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Stephanie L. Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

November 10, 2008

Dear Ms. Stumbo:

This letter is in response to the October 29, 2008 letter sent to you by counsel for the Henderson Utility Commission ("Henderson"), which letter and attached documents purported to support Henderson's claims concerning the condition of Henderson Station Two. As I explain herein and as the attachments hereto show, Henderson's claims concerning the condition of Station Two are poorly supported, highly inaccurate, and are refuted by its actual performance. Henderson's own actions suggest limited concern about the condition of Station Two as it has delayed the budgeting of certain maintenance projects WKE has proposed over several years.

I address the points in Henderson's letter and exhibits in the order presented, beginning with the four Exothermic Engineering reports.

A. There Is No Credible Evidence of Damage Resulting from the Long-Term Firing of Petroleum Coke at Station Two.

The Exothermic Engineering report upon which Henderson relies in claiming there is damage to Station Two resulting from the firing of a mixture of coal and petroleum coke (also referred to as pet coke) is seriously flawed and cannot be taken to be credible evidence to support any damage claim. A credible unit condition assessment based on accepted sound engineering practices requires serious quantitative study and testing of the physical condition of system components, including non-destructive testing, tube sampling, and other life assessment techniques. The Exothermic report employed no such careful and time-consuming study; rather, as Henderson described it, the Exothermic "study" involved its engineer, Bill Smith, doing only <u>one</u> day of "visual external on-line inspection," later doing "some internal inspections," and a review of Stanley Consultants' Reports concerning Station Two from 2001 through 2006 (the Stanley reports are themselves unreliable, as

I discuss below). In other words, Mr. Smith walked around Station Two for a few days and read some old and faulty reports. This is not a sound method for an objective and meaningful unit condition assessment; indeed, the Exothermic report describes its conclusions as "qualitative," which is fitting for a study that did not involve doing the kind of rigorous work required to provide objective, quantitative data.[1] Consequently, the Exothermic Engineering report on this issue is of no probative value in answering the questions regarding the impact of burning a mixture of pet coke and coal.

The following examples of inaccuracies in the Exothermic report illustrate its unreliability:

- The report states that Station Two's mill lift liners are "extremely worn," and that such pet coke can cause such accelerated wear of fuel pulverizing and transport equipment because it is difficult to grind and more coarse than coal post-grinding.[2] In particular, the report asserts that most coals have a Hardgrove Grindability Index ("HGI") of 45 to 60, whereas pet coke typically has a 35 HGI (lower HGI indicates less grindability).[3] In fact, though, the pet coke WKE burned at Station Two had an average HGI of 48 to 57 – the same as the coal – making it less likely that pet coke grinding is disproportionately responsible for any wear.[4]

- The report further asserts that mill liners usually last 10 to 15 years;[5] however, mill liner life is a function of throughput of fuel (i.e., tons ground), not simply a number of years. Station Two's H-1 mill liners were replaced in 1981, 1986, 1996, 2005, and its H-2 liners were replaced in 1989, 1997 and 2004. (No history was available prior to 1989 on H-2.) This shows an average mill liner life of nearly eight years at Station Two. The fact that the H-1 liners lasted from 1986 to 1996 is most likely due to a lower unit capacity factor during that time frame (50% to 60%), which would require the grinding of less fuel.

[1] *See* Exothermic Engineering Pet Coke Report at 4.
[2] *Id.* at 4, 6.
[3] *Id.* at 6.
[4] Attachment 1 contains independent lab test reports showing HGI and other characteristics of the pet coke fired at Station Two during 2004-2005, when WKE fired the highest percentage of pet coke.
[5] Exothermic Engineering Pet Coke Report at 15

- The report then erroneously claims there is an accelerated rust environment in the entire facility due to the high sulfur dioxide (SO2) of pet coke.[6] This seems unlikely given that the design parameters for Station Two call for fuel with an SO2 content of 4 to 6 lbs./mmbtu, and the pet coke blended fuel fired at Station Two during 2004 and 2005 (when the percentage of pet coke was highest) was within these design specifications: 5.64 lbs/mmbtu (2004) and 5.4 lbs/mmbtu (2005).

- The Exothermic report further claims that pet coke has contaminated and damaged Station Two's Selective Catalytic Reduction ("SCR") catalyst.[7] The facts of the catalyst's performance refute this assertion, though. The Station Two catalyst has a designed life of 16,000 hours. Currently the catalyst has over 18,000 hours of service and the 2007 catalyst sample reports from both E.ON Engineering and Cormetech (the catalyst manufacturer) state that the catalyst should last approximately 28,000 to 30,000 hours.[8]

- The report states the Station Two mill ball charge is probably incorrectly classified; however, the H-1 mill balls were classified during the fall 2007 outage according to the manufacturer's recommendation.

- The report states that pet coke is responsible for boiler tube erosion, slagging, and fouling in the superheater. In fact, though, these conditions result not from firing pet coke, but rather result from Station Two's low NOx burners installed in 1996. Indeed, the author of the Exothermic Engineering report, Mr. Smith, while working as a Service Engineer for Burns & McDonnell in 1997, identified these same performance issues as problems related to the poor design of low NOx burners.[9]

B. Station Two's H-1 boiler is in better condition today than when WKE took over operations in 1998.

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[6] *Id* at 4

[7] *Id* at 4

[8] Attachment 2 contains the E.ON Engineering and Cormetech catalyst reports.

[9] *See* Attachment 3, "Draft Report, Big Rivers Electric Corporation, Review of D.B. Riley CCV NOx Burner Performance at HMP&L Station Two Unit 2," at 2, 5-7 (fax cover sheet indicates Bill Smith sent the report)

As Henderson noted in its letter, on January 27, 2007, Station Two's H-1 boiler underwent a "dry fire" event, after which WKE returned the unit to unrestricted operation; however, evidence in the Exothermic report and from WKE's own independent metallurgical analysis indicates there is no need for restricted operation, boiler tube repair, or other repairs beyond what WKE has already performed. According to its report, Exothermic Engineering removed eleven boiler tube samples from the H-1 furnace for metallurgical analysis.[10] Concerning that analysis, the report stated: "The visual and dimensional analyses did not indicate any cause for concern with the tubes received. Metallurgical analysis of the tube samples did not reveal any concerns with the microstructure. The microstructure of each sample is considered normal for the time in service. There was no evidence of creep damage identified in any of the tube samples."[11] WKE's own previous metallurgical analysis of fourteen boiler tube samples showed that the thermal incident resulted in no significant loss of expected life of the boiler tubes.[12] Indeed, Exothermic's outside metallurgical consultant, MacDonald Inspection Services ("MacDonald"), did not recommend replacing any boiler tubes at this time.[13]

MacDonald did have a handful of recommendations,[14] which are stated below with WKE's responses:

1. Tube sampling should continue, on a regular basis, as part of an ongoing inspection program for the subject boiler.

   Response: WKE already has a boiler condition assessment program, which includes routine tube sampling during each scheduled outage along with waterwall mapping and header inspections.

2. The water treatment and or conditioning program should be reviewed to ensure that proper guidelines are being met for the boiler design conditions.

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[10] Henderson Municipal Power & Light Station Two, Boiler H1, Thermal Incident Assessment Report & Repair Estimate at 4-5 (March 27, 2008)

[11] *Id* at Appx. II p. 5.

[12] *See* Attachment 4, "Unit 1 South, East and West Waterwalls Condition Assessment," by David N. French Metallurgists, at 1 (Feb. 8, 2007) ("There was no evidence of metallurgical degradation of the sample waterwall tubes resulting from the coolant disruption.").

[13] *See* Henderson Municipal Power & Light Station Two, Boiler H1, Thermal Incident Assessment Report & Repair Estimate at Appx. II p. 5-6 (March 27, 2008)

[14] *Id* at 5

Response: WKE monitors boiler water chemistry closely and a quality assurance program is in place to monitor the accuracy of the lab department.

3. If the water treatment program and pre-boiler circuitry is not adjusted, strong consideration should be given to chemically cleaning the boiler, within 3-5 years time to remove the excessive waterside deposits.

   Response: Tube sampling is conducted during each outage (every two years) to determine deposit density and chemical cleaning is based on the results of the tube samples.

4. Based on results of future tube sampling in the radiant superheater outlet section, large areas of tube replacement should be scheduled in the next 5-7 years.

   Response: It is premature to forecast when to replace some or all such tubes, which should be replaced in accord with the conditions revealed over time by the testing described above.

In addition to the above recommendations from MacDonald, Exothermic made several other suggestions for repairs, all of which WKE has performed with the exception of replacing the H-1 water walls, which Exothermic recommended because there was some bowing of those walls due to the thermal event. WKE does not believe such a repair is necessary. The H-1 unit operated with similarly warped water walls from 1984 until WKE replaced the water walls – at its sole expense – in 2005. Previously, a low water event in 1984 had similarly distorted the walls, leaving them warped when WKE began operating Station Two in 1998.[15] Thus, today the water walls are warped as they were after the 1984 event, but unlike the case when WKE assumed operation of Station Two, the H-1 water wall tubing is relatively new and in much better condition than in 1998. Moreover, water wall deformation is not uncommon for 30 year-old coal fired units, and is simply cosmetic; indeed, H-1 operated from 1984 to 2004 with a similarly warped water wall with little, if any, difficulty resulting from it.

[15] Attachment 5 is a Riley-Stoker inspection report that resulted from the 1984 low water event

C. **Because the Visual Condition Assessment Report of Station Two and the Visual Condition Assessment Repairs Cost Estimate are based on only a set of photographs, they are unreliable and have proven greatly to overstate costs based upon the cost of improvements WKE has made to Station Two.**

HMPL contracted with Exothermic in fall 2007 to conduct a visual inspection of Station Two, which resulted in over 2300 photographs of supposedly problematic conditions at Station Two, which Exothermic compiled into its Visual Condition Assessment Report. Before addressing the serious flaws in the report itself, it should be noted that Station Two's units are outdoor units that by design have been exposed to the elements for over thirty years. Moreover, the units have positive-pressure furnaces and ball mills, meaning that any small leaks or cracks will tend to look much worse than they actually are due to the positive pressure forcing dust and other particulates out of any such cracks or leaks. For these reasons, Station Two by design cannot be over time the pristine showplace one might more reasonably expect from an indoor and negative-pressure facility, and will cause a surface-level, merely photographic survey of the facility to give a more grave assessment than is accurate or appropriate.

