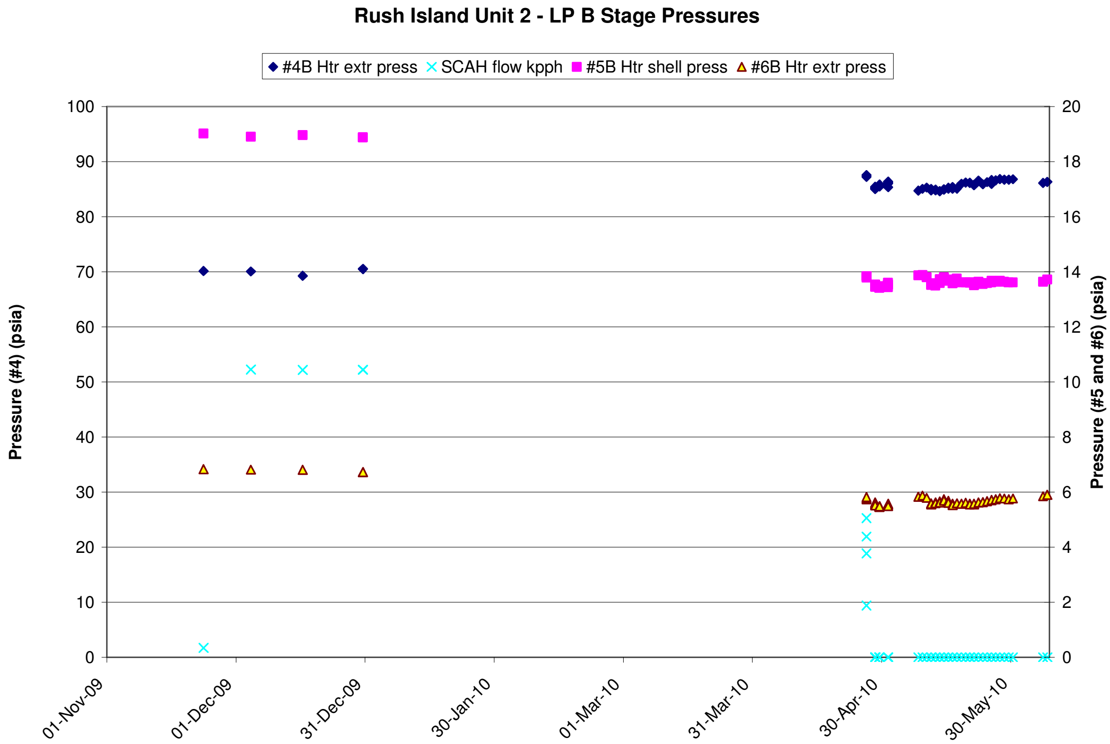
Rush Island Unit 2 - HP IP Stage Pressures



Rush Island Unit 2 - LP A Stage Pressures



Attachment D

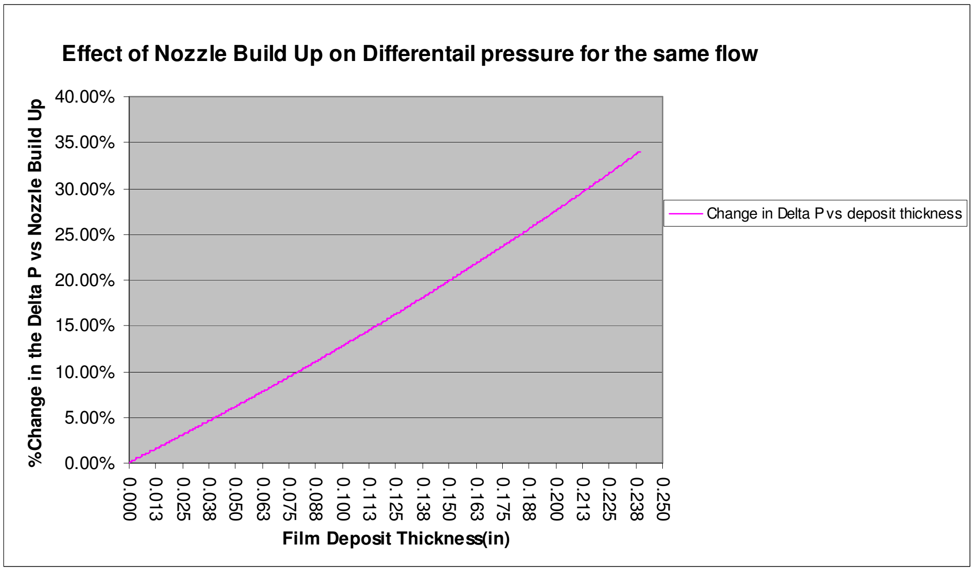


The plot shown above and the plots on the proceeding pages show the trend data from before and after the Unit 2 Major Outage and LP replant. A detailed analysis on the turbine performance since the LP replant was captured in Jeff Shelton's Acceptance Test Report: "Rush Island Unit 2 LP Turbine Retrofit Guarantee Performance Test Report" issued on June 16, 2010.