Turning to the serious methodological flaws in the Exothermic report, as I noted above, a visual condition assessment is not an empirical technical condition assessment. Exothermic conducted no testing or instrumented measurement. Neither did Exothermic interview anyone at Station Two, nor did it ask for or review any third-party inspection reports or any operating data. Instead of doing the hard and time-consuming work required to produce a meaningful report, Exothermic personnel walked around Station Two taking photographs, as the Exothermic report itself states:

> The assessment was conducted as a visual condition assessment as opposed to a technical condition assessment. There was no testing or instrumented measurement conducted.
>
> ...
>
> This condition assessment is a Visual Condition Assessment; not a Technical Condition Assessment. A Technical Condition Assessment would include nondestructive testing (NDT) and

> rotating equipment remaining life studies to accurately determine the life remaining in each major piece of plant equipment.
>
> This Visual Condition Assessment includes no NDT and no ancillary remaining life studies. Instead, this assessment is based solely upon a visual plant inspection as documented via 2,364 photographs.[16]

Rather than relying on merely visual inspections, typical due diligence and condition assessments include interviews of production and maintenance department personnel, as well as reviews of forced outage reports, scheduled outage reports, plant maintenance programs, and third-party reports from turbine generator overhauls and transformer and switchgear maintenance programs. Because the Exothermic report is the product of no such rigorous empirical study, it is largely a collection of subjective opinion and is of no probative value for understanding the true performance characteristics and long-term prospects of Station Two.

Building on its flawed approach, Exothermic sent its myriad photographs to a third party, Associated Mechanical, Inc. ("AMI") to determine the cost estimate to address the 2109 issues Exothermic claimed to have discovered – the great majority of which are minor cosmetic or housekeeping issues – resulting in the Exothermic Visual Condition Assessment Repairs Cost Estimate. AMI looked at each Exothermic photograph and provided a cost estimate to remedy each supposed problem, which, apparently without any supplemental technical specifications or site inspections, is a difficult and inaccurate way to estimate repair costs. A few examples of issues WKE has addressed illustrate the deep infirmity of Exothermic and AMI's approach:

- Figure # 22 shows the H-1 boiler penthouse roof lagging and insulation. The cost estimate table in this report includes this repair twice, once for $72,422 and again for $55,422. WKE replaced the same kind of roof on the H-2 unit for less than $40,000.

- Figure # 27 shows the drum level transmitter pit covered in ash. The actual pit has a volume of only 18 cubic feet, yet the report lists vacuuming cost twice, once for $9,404 and again for $8,904. In fact, it

[16] Exothermic Engineering Visual Condition Assessment Report at 3, 5.

should be substantially less expensive than those costs, taking one man less than an hour to vacuum out the ash.

- Figure # 428 shows that H-2's lagging is loose and needs to be replaced at the corner of the boiler on the seventh floor. The cost estimate included in the report is $450,000. WKE replaced the lagging and insulation for $22,487.

- Figure # 46 shows that H-1's sootblower seal air box is leaking and needs to be replaced. The cost estimate included in the report is $119,037. It is planned to repair this item during the H-1 Spring 2009 outage. The material and labor to replace the seal air box is $4,000. The labor and material to replace the entire sootblower is only $40,000.

This handful of examples shows how, due to its superficial and flawed approach, the Exothermic/AMI Repairs Cost Estimate for Station Two can dramatically overstate the cost to remedy some, if not most, of the issues it identifies. Indeed, WKE has already addressed 738 of the 2109 mostly housekeeping or cosmetic items identified by Exothermic at a cost of less than $600,000, notwithstanding that Exothermic/AMI estimated the cost to repair the same items to be $3,163,840. Of the items WKE has addressed, a number were already on WKE's maintenance log to be performed during the next unit outage; the remainder WKE addressed not because they agreed with the Exothermic report's analysis, but rather to be cooperative with Henderson.

Exothermic/AMI's cost estimates are also overstated by assuming that when a problem is found with one piece of equipment, a complete repair or replacement of every such item in the plant must be necessary. Their cost estimate compounds the problem by neglecting to take into account that many such repairs or replacements are already in WKE's operations and maintenance budget, so additional budgeting is double-counting. For example, Exothermic/AMI used a bid for repair of major motors during the H-1 outage and determined a cost per motor. Exothermic/AMI then multiplied this price times the number of all major motors in the plant and included the cost to repair every major motor in this report. In fact, though, WKE performs major motor inspections and repairs on a scheduled two- to six-year interval per the plant's preventive maintenance program; the repair cycle times depend on the environments in which the motors operate. Moreover, the cost of the inspections and repairs are already in the normal O&M budgets previously listed in the Exothermic/AMI report. This example shows both of the problems with Exothermic/AMI's approach to these kinds of cost estimates: (1) there is no need to repair or replace each piece of a particular kind of equipment at the same time; and 2) by ignoring already-budgeted-for amounts to conduct such repairs and replacements, the report effectively double-counts such costs.

In summary, the Exothermic/AMI assessment was poorly considered and prepared, resulted in significantly overstated cost estimates, and identified mostly minor cosmetic or housekeeping items. Like the visual inspection of damage for pet coke firing report, this Exothermic report is flawed and unreliable.

D. The Stanley Consultants, Inc. Annual Condition Assessments upon which the Exothermic Engineering reports rely are themselves unreliable, further eroding the credibility of the Exothermic Engineering reports.

Henderson notes that the Exothermic reports relied on visual inspections of Station Two and on the Stanley Consultants, Inc. Annual Condition Assessments for calendar years 2001-2006.[17] (Curiously, HMPL provided the Commission the Stanley reports only through 2005.) Henderson goes on to note that the 2003 and 2005 Stanley reports indicate that the Station Two units are not being properly maintained and that WKE's operation of the units is compromising the expected life of the plant.[18]

The operating facts tell a different story. By several objective measures, Station Two has performed better under WKE's control than it did before, showing the Stanley reports to be unreliable. For example, the average capacity factor during the WKE era has increased from the previous 15 years.

	Average Capacity Factor 1982 – 1997 Pre WKE	**Average Capacity Factor 1998 - 2007**
H-1	72%	78.1%
H-2	67.1%	74.69%

[17] Case No. 2007-00455, Letter from John N. Hughes, counsel for Henderson, to Stephanie Stumbo, Executive Director of the Kentucky Public Service Commission, dated October 29, 2008, at 3.
[18] *Id.*

The average annual generation from the Station Two units has also increased under WKE. The average annual generation pre-WKE was 2,060,080 MWh compared to 2,282,309 MWh while WKE has operated the plant.

The Equivalent Forced Outage Rate ("EFOR") has continued to improve since 2002 and the three year average EFOR from 2005 through 2007 is in the top quartile when compared to units of this size and vintage. The Stone & Webster report dated March 24, 2008 (discussed further below) confirms this statement. Per the Stone & Webster report dated March 24, 2008, the Industry Average EFOR per the North American Electric Reliability Council (NERC) data is 6.03%.[19] The Station Two units achieved an average EFOR of less than 4% over the three year period from 2005 through 2007.[20]

Also, the Equivalent Availability Factor ("EAF") has continued to improve since 2002 and the three year average EAF from 2005 through 2007 has been greater than 87% compared to the NERC Industry Average of 85.7%.

WKE could not have achieved these performance improvements if the Station Two units were in the condition implied in the Stanley and Exothermic reports. Moreover, Big Rivers Electric Corporation ("BREC") has stated it will not close the transaction at issue in this proceeding unless all the generating units are "in good condition and state of repair,"[21] giving assurance that Station Two cannot be in the state depicted by the Stanley and Exothermic reports.

E. The Stone & Webster Management Consultants, Inc. Report of March 17, 2008, shows that Station Two's performance has improved and that Big Rivers has properly budgeted for its future needs.

Henderson further states in its letter that the Stone & Webster Management Consultants, Inc. Report of March 17, 2008, confirms the City of

[19] Case No. 2007-00455, Supplemental Response of Alcan Primary Products Corp. and Century Aluminum of Kentucky to Attorney General's Supplemental Request for Information, "Technical Assessment of Reid Station, Henderson Station Two, Green Station, K.C. Coleman Station, D.B. Wilson Station" by Stone & Webster Management Consultants, Inc. ("Stone & Webster report") at 52 (March 17, 2008).

[20] Attachment 6 contains spreadsheets from Sebree Station Energy Reports showing EFOR for units H-1 and H-2 for 2005-2007.

[21] Big Rivers' Supplemental Response to Item 88 of the Attorney General's Supplemental Request for Information at 4 (Sept. 19, 2008).

Henderson's concerns with respect to the condition of the Station Two units; however, as shown in the previous section, the Stone & Webster report actually confirms Station Two's recent above-average EFOR performance. Moreover, the Big Rivers work plan includes $1.44 million per year for major operation and maintenance and capital expenditures for H-1. Stone & Webster projects H-1 will need approximately $1.38 million per year in this classification, which is $60,000 less than already is in the Big Rivers plan for H-1.

The same is true for H-2. The Big Rivers work plan includes $1.53 million per year in the classification of major operation and maintenance and capital expenditures for H-2. Stone & Webster projects H-2 will need approximately $1.38 million per year in this classification, which is $150,000 less than already is in the Big Rivers plan for H-2.

The Big Rivers work plan for Station Two also includes most of the other items Stone & Webster suggest; indeed, some have already been completed. For example:

- New air heater rotors were installed in H-1 in 2003 and H-2 in 2004
- Both units are currently being retrofitted with new Distributive Control Systems
- The BREC work plan includes Structural Life Assessment for H-1 in 2009 and H-2 in 2010
- The re-heater was replaced on H-2 in 2008
- New burners for the boilers are in the BREC capital plan for H-1 in 2011 and H-2 in 2012
- Turbine blade replacements in later years are included in the baseline capital budget.