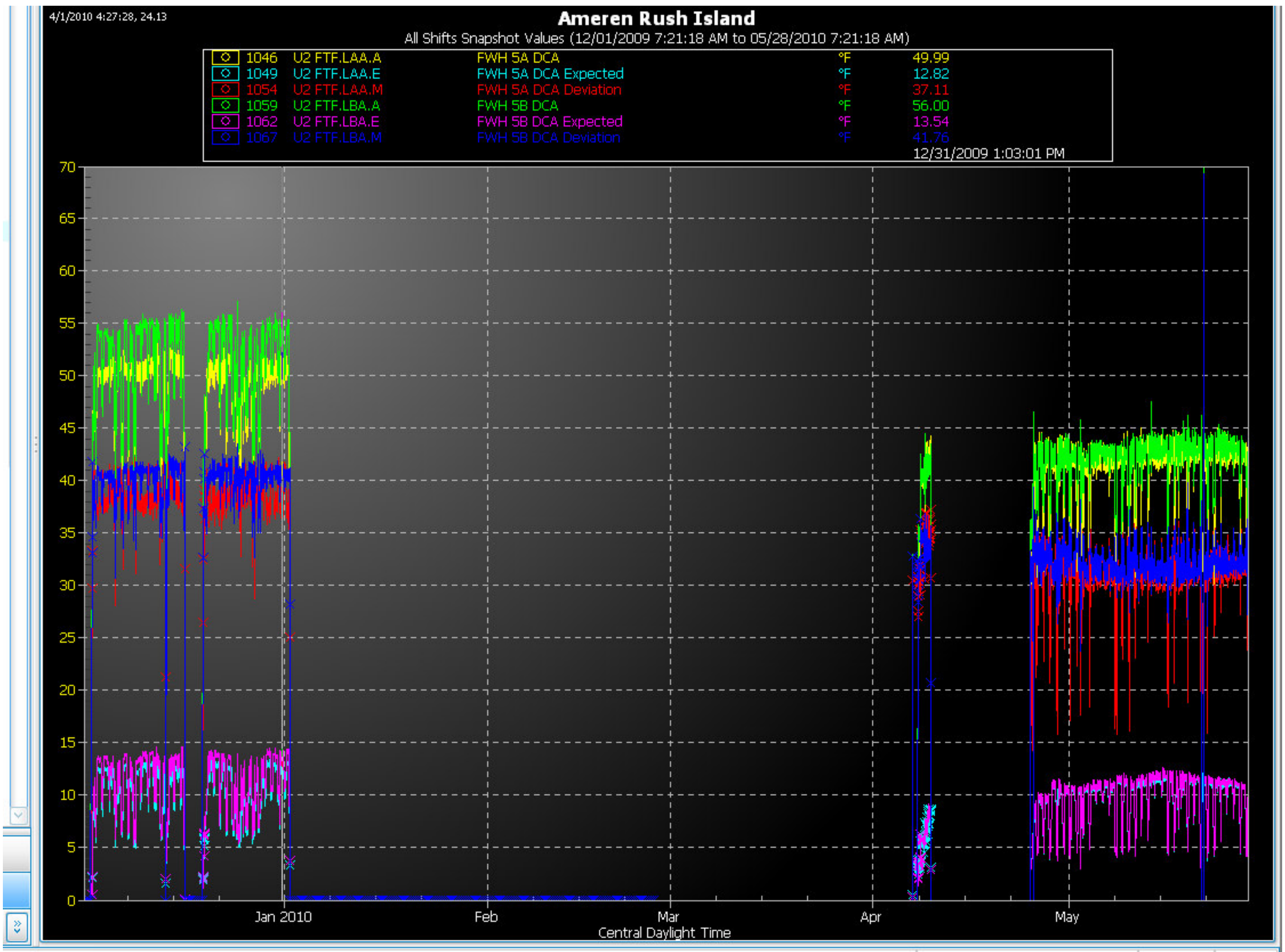
Rush Island Unit 2 boiler was retrofitted with a new economizer and reheater during the 2010 major boiler outage. The performance guarantee included reheat outlet temperature, economizer gas outlet temperature, economizer outlet temperature, economizer gas side differential, and reheater gas side differential. All data is attainable through the plant's PI historian except for the reheater gas side differential. To validate the boiler was well above the performance guarantee, 3 full load periods were selected. The data was obtained over an 8 hour period and averaged in 15 minute data set(s) which is shown in the table below. Based on these results the unit was operated well within the margin on all guarantees. In addition to the sample data sets, a more in-depth performance test will be completed in the Fall of this year.

Variables	Guarantee	Units	Average	Test Data 1	Test Data 2	Test Data 3
Excess Air		%	14.78	14.88	14.81	14.65
Main Steam Flow		kpph	4120.28	4123.30	4118.52	4119.01
RH Flow w/o RH spray		kpph	4172.13	4184.27	4168.98	4163.14
Sh Spray flow		kpph	27.08	9.96	18.39	52.89
RH Spray flow		kpph	113.43	88.75	115.23	136.31
Economizer water flow		kpph	4526.88	4535.19	4524.98	4520.46
Average Economizer Gas Outlet Temperature	684(+20/-0)	F	687.62	684.30	683.91	694.66
Economizer Inlet Water Temperature		F	494.81	493.59	494.82	496.01
Economizer Outlet Wate4r Temperature	646(+0/-7)	F	645.18	645.84	643.69	646.00
Economizer Inlet Water Pressure		psig	2877.68	2879.37	2877.42	2876.24
Air Heater Uncorrected Outlet Gas Temperature		F	307.27	306.46	303.32	312.02
Air Heater Inlet Air Temp		F	93.99	93.80	92.60	95.56
Ambient Air Temperature		F	83.06	82.68	81.87	84.64
Economizer Draft Loss	<3	wg	1.20	1.26	1.23	1.12
Reheater Draft Loss??	<1	wg	#DIV/0!			
Total SH delta P		wg	3.08	3.03	2.97	3.23
SH outlet Temperature		F	1001.81	998.61	1002.57	1004.26
SH outlet Pressure		psig	2464.38	2462.65	2463.93	2466.55
RH outlet Temperature	1005+/-10	F	1008.81	1008.43	1008.78	1009.22
RH inlet Temperature		F	676.71	681.18	677.08	671.86
RH inlet pressure		psig	692.13	689.64	691.52	695.21
RH outlet pressure		psig	642.89	640.35	642.39	645.94
Fuel Input		kpph	727.07	722.20	720.47	738.55
Calculated Total Air Flow		kpph	5040.49	5011.03	4996.10	5114.34

Unit 2 feedwater flow indication continues to remain higher than expected. Performance engineering has reviewed the DCS calculation being completed in the controls and the calculations match Performance Engineering's calculations for the given differential. The chart below shows if the same flow was maintained, but the nozzle ID was decreased, the % change in the differential pressure would be observed. A small film deposit could cause the difference in Feedwater indications on the unit, for example if the flow is actually 6% high, this would indicate about a 0.050" layer of build-up. Performance Engineering is working with Chemical Engineering on obtaining a cost estimate to chemically clean the nozzles in place.



During the U2 MBO the 2-5A/5B levels were changed based on the OEM's latest mechanical drawing to improve the performance of the heaters(i.e. lower DCA back down to what is shown on thermal kits). The move did decrease the DCA by approximately 10F. The correct tube sheet plugging maps have been entered into EtrPro, and the heaters are still operating approximately 30F higher than the EtaPro predicted values. In the next several months, Performance engineering will be working with the plant to conduct tests to validate where the correct operating levels should be set on the 5A/B heaters to maintain the correct level and lower DCA(s).



July 27, 2010

To: Karl Blank
From: Scott Hixson
Cc: Bob Meiners, Keith Stuckmeyer, Pat Weir, Paul Piontek, Greg Gilbertsen, David Azar, Shawn Caradine, Mark Selvog, Steve Garner, Scott McCormack, Lisa Meyer, Ken Stuckmeyer, Don Clayton, Joe Sind, Jim Barnett, Glenn Tiffin, Matt Wallace, Jeff Shelton, Dan Schaeffer, Tim Finnell

Subject: Sioux June 2010 Performance Report

Executive Summary

The most notable items regarding Sioux unit performance were:

- Performance engineering is working to determine Unit 2's load limiting factor from the data obtained from maximum load testing performed over the past two weeks.
- Performance engineering will recommend that some temperature and pressure instruments be calibrated during upcoming outages to ensure the data being used to evaluate equipment performance is as accurate as possible
- June's average river temperature increased approximately 5°F as compared to May. This accounted for approximately 0.51"Hga of the increase in condenser pressure.

Fig. 1 shows the monthly unit heat rates and rolling 12-month average heat rates for both units. Note that the monthly values shown in Figure 1 are for hours in which the average gross load is above 425 MWs.

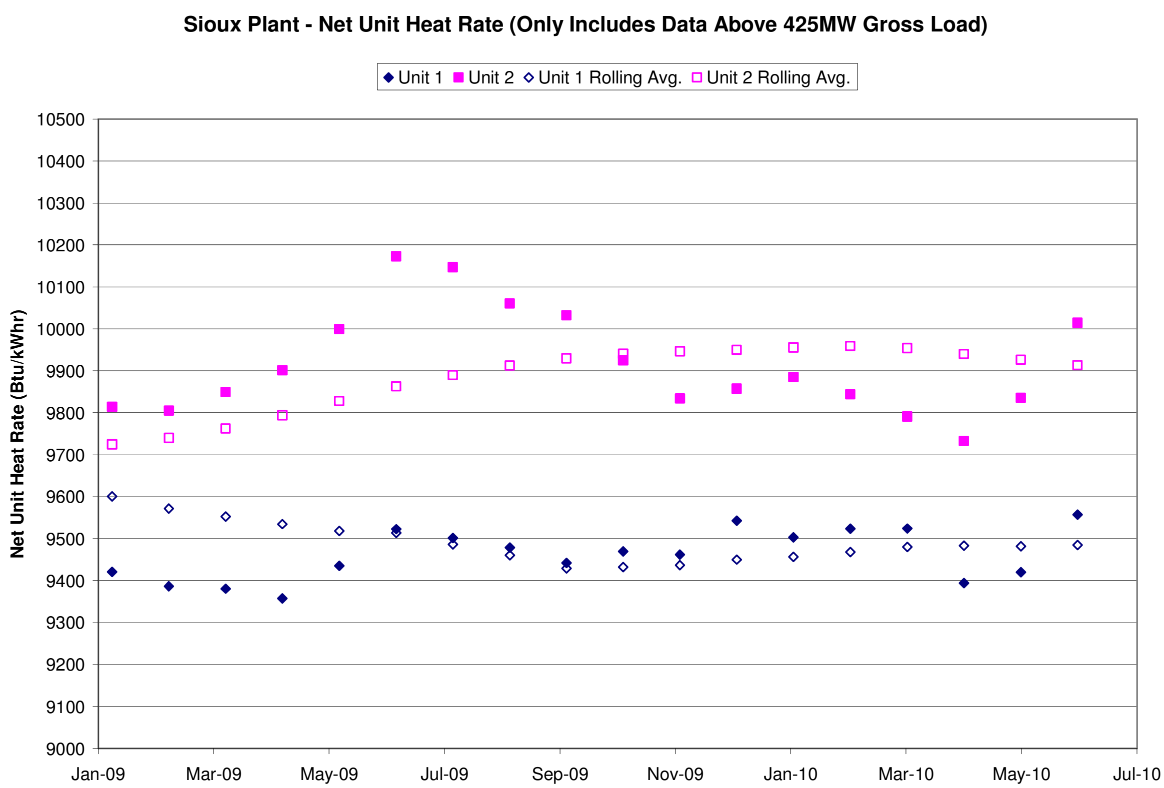


Fig. 1 Individual Unit Heat Rates

Heat Rate KPI

The heat rate KPI for 2010 will be a pay KPI and will be fleet based. Below is a table showing the actual performance of all 12 UE coal units through June. This data represents the net heat rate at full load on each unit (where full load is greater than 425 MW gross for the Sioux units and greater than 90% of the monthly capability for the other units).