Therefore, far from confirming that Station Two is in sub-par shape, the Stone & Webster report shows that Station Two is performing well to date, and that there is adequate provision made in the Big Rivers work plan for future repair and replacement work needed on H-1 and H-2. Such work is typical for units of this age and type.

F. Repair costs in Tab 7 of the information attached to Henderson's letter contain projects at inflated costs and some unnecessary projects.

Attached as Tab 7 (entitled, "Exhibit C") to Henderson's letter is a schedule purporting to support the claim that Station Two requires $92,000,000 of repairs; however, of that amount, almost $47 million is actually planned operation and maintenance expense that is already contained in the BREC work plan for Station Two (see section A of Exhibit C). The items listed in Section B of Exhibit C, which total $18.7 million, were removed from the initial BREC work plan after further research showed them not to be necessary; indeed, HMPL management stated at the time they were removed, "[T]here is no way we can approve or fund this plan."[22] It is noteworthy that some of the cost estimates in the Exothermic report do not match with those submitted in Exhibit C, such as boiler painting. For example, Exhibit C includes $6,000,000 total for boiler painting ($3,000,000 per unit), whereas the Exothermic report includes $3,500,000 total for boiler painting.[23]

In section C of Exhibit C are two items, the "H1 and H2 Exothermic Engineering Repair List" ($17,134,000) and the "H1 Exothermic Engineering Dry Fire Fire [sic] Assessment Repair" ($3,484,344). Concerning the first item, WKE has shown in section C of this letter that the cost estimates associated with the 2109 problems the Exothermic report claimed to find at Station Two have been grossly exaggerated; WKE has remedied 738 of the claimed problems for less than $600,000, whereas Exothermic/AMI estimated the cost for the same repairs to be $3,163,840. Given that there is already $5,729,840 set aside in the BREC Station Two work plan for repairs covered in the Exothermic report, there should be more than enough to complete the remaining repairs, if such are in fact necessary. Concerning the thermal incident repairs, as stated at length in section B of this letter, no repairs are needed at Station Two as a result of the 2007 dry fire incident.

Finally, with respect to section D of Exhibit C, "Dredging Station Two Ash Pond," more than the amount set out in Exhibit C is already part of the BREC Station Two work plan, albeit for ash pond dredging in 2015.

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[22] Verbal statement of Wayne Thompson upon BREC's presentation of first draft Station Two work plan to HMPL and WKE

[23] Case No. 2007-00455, Letter from John N Hughes, counsel for Henderson, to Stephanie Stumbo, Executive Director of the Kentucky Public Service Commission, dated October 29, 2008, at Exh. C

Attachment 7 hereto is a schedule showing the various Exhibit C amounts as compared to the amounts set aside in the BREC Station Two work plan, along with annotations for entries where relevant.

G. The City of Henderson bears some responsibility if certain repairs to Station Two have not been timely made.

The last full paragraph of Henderson's letter states, "Henderson did not eliminate any project during this 5 year period that is currently listed in Tab 7 Exhibit C of Henderson's proposed Draft Station Two Unwind Termination and Release Agreement." In fact, HMPL began deferring requested repair items during the 2005-2006 fiscal budget period. One such item is the deferral of sootblower replacements which is specifically identified and included in Section C item XXI of Exhibit C. In Tab 8 to Henderson's letter it can be seen that HMPL finally eliminated these sootblowers from the 2008-2009 fiscal budget. Other items deferred include cooling tower repairs, specifically the distribution deck.[24] These items were deferred by HMPL when at their request the H-2 outage was deferred from the 2007-2008 fiscal year to the 2008-2009 fiscal year.[25] Deferring maintenance items has the same impact as eliminating them, as the maintenance is not performed when it is needed.

H. Conclusion

In conclusion, there are significant reasons to doubt the credibility of the evidence the City of Henderson has provided to support its claims with respect to Station Two. First, the four Exothermic Engineering reports Henderson has provided suffer from poor preparation and analysis and are not a serious or objective facility condition assessment of Station Two based on empirical data. Second, the cost estimates for repair work suggested in the Exothermic reports are severely exaggerated, and WKE has already remedied over a third of the 2109 problems Exothermic claims to have identified – all at a cost less than one fifth of what Exothermic estimated the repairs should cost. Third, Stanley Consultants, Inc. Annual Condition Assessments upon which the Exothermic reports rely are themselves inaccurate, claiming that Station Two is not being properly maintained and that WKE is compromising the life of the units notwithstanding that capacity factor, availability, and EFOR performance measures all show that Station Two is now performing as well as or better than

[24] *See* Tab 8 of Hughes Letter, "Henderson Station Two 2007-2008 Budget."

[25] Attachment 8 is an e-mail from Wayne Thompson of HMPL to WKE personnel requesting the outage delay ("I would like for you or your staff to look at the possib[ility] of the Spring 2008 H2 Planned Outage being moved to the Fall of 2008 to help with this year['s] budget.")

it did prior to 1998 when WKE took over operations. The Stone & Webster Management Consultants, Inc. Report of March 17, 2008, further bolsters this conclusion with positive performance data and evidence that the current BREC work plan for Station Two contains budget items to account for proper repair and maintenance of the plant in the future. Finally, WKE has shown that Henderson has exaggerated the amount of repairs that need to be done to Station Two in the future, and ignores its role in delaying repairs WKE has suggested in the past few years.

For all of these reasons, I respectfully suggest that the Commission should give little, if any, probative weight to the information supplied in Henderson's letter to Ms. Stumbo on October 29, 2008.

Sincerely,

Ralph Bowling

Ralph Bowling

ATTACHMENT 1

PET COKE HGI ANALYSES 2004 – 2005

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389 Exxon Mobile
September 2004

Kind of sample reported to us	Pet Coke
Sample taken at	------
Sample taken by	-----
Date sampled	------
Date received	November 5, 2004

Analysis Report No. 63-60369

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.53	xxxxx
% Ash	0.32	0.34
% Volatile	11.02	11.79
% Fixed Carbon	82.13	87.87
	100.00	100.00
Btu/lb	14164	15153
% Sulfur	5.26	5.63
MAF Btu		15205
Alk. as Sodium Oxide	0.01	0.01

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.53	xxxxx
% Carbon	81.97	87.70
% Hydrogen	3.28	3.51
% Nitrogen	1.35	1.44
% Sulfur	5.26	5.63
% Ash	0.32	0.34
% Oxygen(diff)	1.29	1.38
	100.00	100.00
% Chlorine	0.02	0.02

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2700+	2010
Softening (ST)	2700+	2095
Hemispherical (HT)	2700+	2240
Fluid (FT)	2700+	2350

GRINDABILITY INDEX = 51 at 0.35 % Moisture

MEMBER ACIL

Respectfully submitted.
SGS NORTH AMERICA INC.

Henderson Laboratory

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P.O. Box 752, Henderson, KY 42419 t (270) 827-11F7 f (270) 826-0719 www.sgs.com
Member of the SGS Group

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
September 2004

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis Report No. 63-60369

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	5.24	5.61
% Sulfur	5.26	5.63

MEMBER ACIL

Respectfully submitted.
SGS NORTH AMERICA INC

Henderson Laboratory

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
September 2004

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis report no. 63-60369

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	16.14
Aluminum oxide	7.59
Titanium dioxide	1.27
Iron oxide	8.42
Calcium oxide	5.21
Magnesium oxide	1.22
Potassium oxide	0.50
Sodium oxide	3.71
Sulfur trioxide	6.80
Phosphorus pentoxide	0.08
Strontium oxide	0.03
Barium oxide	0.06
Manganese oxide	0.16
Nickel oxide	10.82
Vanadium oxide	36.28
Undetermined	1.71
	100.00

Silica Value = 52.08
Base:Acid Ratio = 0.76
T_{250} **Temperature** = < 2000

Type of Ash = BITUMINOUS
Fouling Index = 2.82
Slagging Index = 4.28

MEMBER ACIL

Respectfully submitted
SGS NORTH AMERICA INC.

Henderson Laboratory

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
September 2004

Kind of sample reported to us	Pet Coke
Sample taken at	------
Sample taken by	-----
Date sampled	------
Date received	November 5, 2004

Analysis Report No. 63-60369

Arsenic	2 ug/g
Vanadium	813 ug/g

MEMBER ACIL

Respectfully submitted.
SGS NORTH AMERICA INC

Henderson Laboratory

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389 Mobile
October 2004

Kind of sample reported to us: Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis Report No. 63-60370

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	7.76	xxxxx
% Ash	0.34	0.37
% Volatile	10.45	11.33
% Fixed Carbon	81.45	88.30
	100.00	100.00
Btu/lb	13988	15165
% Sulfur	5.29	5.74
MAF Btu		15221
Alk. as Sodium Oxide	0.01	0.01

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	7.76	xxxxx
% Carbon	80.38	87.14
% Hydrogen	3.15	3.42
% Nitrogen	1.35	1.46
% Sulfur	5.29	5.74
% Ash	0.34	0.37
% Oxygen(diff)	1.73	1.87
	100.00	100.00
% Chlorine	0.02	0.02

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2700+	2020
Softening (ST)	2700+	2110
Hemispherical (HT)	2700+	2260
Fluid (FT)	2700+	2390

GRINDABILITY INDEX = 46 at 0.33 % Moisture

MEMBER ACIL

Respectfully submitted
SGS NORTH AMERICA INC

Henderson Laboratory

SGS North America Inc | Minerals Services Division
P.O. Box 752, Henderson, KY 42419 t (270) 827-1187 f (270) 826-0719 www.sgs.com
Member of the SGS Group

F-465

SGS

December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
October 2004

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis Report No. 63-60370

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	5.27	5.72
% Sulfur	5.29	5.74

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Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
October 2004

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis report no. 63-60370

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	12.84
Aluminum oxide	7.98
Titanium dioxide	1.25
Iron oxide	10.46
Calcium oxide	7.10
Magnesium oxide	1.35
Potassium oxide	0.52
Sodium oxide	3.60
Sulfur trioxide	6.95
Phosphorus pentoxide	0.35
Strontium oxide	0.04
Barium oxide	0.06
Manganese oxide	0.13
Nickel oxide	11.18
Vanadium oxide	35.22
Undetermined	0.97
	100.00

Silica Value = 40.44
Base:Acid Ratio = 1.04
T_{250} **Temperature =** < 2000

Type of Ash = BITUMINOUS
Fouling Index = 3.74
Slagging Index = 5.97

MEMBER ACIL

Respectfully submitted
SGS NORTH AMERICA INC

Henderson Laboratory

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December 21, 2004

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

Pet Coke Barge Composite
Henderson Plant
V/N 389
October 2004

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by -----

Date sampled ------

Date received November 5, 2004

Analysis Report No. 63-60370

Arsenic	2 ug/g
Vanadium	552 ug/g

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Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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February 15, 2005

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by

EXXON/MOBILE
December 2004
V/N 389
HENDERSON

Kind of sample reported to us Pet Coke

Sample taken at ------

Sample taken by ------

Date sampled ------

Date received January 5, 2005

Analysis Report No. 63-65746

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	11.39	xxxxx
% Ash	0.53	0.60
% Volatile	10.18	11.49
% Fixed Carbon	77.90	87.91
	100.00	100.00
Btu/lb	13435	15162
% Sulfur	5.48	6.19
MAF Btu		15254
Alk. as Sodium Oxide	0.02	0.02

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	11.39	xxxxx
% Carbon	77.09	87.00
% Hydrogen	3.35	3.78
% Nitrogen	1.36	1.53
% Sulfur	5.48	6.19
% Ash	0.53	0.60
% Oxygen(diff)	0.80	0.90
	100.00	100.00
% Chlorine	0.03	0.03

FUSION TEMPERATURE OF ASH, (ºF)

	Reducing	Oxidizing
Initial Deformation (IT)	2580	2060
Softening (ST)	2635	2100
Hemispherical (HT)	2700+	2160
Fluid (FT)	2700+	2200

GRINDABILITY INDEX = 49 at 0.25 % **Moisture**

MEMBER ACIL

Respectfully submitted,
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February 15, 2005

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by

EXXON/MOBILE
December 2004
V/N 389

Kind of sample reported to us: Pet Coke

Sample taken at: ------

Sample taken by: ------

Date sampled: ------

Date received: January 5, 2005

Analysis Report No. 63-65746

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.02	0.02
% Sulfate	0.01	0.01
% Organic(diff)	5.45	6.16
% Sulfur	5.48	6.19

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February 15, 2005

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by

EXXON/MOBILE
December 2004
V/N 389

Kind of sample reported to us	Pet Coke
Sample taken at	------
Sample taken by	------
Date sampled	------
Date received	January 5, 2005

Analysis report no. 63-65746

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	25.45
Aluminum oxide	8.32
Titanium dioxide	0.83
Iron oxide	13.95
Calcium oxide	4.23
Magnesium oxide	1.29
Potassium oxide	1.06
Sodium oxide	2.58
Sulfur trioxide	9.52
Phosphorus pentoxide	0.17
Strontium oxide	0.03
Barium oxide	0.09
Manganese oxide	0.08
Nickel oxide	4.12
Vanadium pentoxide	27.10
Undetermined	1.18
	100.00

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Member of the SGS Group

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February 15, 2005

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by

EXXON/MOBILE
December 2004
V/N 389

Kind of sample reported to us	Pet Coke
Sample taken at	------
Sample taken by	------
Date sampled	------
Date received	January 5, 2005

Analysis Report No. 63-65746

Arsenic	1 ug/g
Vanadium	987 ug/g

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

September 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	------
Date received	October 24, 2005

Analysis Report No. 63-91668

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	7.41	xxxxx
% Ash	0.29	0.31
% Volatile	9.94	10.74
% Fixed Carbon	82.36	88.95
	100.00	100.00
Btu/lb	14186	15321
% Sulfur	5.35	5.78
MAF Btu		15369
Alk. as Sodium Oxide	0.01	0.01

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	7.41	xxxxx
% Carbon	81.35	87.86
% Hydrogen	3.48	3.76
% Nitrogen	1.40	1.51
% Sulfur	5.35	5.78
% Ash	0.29	0.31
% Oxygen(diff)	0.72	0.78
	100.00	100.00
% Chlorine	0.02	0.02

FUSION TEMPERATURE OF ASH, (ºF)

	Reducing	Oxidizing
Initial Deformation (IT)	2300	2700+
Softening (ST)	2360	2700+
Hemispherical (HT)	2430	2700+
Fluid (FT)	2605	2700+

GRINDABILITY INDEX = 51 at 0.50 % Moisture

Respectfully submitted.
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January 16, 2006

WESTERN KENTUCKY ENERGY CORP
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

September 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us: Pet Coke

Sample taken at: Henderson Station

Sample taken by: Client

Date sampled: ------

Date received: October 24, 2005

Analysis Report No. 63-91668

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	5.33	5.76
% Sulfur	5.35	5.78

Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

September 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	------
Date received	October 24, 2005

Analysis report no. 63-91668

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	11.57
Aluminum oxide	5.46
Titanium dioxide	0.84
Iron oxide	11.03
Calcium oxide	8.32
Magnesium oxide	1.41
Potassium oxide	0.47
Sodium oxide	2.92
Sulfur trioxide	14.53
Phosphorus pentoxide	0.27
Strontium oxide	0.05
Barium oxide	0.09
Manganese oxide	0.11
Nickel oxide	5.78
Vanadium oxide	35.80
Undetermined	15.49
	100.00

Silica Value = 35.79
Base:Acid Ratio = 1.35

Type of Ash = BITUMINOUS

Respectfully submitted,
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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

September 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	*Henderson Station*
Sample taken by	Client
Date sampled	------
Date received	October 24, 2005

Analysis Report No. 63-91668

Arsenic	3 ug/g
Vanadium	601 ug/g

Respectfully submitted,
SGS NORTH AMERICA INC

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

November 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	November 1-30, 2005
Date received	December 7, 2005

Analysis Report No. 63-95868

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	9.06	xxxxx
% Ash	0.23	0.25
% Volatile	9.93	10.92
% Fixed Carbon	80.78	88.83
	100.00	100.00
Btu/lb	13884	15267
% Sulfur	5.45	5.99
MAF Btu		15305
Alk. as Sodium Oxide	0.01	0.01

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	9.06	xxxxx
% Carbon	79.08	86.96
% Hydrogen	3.25	3.57
% Nitrogen	1.54	1.69
% Sulfur	5.45	5.99
% Ash	0.23	0.25
% Oxygen(diff)	1.39	1.54
	100.00	100.00
% Chlorine	0.01	0.01

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2700+	2375
Softening (ST)	2700+	2440
Hemispherical (HT)	2700+	2500
Fluid (FT)	2700+	2580

GRINDABILITY INDEX = 50 at 0.80 % Moisture

Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

November 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	November 1-30, 2005
Date received	December 7, 2005

Analysis Report No. 63-95868

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	5.43	5.97
% Sulfur	5.45	5.99

Respectfully submitted,
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Henderson Laboratory

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

November 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	November 1-30, 2005
Date received	December 7, 2005

Analysis report no. 63-95868

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	5.39
Aluminum oxide	3.08
Titanium dioxide	0.15
Iron oxide	4.24
Calcium oxide	1.91
Magnesium oxide	0.42
Potassium oxide	0.25
Sodium oxide	2.47
Sulfur trioxide	3.18
Phosphorus pentoxide	0.11
Strontium oxide	0.02
Barium oxide	0.05
Manganese oxide	0.03
Nickel oxide	8.67
Vanadium oxide	68.80
Undetermined	0.25
	100.00

Silica Value = 45.07
Base:Acid Ratio = 1.08

Type of Ash = BITUMINOUS

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

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January 16, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

November 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #389

Kind of sample reported to us	Pet Coke
Sample taken at	*Henderson Station*
Sample taken by	Client
Date sampled	November 1-30, 2005
Date received	December 7, 2005

Analysis Report No. 63-95868

Arsenic	2 ug/g
Vanadium	963 ug/g

Respectfully submitted.
SGS NORTH AMERICA INC

Henderson Laboratory

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February 7, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

December 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #429

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	December 1-31, 2005
Date received	January 5, 2006

Analysis Report No. 63-98530

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.62	xxxxx
% Ash	0.15	0.16
% Volatile	8.99	9.53
% Fixed Carbon	85.24	90.31
	100.00	100.00
Btu/lb	14495	15358
% Sulfur	4.49	4.76
MAF Btu		15383
Alk. as Sodium Oxide	0.00	0.00

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.62	xxxxx
% Carbon	82.71	87.64
% Hydrogen	3.53	3.74
% Nitrogen	1.62	1.72
% Sulfur	4.49	4.76
% Ash	0.15	0.16
% Oxygen(diff)	1.88	1.98
	100.00	100.00
% Chlorine	0.01	0.01

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2400	2700+
Softening (ST)	2460	2700+
Hemispherical (HT)	2530	2700+
Fluid (FT)	2590	2700+

GRINDABILITY INDEX = 49 at 0.67 % Moisture

Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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February 7, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

December 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #429

Kind of sample reported to us: Pet Coke

Sample taken at: Henderson Station

Sample taken by: Client

Date sampled: December 1-31, 2005

Date received: January 5, 2006

Analysis Report No. 63-98530

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	4.47	4.74
% Sulfur	4.49	4.76

Respectfully submitted.
SGS NORTH AMERICA INC.