AmerenUE Individual Unit Net Unit Heat Rate at Full Load

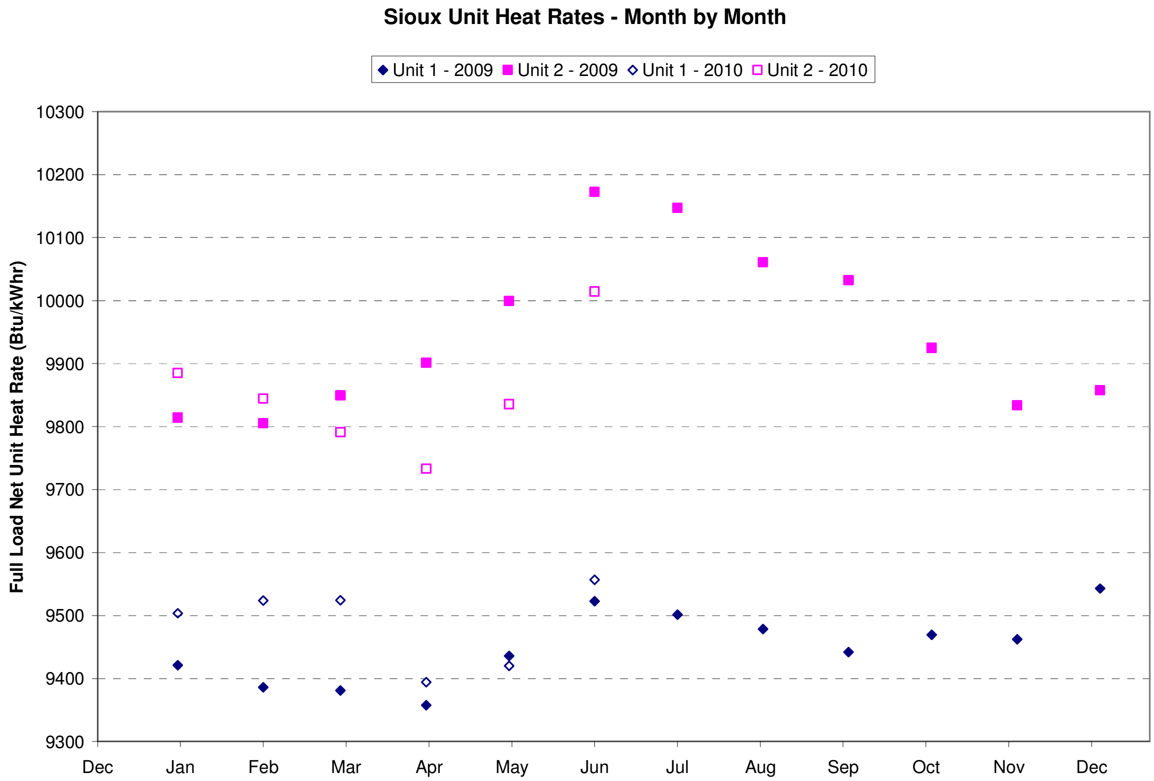
Unit	2009 NUHR (Btu/kWhr)	2010 NUHR (Btu/kWhr)	Full Load MWhrs
Labadie 1	9823	9788	2330249
Labadie 2	10214	10283	1825752
Labadie 3	9907	9857	2333757
Labadie 4	9964	9965	2345011
Rush 1	9891	9952	1795859
Rush 2	10482	10002	770160
Sioux 1	9450	9494	1143781
Sioux 2	9925	9854	1145452
Meramec 1	11739	11832	176713
Meramec 2	11821	11680	169824
Meramec 3	11767	11622	710238
Meramec 4	10363	10534	908323

The individual unit data is combined into a fleet number by weighting the data by full load MWhrs on each unit. The fleet number is shown in the second table below. The AmerenUE goal is to have a fleet based heat rate improvement of 1.0% over the next five years. The 2010 target was set by reducing the 2009 actual heat rate by 0.2%. The threshold goal was set equal to the fleet averaged heat rate achieved in 2009 and the maximum goal was set equal to the 2009 fleet averaged value minus 0.4%.

AmerenUE Fleet Averaged Net Unit Heat Rate at Full Load

	2009 NUHR (Btu/kWhr)	2010 NUHR (Btu/kWhr)	2010 Threshold (Btu/kWhr)	2010 Target (Btu/kWhr)	2010 Maximum (Btu/kWhr)
Fleet	10152	10065	10152	10131	10111

The next graph shows the month by month average heat rate values for this year and last year for both Sioux units. This can be used to compare the performance on the units this year with the same time period last year.



<u>Action Items</u>

- Performance Engineering is working to determine the load limiting factor on Unit 2.
- Performance Engineering will continue investigating the reason behind indicated heat rate difference between the two units.
- Performance Engineering to work with Sioux Operations and Engineering to determine an acceptable turbine efficiency testing procedure.

Unit 1

The following observations were made regarding Unit 1 operation and performance:

- Net Unit Heat Rate is approximately 1.5% higher when compared to May 2010. This is primarily attributed to condenser back pressure increasing increased 0.7"Hga. The heat rate is approximately the same as last year with the most of the difference being attributable to the increased auxiliary load on the unit this year.
- There appears to be several instruments that are not indicating properly on Unit 1. The instruments associated with the PI tags given in the table below should be investigated. Note that the HP Turbine Bowl pressure instrumentation was added to this list. These instruments have had issues in the past but were added here due to their importance in identifying potential valve issues on the unit.

Summary of Performance Report						
Plant	Sioux					
Unit	1					
Period	6/1/10	to	7/1/10			
Full Load Performance			Jun-10		May-10	Jun-09
Hours of Data (Gross load>425 MW)			296		304	116
			Averages		Averages	Averages
Generator Megawatts	MW		449.84		448.10	449.78
Net Load	MW		421.89		420.66	422.99
Aux Power	MW		27.95		27.44	26.78
Aux Power	%		6.21		6.12	5.96
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		9556.98		9419.81	9522.77
Gross Unit Heat Rate	BTU/KW-HR		8963.10		8843.01	9046.14
Gross Turbine Heat Rate	BTU/KW-HR		7939.99		7831.56	7905.47
HP Turbine Efficiency Actual	%		81.58		81.10	81.41
IP Turbine Efficiency Corrected	%		95.74		95.94	96.01
Condenser Pressure	inHga		2.30		1.60	2.27
River Temperature	degF		76.51		64.68	77.03
Boiler Efficiency Actual	%		88.59		88.56	88.39
Average Exit Gas Temperature	degF		306.72		301.54	315.75
Ambient Air Temperature	degF		81.83		74.09	86.91
Feedwater Flow	KPPH		2904.13		2845.76	2871.93
Feedwater Temp To Econ	degF		467.54		465.78	467.83
Feedwater Temp To HTR 1	degF		400.81		399.39	400.83
FWH 1 Temperature Rise	degF		66.73		66.39	67.00
Control Valve Position LVDT	%		26.59		25.75	26.89