Henderson Laboratory

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February 7, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

December 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #429

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	December 1-31, 2005
Date received	January 5, 2006

Analysis report no. 63-98530

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	4 32
Aluminum oxide	2.52
Titanium dioxide	0.13
Iron oxide	3.35
Calcium oxide	2.39
Magnesium oxide	0.50
Potassium oxide	0.05
Sodium oxide	1.54
Sulfur trioxide	3.88
Phosphorus pentoxide	0.05
Strontium oxide	0.02
Barium oxide	0.05
Manganese oxide	0.02
Nickel oxide	11.62
Vanadium oxide	68.30
Undetermined	1.26
	100.00

Silica Value = 40.91
Base:Acid Ratio = 1.12

Type of Ash = BITUMINOUS

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

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February 7, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

December 2005 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #429

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	December 1-31, 2005
Date received	January 5, 2006

Analysis Report No. 63-98530

Arsenic	6 ug/g
Vanadium	1429 ug/g

Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

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March 6, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

January 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	January 1-31, 2006
Date received	February 15, 2006

Analysis Report No. 63-102115

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	9.14	xxxxx
% Ash	0.34	0.37
% Volatile	10.28	11.31
% Fixed Carbon	80.24	88.32
	100.00	100.00
Btu/lb	13860	15254
% Sulfur	5.06	5.57
MAF Btu		15311
Alk. as Sodium Oxide	0.01	0.02

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	9.14	xxxxx
% Carbon	79.10	87.06
% Hydrogen	3.39	3.73
% Nitrogen	1.49	1.64
% Sulfur	5.06	5.57
% Ash	0.34	0.37
% Oxygen(diff)	1.48	1.63
	100.00	100.00
% Chlorine	0.02	0.02

FUSION TEMPERATURE OF ASH, (ºF)

	Reducing	Oxidizing
Initial Deformation (IT)	2120	2700+
Softening (ST)	2140	2700+
Hemispherical (HT)	2180	2700+
Fluid (FT)	2220	2700+

GRINDABILITY INDEX = 54 at 0.51 % Moisture

Respectfully submitted.
SGS NORTH AMERICA INC

Henderson Laboratory

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March 6, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

January 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us Pet Coke

Sample taken at Henderson Station

Sample taken by Client

Date sampled January 1-31, 2006

Date received February 15, 2006

Analysis Report No. 63-102115

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	0.01	0.01
% Sulfate	0.01	0.01
% Organic(diff)	5.04	5.55
% Sulfur	5.06	5.57

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

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March 6, 2006

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P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

January 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us Pet Coke

Sample taken at Henderson Station

Sample taken by Client

Date sampled January 1-31, 2006

Date received February 15, 2006

Analysis Report No. 63-102115

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	21.20
Aluminum oxide	4.89
Titanium dioxide	0.85
Iron oxide	13.10
Calcium oxide	5.67
Magnesium oxide	1.19
Potassium oxide	0.53
Sodium oxide	3.76
Sulfur trioxide	14.15
Phosphorus pentoxide	0.26
Strontium oxide	0.04
Barium oxide	0.07
Manganese oxide	0.16
Undetermined	34.13
	100.00

Silica Value = 51.51
Base:Acid Ratio = 0.90
T_{250} Temperature = 2160 °F

Type of Ash = BITUMINOUS
Fouling Index = 3.38
Slagging Index = 5.01

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

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March 6, 2006

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HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

January 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us Pet Coke

Sample taken at Henderson Station

Sample taken by Client

Date sampled January 1-31, 2006

Date received February 15, 2006

Analysis Report No. 63-102115

Arsenic	2 ug/g
Vanadium	611 ug/g

Respectfully submitted,
SGS NORTH AMERICA INC

Henderson Laboratory

SGS

April 27, 2006

WESTERN KENTUCKY ENERGY CORP
P. O BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by Client

March 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us: Pet Coke

Sample taken at: Henderson Station

Sample taken by: Client

Date sampled: March 1-31, 2006

Date received: April 10, 2006

Analysis Report No. 63-107409

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	8.36	xxxxx
% Ash	0.34	0.37
% Volatile	9.96	10 87
% Fixed Carbon	81.34	88.76
	100.00	100 00
Btu/lb	13878	15144
% Sulfur	5.99	6.54
MAF Btu		15200
Alk. as Sodium Oxide	0.01	0.01

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	8.36	xxxxx
% Carbon	78.59	85.76
% Hydrogen	3.18	3.47
% Nitrogen	3.18	3.47
% Sulfur	5.99	6.54
% Ash	0 34	0.37
% Oxygen(diff)	0.36	0.39
	100 00	100.00
% Chlorine	0.02	0.02

FUSION TEMPERATURE OF ASH, (ºF)

	Reducing	Oxidizing
Initial Deformation (IT)	2340	2700+
Softening (ST)	2420	2700+
Hemispherical (HT)	2490	2700+
Fluid (FT)	2540	2700+

GRINDABILITY INDEX = 47 at 1.08 % Moisture

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

SGS

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HENDERSON KY 42419
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Client

March 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	March 1-31, 2006
Date received	April 10, 2006

Analysis Report No. 63-107409

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	7.37
Aluminum oxide	3.18
Titanium dioxide	0.20
Iron oxide	5.87
Calcium oxide	3.00
Magnesium oxide	0.33
Potassium oxide	0.04
Sodium oxide	3.37
Sulfur trioxide	7.50
Phosphorus pentoxide	0.21
Strontium oxide	0.02
Barium oxide	0.07
Manganese oxide	0.04
Undetermined	68.80
	100.00

Silica Value = 44.48
Base:Acid Ratio = 1.17
T_{250} Temperature = 2150 °F

Type of Ash = BITUMINOUS
Fouling Index = 3.94
Slagging Index = 7.65

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

SGS

April 27, 2006

WESTERN KENTUCKY ENERGY CORP.
P. O. BOX 1518
HENDERSON KY 42419
JACK JACOBS

Sample identification by
Client

March 2006 Composite
Exxon Mobile/Joliet
Henderson Station
V/N #466

Kind of sample reported to us	Pet Coke
Sample taken at	Henderson Station
Sample taken by	Client
Date sampled	March 1-31, 2006
Date received	April 10, 2006

Analysis Report No. 63-107409

Arsenic	1 ug/g
Vanadium	33 ug/g

Respectfully submitted,
SGS NORTH AMERICA INC.

Henderson Laboratory

ATTACHMENT 2

CATALYST LIFE REPORTS

CORMETECH

Western Kentucky Energy
Henderson Unit 1
For Alstom

SCR Catalyst
Pilot Performance Test Report
14,808 Operating Hours
47 Months Since First Gas-In

Submitted by

CORMETECH, INC.
Environmental Technologies
5000 International Drive
Durham, NC 27712
(919) 620-3000

Mark Schirmer
Senior Project Manager

Mark A Conger

Mark A Conger
Senior Project Engineer

Certifying Laboratory Representative:
John Gunter, Laboratory Operations Manager

February 7, 2008

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PURPOSE

This test is conducted to audit the catalytic potential of an SCR catalyst by measuring the performance of a field catalyst sample that has been in operation for a known duration. The catalytic potential is measured by laboratory scale testing of field samples removed from the SCR. Pilot tests are conducted in a controlled, laboratory environment allowing accurate comparisons of field sample catalytic potential to that of fresh catalyst. The deactivation rate is determined by comparing the change in catalytic potential versus operating hours of the sample.

Field performance, as indicated by plant-supplied measurements and observations, is also analyzed and discussed relative to the performance of the catalyst samples tested. Measured field performance in conjunction with laboratory measurements of field sample catalytic potential is used to determine actual unit scale-up factors. Utilizing actual unit scale-up factors significantly improves the accuracy of future performance predictions.

If laboratory test results are inconsistent with any of the following, further catalyst and/or field operation analysis may be recommended:

- Cormetech's experience base of comparable units
- The plant's reported field performance, if available
- The results of previous audits of the unit, if applicable
- The performance expectations for the unit

BACKGROUND

In order to achieve design performance requirements of a Selective Catalytic Reduction system for a specified timeframe (life) of the SCR catalyst, the catalyst formulation, structure, and volume are specifically designed to accommodate the system operating conditions, the predicted system scale-up factors, and a predicted rate of decrease in catalyst potential over time.

If any of the design or operating parameters above is not realized, then the actual duration that the design performance requirements can be met may deviate from the design life. The individual contribution of each parameter on actual life is described below. In actual practice, one or more of these parameters may deviate from design and either counteract or complement each other.

Performance Requirements: If the actual plant performance requirements are more stringent than the design performance requirements, actual life will be less than design life. An example of this would be a unit that was designed to achieve a certain NO_x reduction at given ammonia slip, but is actually required to achieve a higher NO_x reduction.

Operating Conditions: Flue gas flow rate, inlet NO_x levels, temperature, oxygen content, and water content impact catalytic potential. If the catalyst is at an operating condition where the potential is lower than design, actual life will be less than design life.

Scale-Up Factors: The full NOx reduction potential of the catalyst is not attained in the field due to non-ideal flow distribution, temperature distribution, ammonia to NOx molar ratio distribution, catalyst blockage, and/or flue gas bypass. Collectively, these non-ideal conditions are accounted for with 'system scale-up factors'. If the overall actual system scale-up factors are more severe than the design scale-up factors, then the potential of the SCR system to meet a given performance requirement is reduced.

Catalyst Deactivation Rate: Catalytic potential decreases over time. This catalyst deactivation rate has a direct impact on actual life. If the deactivation rate is more than design, then actual life effectively reduced. If the deactivation rate is less than design, the actual life is effectively increased.

If any or all of the first three parameters; namely, performance requirements, operating conditions, and scale-up factors, are more stringent than the initial design, then less margin for catalyst deactivation remains. Therefore, actual life will be less than design life.

At any given time and operating condition, the SCR system performance is dictated by the NO_x reduction potential of the catalyst and the system scale-up factors. These factors reduce performance from the catalytic potential to the performance achievable in the operating SCR system.

Pilot performance tests are purposefully conducted in a controlled environment, free from the scale-up factors that adversely affect SCR system performance, and at repeatable operating conditions so that changes in catalytic potential may be evaluated accurately. Catalyst deactivation can be determined by testing the field catalyst sample at the same operating conditions as the test of the fresh sample and assigning the relative change in catalytic potential to catalyst deactivation.

In conjunction with pilot test results, analysis of field SCR system performance data can confirm: the field performance requirements, the plant operating conditions, and actual system scale-up factors.

Cormetech's SCR catalyst design and testing experience enables analysis of the actual versus design values of: performance requirements, operating conditions, system scale-up, and catalyst deactivation to predict future catalyst performance.

FACILITY OPERATIONAL HISTORY

Western Kentucky Energy Henderson Unit 1 is a Pulverized Coal Unit. The SCR system consists of a single reactor. The reactor currently contains two layers of Cormetech 7.1 mm pitch catalyst. The SCR was put into operation in November 2003.

On November 2, 2004, catalyst samples were removed for testing. At the time the samples were removed, the SCR had accumulated 3,333 operating hours. The results of this previous audit are included in this report.

On October 14, 2005, catalyst samples were removed for testing. At the time the samples were removed, the SCR had accumulated 6,931 operating hours. The results of this previous audit are included in this report.

On October 20, 2006, catalyst samples were removed for testing. At the time the samples were removed, the SCR had accumulated 11,062 operating hours. The results of this previous audit are included in this report.

On October 3, 2007, one sample was removed from each layer and returned to Cormetech for laboratory testing. At the time the samples were removed, the SCR had accumulated 14,808 operating hours. This report summarizes the results of the audit.

PROCEDURE OVERVIEW

1. One catalyst sample was removed from the *field sampler in each* layer at the Western Kentucky Energy Henderson Unit 1 SCR. The samples were shipped to Cormetech's laboratory. Operating history was recorded by the *Generating Station* and forwarded to Cormetech.

2. The physical condition of the catalyst was documented by Cormetech.

3. The catalyst was loaded into a Pilot Activity Test Apparatus and then evaluated at the *design* conditions for the plant SCR. The Pilot Activity Test Procedure Standard is included in Appendix 3.

4. The results include catalyst potential expressed as K/Ko.

5. Test results were compared to design. Expectations of catalyst deactivation were determined by the time on-line, experience data of similar coal-fired facilities, and *fresh catalyst performance*.

6. An *expected catalyst life prediction* is based on the above testing and analysis.

FIELD SAMPLING AND UNIT OPERATING CONDITIONS

Field Sampling

One catalyst sample was removed from the field sampler in each layer at the Western Kentucky Energy Henderson Unit 1 SCR and sent to Cormetech's Laboratory for evaluation.

Operating Status:

Field records supplied by Western Kentucky Energy are summarized in the table below.

First Gas-In Date with Catalyst Installed	November 2003
Sample Removal Date	October 3, 2007
Total Operating Hours On Catalyst Sample	14,808
Primary Fuel Fired	Blend

LABORATORY PERFORMANCE TEST CONDITIONS

A pilot test was conducted on the sample received using the conditions below. These conditions reflect the *original* pilot test condition for which there is fresh catalyst test data available for direct comparison.

Temperature	356 °C (673 °F)
Area Velocity	10.0 Nm/h
O_2, vol. %, dry	3.10%
Inlet NO_x ppmvd	299.3 @ 3.10% O_2 (301.0 @ 3% O_2)

RESULTS

Physical Inspection

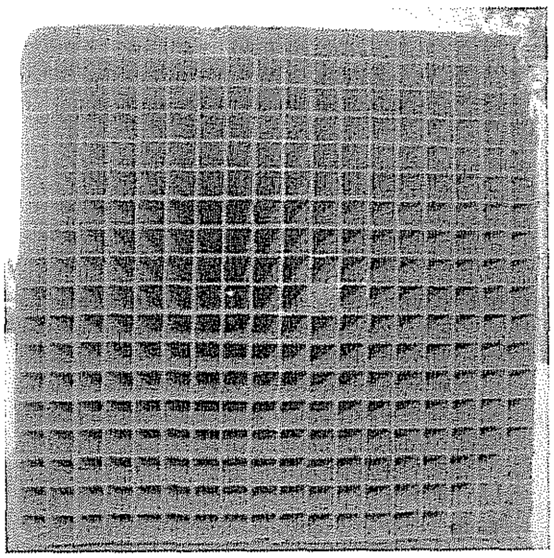
The figures on the following pages show photographs of the flow entrance face and the flow exit face of the elements as they arrived at Cormetech.

The samples received were 18 cells x 18 cells and exhibit plugged cells in two opposite corners. This is a result of the sample tray design and does not affect the results of the testing. The testing of the elements was not adversely impacted by the element condition.

ID #: 0508-2960-0249
Layer 1

<table>
<tr><td>

Flow Entrance Face



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Physical Inspection Observations:

Sleeve Marking: H-1 #58 top layer 10-3-07 Western Kentucky Energy HMPL Unit-1

Box Marking: Henderson unit-1 Box: H-1 Top layer #58 10-3-07

Cell Count: 18 x 18 shaved

Plugged Cells

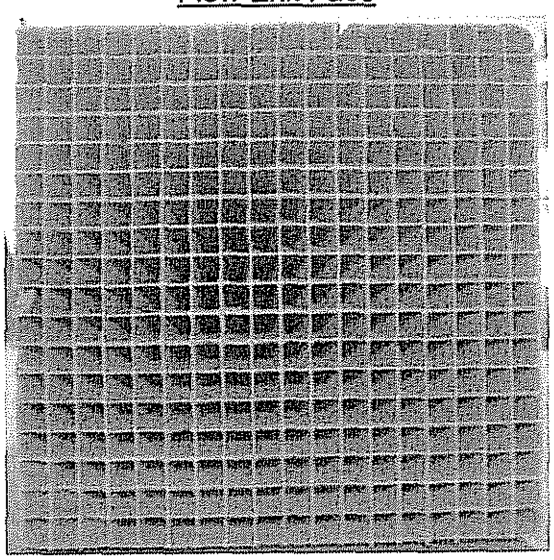
Initial: 14 Final: 0

Length: 1206 mm

Inspection Notes: Element in good condition

</td></tr>
<tr><td>

Flow Exit Face



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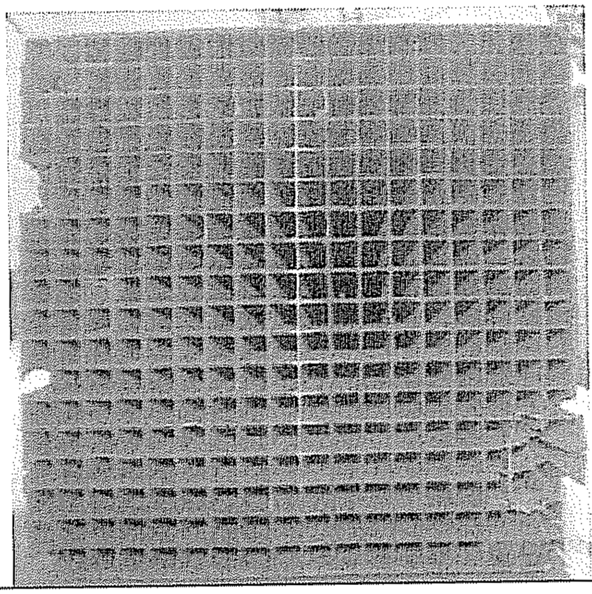
CORMETECH, INC.
Laboratory Services

Western Kentucky Energy
Henderson Unit 1
SCR Catalyst Pilot Performance Test Report
February 7, 2008

<table>
<tr><td colspan="2">ID#: 0312-2961-0241
Layer 2</td></tr>
<tr><td><u>Flow Entrance Face</u>
</td><td rowspan="2"><u>Physical Inspection Observations:</u>

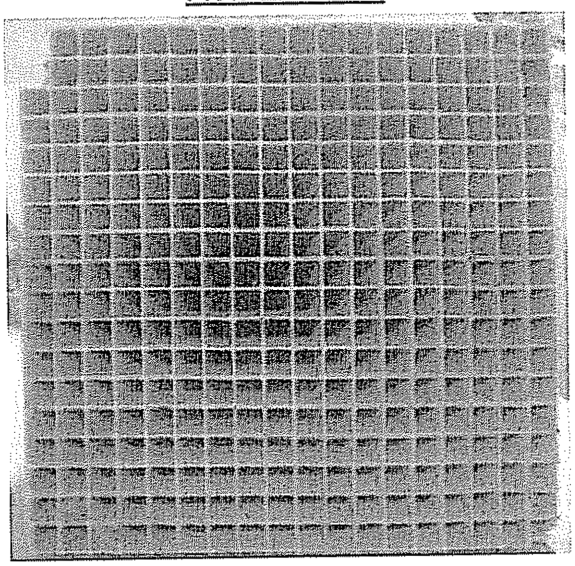
Sleeve Marking: H-1 #58 middle layer 10-3-07 Western Kentucky Energy HMPL Unit-1

Box Marking: H-1 #58 middle layer 10-3-07

Cell Count: 18 x 18 shaved

Plugged Cells
Initial: 12 Final: 0

Length: 1206 mm

Inspection Notes: Some surface cracks on the shaved side.</td></tr>
<tr><td><u>Flow Exit Face</u>
</td></tr>
</table>