Potential Instrumentation Issues on Sioux Unit 1

Tag	Issue	Resolution
SX1BFW-FWHTR6A-0001-TI (U1 FDW HTR 6A EXT Temp)	Currently reads 0F. The indication appeared to work briefly in early December but went back to 0 on Dec. 11, 2009.	
SX1AHS-AHNAIROUT-0001-PI (U1 AIR HTR N AIR OUT PRESS)	Appears to have gone bad on 3/14/2010	
SX1BFW-FWHTR4BLVLCTRL-505V1-ZI (U1 FDW HTR 4B LVL CTRL VLV 505V1 POS)	This appears to be reading low since the 2008 MBO.	
SX1PMS-STACKFLOW-0001-FI (U1 STACK FLOW)	Mr. Gilbertsen has stated that he will investigate the stack flow values on both units.	
SX1TRB-HPTRBSTLRBOWL-0002-PI (HP Bowl Pressure)	Last functional 12/7/07	
SX1TRB-HPTRBSTLRBOWL-0002-PI (HP Bowl Pressure)	Last functional 12/7/07	

Unit 2

The following observations were made regarding Unit 2 operation and performance:

- Net Unit Heat Rate is approximately 1.8% higher when compared to May 2010. This is primarily attributed to condenser back pressure increasing increased 0.68"Hga. Note that heat rate this June is approximately 1.5% lower than what it was last June. The majority of this difference is due to a much lower backpressure on the unit this year.
- There appears to be several instruments that are not indicating properly on Unit 2. The instruments associated with the PI tags given in the table below should be investigated. Note that the HP Turbine Bowl pressure instrumentation was added to this list. These instruments have had issues in the past but were added here due to their importance in identifying potential valve issues on the unit.

Summary of Performance Report						
Plant	Sioux					
Unit	2					
Period	6/1/10	to	7/1/10			
Full Load Performance			Jun-10		May-10	Jun-09
Hours of Data (Gross load>425 MW)			299		304	116
			Averages		Averages	Averages
GENERATOR MEGAWATTS	MW		443.21		442.44	443.70
Net Load	MW		418.31		417.98	416.80
Aux Power	MW		24.90		24.46	26.89
Aux Power	%		5.62		5.53	6.06
Net Unit Heat Rate Actual (GPHI)	BTU/KW-HR		10014.48		9835.38	10172.69
Gross Unit Heat Rate	BTU/KW-HR		9451.85		9291.74	9652.64
Gross Turbine Heat Rate	BTU/KW-HR		8353.12		8212.61	8408.49
HP Turbine Efficiency Actual	%		82.67		81.89	81.97
IP Turbine Efficiency Corrected	%		92.18		92.23	92.14
Condenser Pressure	inHga		2.72		2.04	3.33
River Temperature	degF		85.57		72.42	85.41
Boiler Efficiency Actual	%		88.38		88.39	88.11
Average Exit Gas Temperature	degF		303.11		298.53	314.32
Ambient Air Temperature	degF		82.92		72.98	87.75
Feedwater Flow Rate	KPPH		3022.00		2954.79	0.00
Feedwater Temp To Econ	degF		468.11		466.47	469.89
Feedwater Temp To HTR 1	degF		402.87		401.38	404.47
FWH 1 Temperature Rise	degF		65.24		65.09	65.42
Control Valve Position LVDT	%		28.85		27.95	26.57

There appears to be several instruments that are not indicating properly on Unit 2. The instruments associated with the PI tags given in the table below should be investigated

Potential Instrumentation Issues on Sioux Unit 2

Tag	Issue	Resolution
SX2BFW-FWHTR7ADRN-0001-TI (7A Drain Temperature)	7A Drain temp - Not reading	
SX2BFW-FWHTR5ALVLCTRL-506V1-ZI (U2 FDW HTR 5A LVL CTRL VLV 506V1 POS)	Not reading since the SBO in March	
SX2PMS-STACKFLOW-0001-FI (STACK FLOW U2)	Mr. Gilbertsen has stated that he will investigate the stack flow values on both units.	
SX2TRB-HPTRBSTLRBOWL-0002-PI (HP Bowl Pressure)	Last functional 9/2/09	
SX2TRB-HPTRBSTLRBOWL-0001-PI (1^{st} Stage Lower Left Blow Pressure)		

Unit 2 NeuCo Performance Optimizer Update

During an early June telecom with NeuCO, they were reminded that the calculated unit heat rate for Sioux 2 was better than design and also moving in the wrong direction with load changes. As such, "Corrected Net Turbine Heat Rate Degradation" alerts did not cause any concern, especially since other tools did not indicate such changes. (Note that this was the only alert coming in for weeks). On 6/21 we received notice that they made model changes and alerts should be ignored for a couple of weeks. We had not received any messages from NeuCO to start reviewing alerts again, but on 7/12 received a message that NeuCo planned on tuning the Sioux models, and as of 7/23, received notice that they were still working on it.

AmerenUE
Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 1 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 1 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 1 CTG was conducted and completed on July 12, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 1	
Location	Vandalia, MO	
Date of Test	July 12, 2010	
Time of Test	1000 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	74.5	11.4
1st Hour Reading	74.2	11.4
2nd Hour Reading	74.3	11.4
BTU/cf, Averaged over the two hour run		1012
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11969	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 2 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 2 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 2 CTG was conducted and completed on July 12, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 2	
Location	Vandalia, MO	
Date of Test	July 12, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	73.9	11.4
1st Hour Reading	73.3	11.4
2nd Hour Reading	73.5	11.4
BTU/cf, Averaged over the two hour run		1009
Calculated Heat Rate (BTU/kWh)		
2 hour Average	12146	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 3 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 3 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 3 CTG was conducted and completed on July 15, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 3	
Location	Vandalia, MO	
Date of Test	July 15, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	77	11.9
1st Hour Reading	76.2	11.5
2nd Hour Reading	76.1	11.5
BTU/cf, Averaged over the two hour run		1010
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11947	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