Results of Laboratory Tests- Pilot

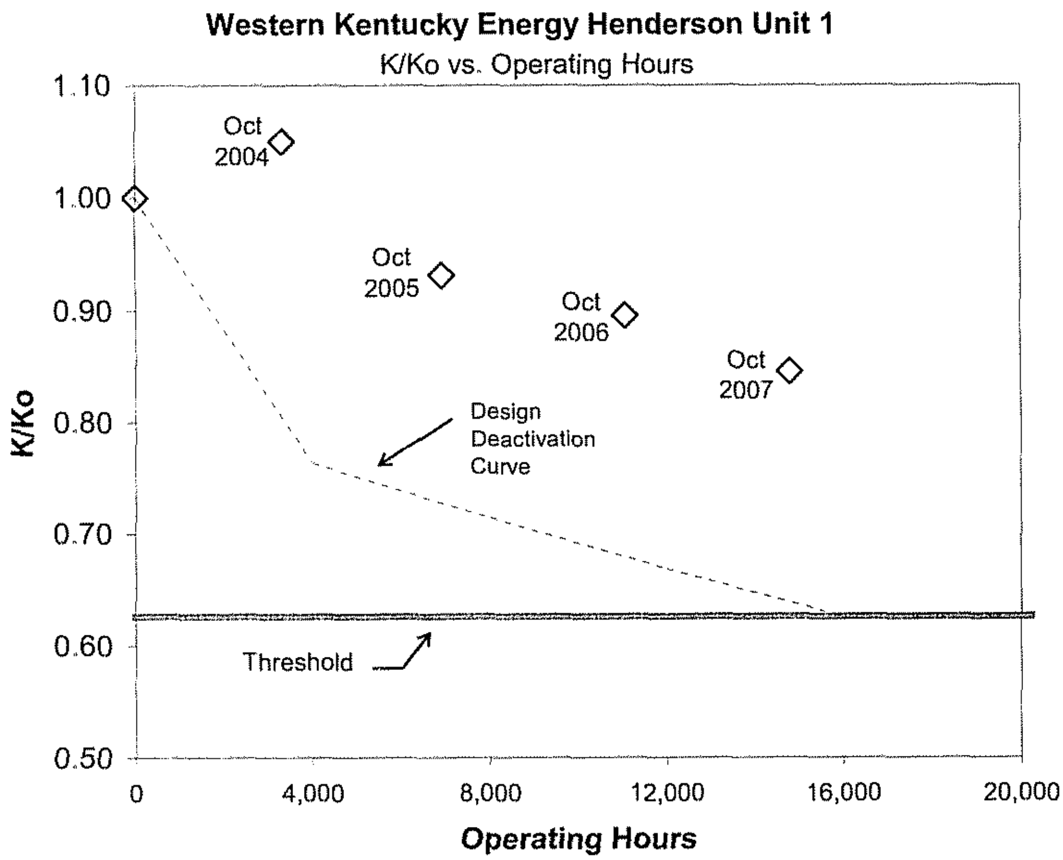
The catalyst performance was measured and is reported as K/Ko. K/Ko is a measure of the change in catalytic potential relative to fresh catalyst. A K/Ko of 0.50 would indicate that the catalyst potential of the field sample had declined to one-half of the fresh potential.

The lab performance threshold (based on design scale-up factors), represents the design K/Ko, as measured in the *pilot* reactor, at which the actual *field* performance at *design* operating conditions is expected to reach end-of-life. Field performance is based on a design performance requirement of 90% NO_x removal efficiency and 2 ppmvdc ammonia slip.

In field scale (actual) operation, flow, temperature, and ammonia/NOx nonuniformities exist. In the highly controlled laboratory environment these nonuniformities do not exist, therefore the lab results must be scaled-up to reflect expected field performance. The scale-up factors limit achievable NOx reduction performance in operating SCR systems. The performance threshold value is based on design values for the scale-up factors. The *actual* threshold may be lower if actual scale-up is less severe, or higher if more severe.

	Element Identification	Time On-Line (Hours)	K/Ko
Fresh Reference		0	1.00
November 2004	0508-2960-0245 0312-2961-0232	3,333	1.05
October 2005	0508-2960-0284 0307-1960-0234	6,931	0.93
October 2006	0508-2960-0283 0508-2960-0300	11,062	0.90
October 2007	0508-2960-0249 0312-2961-0241	14,808	0.85
Threshold (based on design scale-up factors)			0.63

The figure below shows the trend in catalyst performance.



This audit of the Western Kentucky Energy Henderson Unit 1 SCR catalyst shows a decrease in catalytic potential of the SCR catalyst, as measured by pilot-scale testing.

Based on the results of this audit, the SCR catalyst installed in Western Kentucky Energy Henderson Unit 1 is above the performance threshold and is projected to continue to meet the design field performance requirements of 90% NO_x reduction at 2 ppmvdc ammonia slip for at least the period of the guarantee life.

RECOMMENDATIONS

The catalytic potential for Western Kentucky Energy Henderson Unit 1 remains above the performance threshold required for the SCR system to meet the design performance requirement of 90% NO_x removal efficiency and 2 ppmvdc ammonia slip. Cormetech recommends auditing the catalytic potential at Cormetech's laboratory after one year of additional operation.

APPENDIX 1: Location of Sample Retrieval

North

Both Layers

5	15	25	35	45	**55**
6	16	**26**	36	**46**	56
7	17	27	37	47	57
8	18	28	38	48	**58**
9	19	**29**	39	**49**	59
10	20	30	40	50	60
4	14	24	34	44	**54**
3	13	**23**	33	**43**	53
2	12	22	32	42	52
1	11	21	**31**	41	**51**

Denotes 2007 sampling location

Denotes previous sample location

Denotes alternate sample location

APPENDIX 2: Field Records

Western Kentucky Energy
Catalyst Information: CONFIDENTIAL

Plant	HMP&L Station Two	HMP&L Station Two
Unit	Unit 1	Unit 2
Capacity (Gross/Net)	154 MW Net	161 MW Net
Number of Reactors per Unit	1	1
Total # of layers	3	3
Layers in use	2	2
Modules per layer	60	60
Volume per layer	117 cu meters	117 cu meters
Catalyst Manufacturer	Cormetech	Cormetech
Type	Honeycomb	Honeycomb
Composition	V - W - Ti	V - W - Ti
Start Activity	n/a	n/a
Surface Area (m2/m3)	502	502
Av (testing through 2 layers)	10	10
Catalyst Pitch	7.1 mm	7.1 mm
Catalyst Length	1209 mm	1209 mm
Number of plates per module	n/a	n/a
Number of elements per module	72	72
Date of SCR start up	11/3/2003	4/14/2004
Date of sampling	Oct 3,2007	Oct.10, 2005
Operating hours at sampling date	14,808	13,840
Year round operation (Yes/No)	No	No
Bypass available (Yes/No)	Yes	Yes
Load (base load or cycled)	Base Loaded	Base Loaded
# of start and stops	n/a	n/a
Catalyst Test Conditions		
Actual flue gas flow per unit (acfm)	960,000 **	960,000 **
Operating Temperature		
Design	750 deg F	750 deg F
Actual (Test)	673 deg F	673 deg F
Inlet Nox (ppm dry) @3.0% O2	301 ppm design	301 ppm design
Actual flue gas composition		
SO2 inlet (ppm dry) @ 3.0% O2	3300 design **	3300 design **
SO3 inlet (ppm dry)	39.2 design **	39.2 design **
O2 inlet (% by vol dry)	3.0 design **	3.0 design **
H2O inlet (% by vol wet)	8.0 design **	8.0 design **

APPENDIX 3: Performance Test Standard Procedure

Purpose

The *laboratory performance testing* for SCR catalyst is conducted to determine the catalytic potential of a representative sample of SCR catalyst at conditions that closely match the actual operating conditions of the SCR system. The sample should represent a typical cross section of the SCR, and the operating history should be known. The test is conducted in a controlled, laboratory environment on custom-built, rigorously validated SCR catalyst test apparatus allowing accurate determination of performance and comparisons of the sample catalytic potential to the system requirements previously tested catalyst(s).

Test Equipment Description

The Cormetech Laboratory SCR test reactors consist of three basic systems:

- Simulated flue gas generator
- SCR catalyst test chamber
- Measurement system

The purpose of the simulated flue gas generator is to provide a stable controlled supply of heated gas with the required mix of gases at the required flow rate and temperature to the SCR catalyst test chamber. It consists of a bulk flue gas generator, a flue gas modification system, a flue gas heater, a reactive gas injection system, and a flue gas mixer.

Bulk Flue Gas Generator - The bulk flue gas is produced by either the combustion of air in a natural gas fired water-cooled combustion chamber, the extraction of nitrogen from air via a membrane system, or the delivery of nitrogen from liquefied nitrogen. This system is adjusted to achieve the overall flue gas flow rate required for the specified test.

Flue Gas Modification System - The gas stream produced by the bulk flue gas generator is modified by the addition of oxygen/air and water/steam to achieve the targeted concentrations of water vapor and oxygen in the flue gas stream.

Flue Gas Heater - The flue gas stream is heated to the target test temperature by an electric pre-heater.

Reactive Gas Injection System - Calibrated mass flow controllers are used to deliver SO_2, SO_3, NO_2, NO, and NH_3 into the flue gas stream.

The table below summarizes the range of process conditions that can be produced by various apparatus in Cormetech's laboratory. Cormetech's laboratory maintains multiple testing units, each with varying capabilities for temperature, flow, and gas composition. The unit selected for a given test will depend on the specific requirements for the sample tested.

Parameter	Units	Range
Gas Temperature	^{o}C	200 – 600
Flow rate/Entrance velocity	Nm/s	1.25 - 7.05
O_2	volume % dry	1 – 20
H_2O	volume %	1-20[1]
NO	ppmvd	0 - 2,000
NO_2	ppmvd	0 - 2000[2]
NH_3	ppmvd	0 - 4,000
SO_2	ppmvd	0 - 2,000
SO_3	ppmvd	0 – 25

1: Some apparatus have the capability to control water concentration. Other units supply water as a product of combustion. When water concentration is not controlled, Cormetech corrects the results to the target concentration with a standardized correction factor.
2: NO_2 addition capability is not available on all test units.

Flue Gas Mixer - Following the reactive gas injection, the gases are mixed using a high efficiency static mixing element.

The simulated flue gas next enters the SCR test reactor where the SCR test sample or samples are located. Each sample is sealed tightly to the walls of the test chamber to ensure that all of the flue gas passes though the sample[s]. Along the length of the test chamber there are electric heating elements that maintain the specified test temperature. There are test ports located at the entrance to the test reactor and at the exit of each sample layer to extract a sample of flue gas for analysis, measure the static pressure of the flue gas, and monitor the temperature of the catalyst samples and the flue gas.

The process conditions of the SCR catalyst under test are monitored by the measurement system:

Gas Flow Rate - The flue gas flow rate is measured by an averaging pitot tube in the exit of the simulated flue gas generator. The flow rate is also calculated from the mass flow controllers for the various gas constituents as they are added. Finally, an annubar is installed in the exhaust of the reactor which allows another cross-check of the flow rate. For the testing to be determined valid, the flow rate must be within the allowable limits from the target flow rate.

Gas Temperature - The temperature of the gas and the catalyst samples is measured by a series of thermocouples throughout the test reactor. For the testing to be determined valid, both the spatial and temporal variability must be within the allowable limits from the specified set point.

Component Concentration - The components of the flue gas are determined by the methods described below. Different systems may not have every type of sampling measurement system.