Augus 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 4 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 4 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 4 CTG was conducted and completed on July 16, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 4	
Location	Vandalia, MO	
Date of Test	July 16, 2010	
Time of Test	1000 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	76.7	11.8
1st Hour Reading	76	11.8
2nd Hour Reading	76	11.7
BTU/cf, Averaged over the two hour run		1008
Calculated Heat Rate (BTU/kWh)		
2 hour Average	12091	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 5 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 5 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 5 CTG was conducted and completed on July 13, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 5	
Location	Vandalia, MO	
Date of Test	July 13, 2010	
Time of Test	900 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	77.3	11.7
1st Hour Reading	77	11.6
2nd Hour Reading	75.9	11.5
BTU/cf, Averaged over the two hour run		1009
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11894	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

Ameren UE
Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 6 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 6 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 6 CTG was conducted and completed on July 13, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 6	
Location	Vandalia, MO	
Date of Test	July 13, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	75	12
1st Hour Reading	74.3	11.9
2nd Hour Reading	73.6	11.8
BTU/cf, Averaged over the two hour run		1010
Calculated Heat Rate (BTU/kWh)		
2 hour Average	12607	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE
Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 7 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 7 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 7 CTG was conducted and completed on July 14, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 7	
Location	Vandalia, MO	
Date of Test	July 14, 2010	
Time of Test	900 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	75.1	11.8
1st Hour Reading	74.6	11.7
2nd Hour Reading	73.9	11.7
BTU/cf, Averaged over the two hour run		1009
Calculated Heat Rate (BTU/kWh)		
2 hour Average	12354	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Audrain 8 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Audrain 8 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Audrain 8 CTG was conducted and completed on July 14, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Audrain 8	
Location	Vandalia, MO	
Date of Test	July 14, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	Lb.'s/sec
Start Reading	73.2	11.2
1st Hour Reading	73.1	11.2
2nd Hour Reading	72.9	11.2
BTU/cf, Averaged over the two hour run		1009
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11980	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE
Memo

August 10, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Fairgrounds Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Fairgrounds Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Fairgrounds CTG was conducted and completed on June 24, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Fairgrounds CTG	
Location	Jefferson City, MO	
Date of Test	June 24, 2010	
Time of Test	900 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	#2 Fuel Oil	
Test Data		
	Unit Megawatt	Lb.'s
Start Reading	1147.1	617165
1st Hour Reading	1198.8	649925
2nd Hour Reading	1250.5	682499
BTU/LB, Averaged over the two hour run		19384
Calculated Heat Rate		
1st Hour	12283 BTU/KWH	
2nd Hour	12213 BTU/KWH	
2 hour Average	12248 BTU/KWH	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Kinmundy 1 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Kinmundy 1 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Kinmundy 1 CTG was conducted and completed on August 3, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Kinmundy 1	
Location	Patoka, IL	
Date of Test	August 3, 2010	
Time of Test	900 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	KPPH
Start Reading	101.98	51.7
1st Hour Reading	100.75	50.7
2nd Hour Reading	100.05	50.7
BTU/cf, Averaged over the two hour run		1016
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11121	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Kinmundy 2 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Kinmundy 2 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Kinmundy 2 CTG was conducted and completed on August 3, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Kinmundy 2	
Location	Patoka, IL	
Date of Test	August 3, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	KPPH
Start Reading	99.3	50.8
1st Hour Reading	98.87	50.8
2nd Hour Reading	98.82	50.8
BTU/cf, Averaged over the two hour run		1015
Calculated Heat Rate (BTU/kWh)		
2 hour Average	10899	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

Ameren UE
Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Kirksville Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Kirksville Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Kirksville CTG was conducted and completed on June 23, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Kirksville	
Location	Kirksville, MO	
Date of Test	June 23, 2010	
Time of Test	1200 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Gross Megawatt Meter Reading	Gross Fuel Flow Meter Reading MCF
Start Reading	4721.5	6756
1st Hour Reading	4732.3	6943
2nd Hour Reading	4743.1	7132
BTU/cf, Averaged over the two hour run		1024
Calculated Heat Rate (BTU/kWh)		
2 hour Average	17825	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 10, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Mexico Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Mexico Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Mexico CTG was conducted and completed on June 21, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Mexico CTG	
Location	Mexico, MO	
Date of Test	June 21, 2010	
Time of Test	1000 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	#2 Fuel Oil	
Test Data		
	Unit Megawatt	Lb.'s
Start Reading	81067.2	6824
1st Hour Reading	81117.5	38339
2nd Hour Reading	81167	70396
BTU/LB, Averaged over the two hour run		19461
Calculated Heat Rate		
1st Hour	12193 BTU/KWH	
2nd Hour	12603 BTU/KWH	
2 hour Average	12398 BTU/KWH	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 10, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Moberly Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Moberly Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Moberly CTG was conducted and completed on June 22, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Moberly CTG	
Location	Moberly, MO	
Date of Test	June 22, 2010	
Time of Test	900 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	#2 Fuel Oil	
Test Data		
	Unit Megawatt	Lb.'s
Start Reading	80687	148497
1st Hour Reading	80735.4	179497
2nd Hour Reading	80783.1	210305
BTU/LB, Averaged over the two hour run		19484
Calculated Heat Rate		
1st Hour	12479 BTU/KWH	
2nd Hour	12584 BTU/KWH	
2 hour Average	12532 BTU/KWH	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE
Memo

May 17, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Moreau Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Moreau Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Moreau CTG was conducted and completed on August 28,2009. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Moreau CTG	
Location	Jefferson City, MO	
Date of Test	August 28, 2009	
Time of Test	1100 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	#2 Fuel Oil	
Test Data		
	Unit Megawatt	Lb.'s
Start Reading	86693.6	466941
1st Hour Reading	86747.3	500416
2nd Hour Reading	86801.3	533989
BTU/LB, Averaged over the two hour run		19413
Calculated Heat Rate		
1st Hour	12101 BTU/KWH	
2nd Hour	12069 BTU/KWH	
2 hour Average	12085 BTU/KWH	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

May 17, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Peno Creek Combustion Turbine Generator, Unit 4: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Peno Creek Combustion Turbine Unit #4 pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Peno Creek Unit #4 conducted and completed on April 9, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Peno Creek Energy Center		
Location	Bowling Green, MO		
Date of Test	April 9, 2010		
Time of Test	0900 hours CST		
Duration of Testing	2 hours at Steady State Load		
Fuel Type	Natural Gas		
BTU / CuFt (day of test)	1006		
Test Data			
	Unit Megawatt	Eng A, MCF	Eng B, MCF
Start Reading	165113	137850	157120
1st Hour Reading	165165	138122	157395
2nd Hour Reading	165217	138394	157667
Calculated Heat Rate			
1st Hour	10582 BTU/KWH		
2nd Hour	10524 BTU/KWH		
2 hour Average	10553 BTU/KWH		

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 1 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 1 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 1 CTG was conducted and completed on July 27, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 1	
Location	Pinckneyville, IL	
Date of Test	July 27, 2010	
Time of Test	1000 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	SCFM
Start Reading	45	7027
1st Hour Reading	45	7090
2nd Hour Reading	44.8	7055
BTU/cf, Averaged over the two hour run		1012.6
Calculated Heat Rate (BTU/kWh)		
2 hour Average	9490	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE
Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 2 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 2 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 2 CTG was conducted and completed on July 27, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 2	
Location	Pinckneyville, IL	
Date of Test	July 27, 2010	
Time of Test	1000 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	SCFM
Start Reading	44.8	7160
1st Hour Reading	44.8	7185
2nd Hour Reading	44.9	7170
BTU/cf, Averaged over the two hour run		1012.6
Calculated Heat Rate (BTU/kWh)		
2 hour Average	9708	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 3 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 3 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 3 CTG was conducted and completed on July 28, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 3	
Location	Pinckneyville, IL	
Date of Test	July 28, 2010	
Time of Test	1100 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	SCFM
Start Reading	44.1	7125
1st Hour Reading	44.3	7142
2nd Hour Reading	44.2	7136
BTU/cf, Averaged over the two hour run		1014
Calculated Heat Rate (BTU/kWh)		
2 hour Average	9778	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 4 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 4 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 4 CTG was conducted and completed on July 28, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 4	
Location	Pinckneyville, IL	
Date of Test	July 28, 2010	
Time of Test	1100 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	SCFM
Start Reading	44.2	7089
1st Hour Reading	44.2	7089
2nd Hour Reading	44.1	7109
BTU/cf, Averaged over the two hour run		1014
Calculated Heat Rate (BTU/kWh)		
2 hour Average	9751	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 5 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 5 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 5 CTG was conducted and completed on July 27, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 5	
Location	Pinckneyville, IL	
Date of Test	July 27, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	HSCFH
Start Reading	36.8	4235
1st Hour Reading	36.6	4241
2nd Hour Reading	36.5	4196
BTU/cf, Averaged over the two hour run		1011.5
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11695	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Pinckneyville 6 Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Pinckneyville 6 Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Pinckneyville 6 CTG was conducted and completed on July 27, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Pinckneyville 6	
Location	Pinckneyville, IL	
Date of Test	July 27, 2010	
Time of Test	1300 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	HSCFH
Start Reading	36.7	4210
1st Hour Reading	36.5	4232
2nd Hour Reading	36.6	4180
BTU/cf, Averaged over the two hour run		1011.5
Calculated Heat Rate (BTU/kWh)		
2 hour Average	11634	

This test was conducted and data compiled for reporting by;

John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

AmerenUE

Memo

August 9, 2010

To: Michael Taylor, MoPSC Staff

From: R. H. Deberge

RE: **Heat Rate Testing Report for Viaduct Combustion Turbine Generator: Fuel Adjustment Clause**

Listed below is the results of Heat Rate Testing for the Viaduct Combustion Turbine Generator pursuant to the provisions of the Fuel Adjustment Clause testing requirement as stipulated in 4 CSR 240-3.161(3)(Q) for AmerenUE Regulated Generating Units.

Testing for the Viaduct CTG was conducted and completed on August 5, 2010. Test data used for calculating the reported values below are on file with the Regulated CTG Department.

Unit	Viaduct	
Location	Cape Girardeau, MO	
Date of Test	August 5, 2010	
Time of Test	1400 hours CST	
Duration of Testing	2 hours at Steady State Load	
Fuel Type	Natural Gas	
Test Data		
	Unit Megawatts	MCF
Start Reading	25	392.52
1st Hour Reading	25	399.87
2nd Hour Reading	25	399.31
BTU/cf, Averaged over the two hour run		1006.84
Calculated Heat Rate (BTU/kWh)		
2 hour Average	15974	

This test was conducted and data compiled for reporting by;

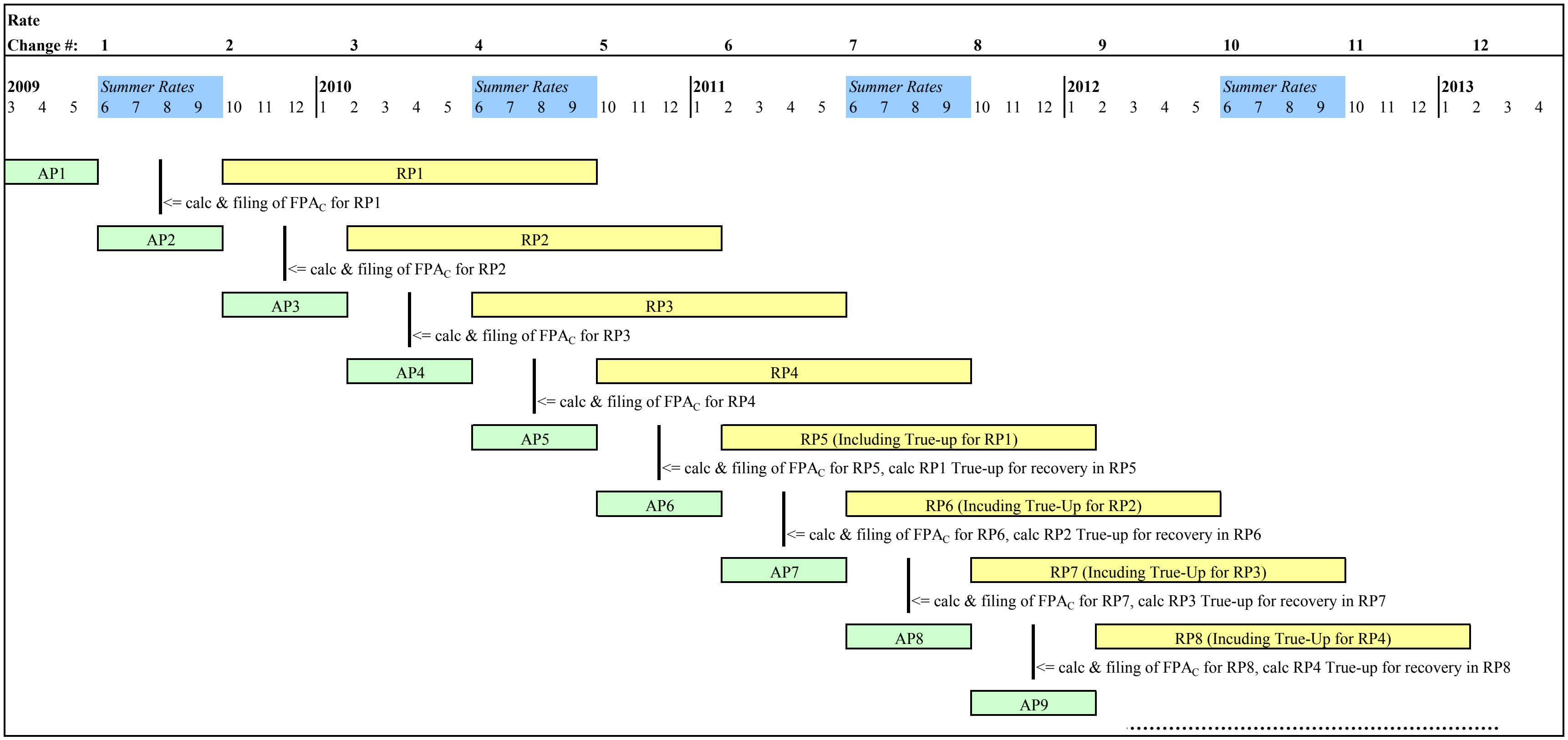
John A. Ziegler, Mechanical Engineer
Ameren Regulated Combustion Turbine Units.

Respectfully Submitted,

RHD/

cc: Osbert L. Lomax
Files

Illustration of AmerenUE's FAC with Seasonal NBFC and Rate Changes



RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 8(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Filing Date	Recovery Period (RP)
February through May	By August 1	October through September
June through September	By December 1	February through January
October through January	By April 1	June through May

Accumulation Period (AP) means the historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined.

Recovery Period (RP) means the billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FPA DETERMINATION

Ninety five percent (95%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

For the FPA filing made by each Filing Date, the FPA_C rate, applicable starting with the Recovery Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

$$FPA_{(RP)} = [[(CF+CPP-OSSR\cancel{-TS-S}-W) - (NBFC \times S_{AP})] \times 95\% + I + R - N]/S_{RP}$$

The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable starting with the following Recovery Period is calculated as:

$$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$$

where:

FPA_C = Fuel and Purchased Power Adjustment rate applicable starting with the Recovery Period following the applicable Filing Date.

FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.

$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.

$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.

CF = Fuel costs incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation, associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel or hydroelectric plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, applicable taxes, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, ~~costs and revenues for~~ ~~SO_2~~ ~~and~~ ~~NO_x~~ ~~emission allowances,~~ railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs (for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), hedging costs associated with SO2 and fuel oil

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(iii) costs and revenues for SO_2 and NO_x emission allowances;

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

CPP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance ~~(other than relating to the Taum Sauk Plant)~~ to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums ~~(other than those relating to the Taum Sauk Plant)~~ from the level reflected in base rates shall increase or decrease purchased power costs. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries ~~(other than those relating to the Taum Sauk Plant)~~ qualifying as assets under Generally Accepted Accounting Principles. ~~Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.~~

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), ~~excluding Missouri retail sales and long-term full and partial requirements sales to Missouri municipalities,~~ that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2010-0036 an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month
- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month
- All Off-System Sales revenues derived from all kWh of energy sold off-system due to the entire reduction shall be excluded from OSSR.

~~TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is $26.8 million annually , one third of which (i.e., $8.93 million) will be applied to each Accumulation Period.~~

~~S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.~~

W = $300,000 per month for the months, July 1, 2010 through, June 30, 2011. This factor "W" expires on June 30, 2011.

N = The positive amount by which, over the course of the Accumulation Period, (a) revenues derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b) the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2010-0036.

I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for ~~Taum Sauk, factor "S", and~~ factor "W") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

balances created through operation of this FAC, as determined in the true-up filings provided for herein (a portion of factor R, below). Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the FAC true-up adjustments, and modifications due to adjustments ordered by the Commission ~~(other than the adjustment for Taum Sauk as already reflected in the TS factor)~~, as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.

S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level, plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value ~~(and reflecting an adjustment for Taum Sauk, consistent with the term TS)~~ for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less an adjustment~~s~~ (consistent with the term~~s "S" and~~ "W"), expressed in cents per kWh, at the generation level, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is ~~1.236~~1.312 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is ~~1.044~~1.275 cents per kWh.

To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0789
Primary Voltage Service	1.0459
Large Transmission Voltage Service	1.0124

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

TRUE-UP OF FAC

After completion of each Recovery Period, the Company will make a true-up filing in conjunction with an adjustment to its FAC, where applicable. The true-up filings shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period. Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the Recovery Period.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Missouri Public Service Commission order implementing or continuing this Fuel and Purchased Power Adjustment Clause. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this Fuel and Purchased Power Adjustment Clause, or any period for which charges hereunder must be fully refunded. In the event a court determines that this Fuel and Purchased Power Adjustment Clause is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this Fuel and Purchased Power Adjustment Clause to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause shall occur no less frequently than every eighteen months, and any such costs which are determined by the Missouri Public Service Commission to have been imprudently incurred shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.