- NO_x - Chemiluminescent NO_X Analyzer / Infrared Spectroscopy. Average value at each sampling point recorded for each sampling cycle
- NH_3 - Ion Chromatography/infrared spectroscopy
- SO_2 - Precipitation Method/infrared spectroscopy
- SO_3 - Controlled Condensation; Collective Precipitation Method
- O_2 - Micro-fuel cell and Paramagnetic O2 Analyzer

<u>Procedure Description Summary</u>

The following stepwise description is a guideline to understand how an audit proceeds from sample receipt to reported results.

1. Upon receipt, each sample is inspected for condition and photographed. The sample dimensions are recorded.

2. The Test Plan is prepared based on the needs of audit. The appropriate test apparatus is selected based on the test requirements and the test is scheduled.

3. Each sample is prepared for testing. [This process includes cleaning the sample, and cutting to the required test sample size.]

4. The reactor is opened, inspected, and prepared for operation.

5. Each catalyst sample is loaded according to the Test Plan and sealed in the reactor.

6. An equipment leak test is performed.

7. The Bulk Flue Gas Generator is started and the test conditions are set for O_2%, temperature, and bulk flow rate.

8. NO and NO_2 injection is started and then adjusted in order to meet the test conditions.

9. Ammonia, SO_2 and SO_3 injection is started and then adjusted in order to meet the test conditions.

10. The catalyst is allowed to equilibrate at the test conditions specified.

11. A calibration check is run for the analyzers.

12. For each sampling cycle, the following measurements are taken, as required:

Item	Location Measured	Frequency
NO_X Concentration	Multiplexed to measure NO_X at each sampling point	Average value at each sampling point recorded per each sampling cycle
NH_3 Concentration	At exit of sample[s]	Depends on test method [Multiple analyses recorded]
SO_2 Concentration	Entrance and at each sampling port	When SO_2 oxidation performance is measured
SO_3 Concentration	Entrance and at each sampling port	When SO_2 oxidation performance is measured
O_2 Concentration	Exit of combustion chamber and multiplexed with NO_X Analyzer	Continuously controlled and monitored
Gas Flow	Exit of combustion chamber	Continuously controlled and monitored
Gas Temperature	At each sampling port	Inlet continuously controlled
Pressure Drop	Entrance and at exit of testing chamber	Continuously monitored, recorded as required

13. The results are recorded and checked per Quality Assurance requirements and compared to the Test Plan.

14. The results are reported.

CORMETECH

Western Kentucky Energy
Henderson Unit 2
For Alstom

SCR Catalyst
Pilot Performance Test Report
13,840 Operating Hours
42 Months Since First Gas-In

Submitted by

CORMETECH, INC.
Environmental Technologies
5000 International Drive
Durham, NC 27712
(919) 620-3000

Mark Schirmer
Senior Project Manager

Mark A Conger

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Certifying Laboratory Representative:
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February 7, 2008

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- The performance expectations for the unit

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Performance Requirements: If the actual plant performance requirements are more stringent than the design performance requirements, actual life will be less than design life. An example of this would be a unit that was designed to achieve a certain NO_x reduction at given ammonia slip, but is actually required to achieve a higher NO_x reduction.

Operating Conditions: Flue gas flow rate, inlet NO_x levels, temperature, oxygen content, and water content impact catalytic potential. If the catalyst is at an operating condition where the potential is lower than design, actual life will be less than design life.

Scale-Up Factors: The full NOx reduction potential of the catalyst is not attained in the field due to non-ideal flow distribution, temperature distribution, ammonia to NOx molar ratio distribution, catalyst blockage, and/or flue gas bypass. Collectively, these non-ideal conditions are accounted for with 'system scale-up factors'. If the overall actual system scale-up factors are more severe than the design scale-up factors, then the potential of the SCR system to meet a given performance requirement is reduced.

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If any or all of the first three parameters; namely, performance requirements, operating conditions, and scale-up factors, are more stringent than the initial design, then less margin for catalyst deactivation remains. Therefore, actual life will be less than design life.

At any given time and operating condition, the SCR system performance is dictated by the NO_x reduction potential of the catalyst and the system scale-up factors. These factors reduce performance from the catalytic potential to the performance achievable in the operating SCR system.

Pilot performance tests are purposefully conducted in a controlled environment, free from the scale-up factors that adversely affect SCR system performance, and at repeatable operating conditions so that changes in catalytic potential may be evaluated accurately. Catalyst deactivation can be determined by testing the field catalyst sample at the same operating conditions as the test of the fresh sample and assigning the relative change in catalytic potential to catalyst deactivation.

In conjunction with pilot test results, analysis of field SCR system performance data can confirm: the field performance requirements, the plant operating conditions, and actual system scale-up factors.

Cormetech's SCR catalyst design and testing experience enables analysis of the actual versus design values of: performance requirements, operating conditions, system scale-up, and catalyst deactivation to predict future catalyst performance.

FACILITY OPERATIONAL HISTORY

Western Kentucky Energy Henderson Unit 2 is Pulverized Coal Unit. The SCR system consists of a single reactor. The reactor currently contains two layers of Cormetech 7.1 mm pitch catalyst. The SCR was put into operation in April, 2004.

In December, 2004 catalyst samples were removed for testing. At the time the samples were removed, the SCR had accumulated 3,173 operating hours. This report summarizes the results of this previous audit.

On December 3, 2005 catalyst samples were removed for testing. At the time the samples were removed, the SCR had accumulated 6,817 operating hours. This report summarizes the results of this previous audit.

On October 14, 2006 one sample was removed from each layer and returned to Cormetech for laboratory testing. At the time the samples were removed, the SCR had accumulated 10,231 operating hours. This report summarizes the results of this previous audit.

On October 10, 2007, one sample was removed from each layer and returned to Cormetech for laboratory testing. At the time the samples were removed, the SCR had accumulated 13,840 operating hours. This report summarizes the results of the audit.

PROCEDURE OVERVIEW

1. One catalyst sample was removed from the field sampler in each layer at the Western Kentucky Energy Henderson Unit 2 SCR. The samples were shipped to Cormetech's laboratory. Operating history was recorded by the Generating Station and forwarded to Cormetech.

2. The physical condition of the catalyst was documented by Cormetech.

3. The catalyst was loaded into a Pilot Activity Test Apparatus and then evaluated at the *design* conditions for the plant SCR. The Pilot Activity Test Procedure Standard is included in Appendix 3.

4. The results include catalyst potential expressed as K/Ko.

5. Test results were compared to design. Expectations of catalyst deactivation were determined by the time on-line, experience data of similar coal-fired facilities, and fresh catalyst performance.

6. An expected catalyst life prediction is based on the above testing and analysis.

FIELD SAMPLING AND UNIT OPERATING CONDITIONS

Field Sampling

One catalyst sample was removed from the field sampler in each layer at the Western Kentucky Energy Henderson Unit 2 SCR was removed and sent to Cormetech's Laboratory for evaluation.

Operating Status:

Field records supplied by Western Kentucky Energy are summarized in the table below.

First Gas-In Date with Catalyst Installed	April, 2004
Sample Removal Date	October 10, 2007
Total Operating Hours On Catalyst Sample	13,840
Primary Fuel Fired	Blend

LABORATORY PERFORMANCE TEST CONDITIONS

A pilot test was conducted on the sample received using the conditions below. These conditions reflect the *original* pilot test condition for which there is fresh catalyst test data available for direct comparison.

Temperature	356 °C (673 °F)
Area Velocity	10.0 Nm/h
O_2, vol. %, dry	3.10%
Inlet NO_x ppmvd	299.3 @ 3.10% O_2 (301.0 @ 3% O_2)

RESULTS

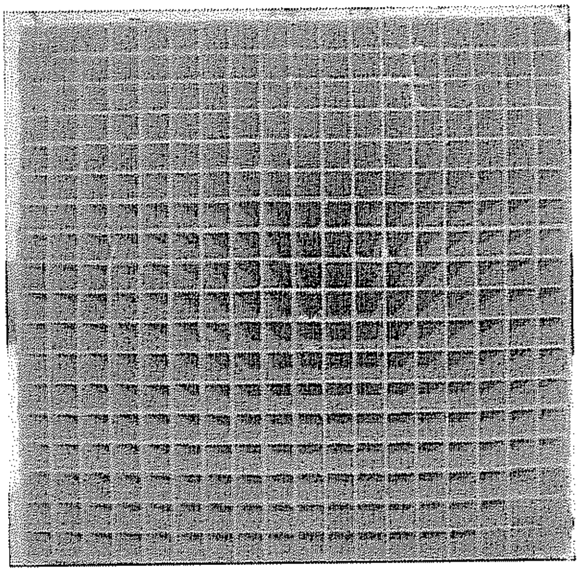
Physical Inspection

The figures on the following pages show photographs of the flow entrance face and the flow exit face of the element as they arrived at Cormetech.

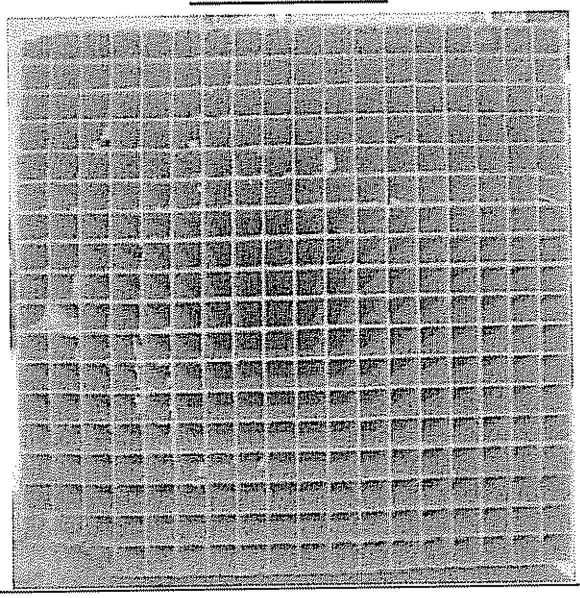
All the samples received were 18 cells x 18 cells and exhibit plugged cells in two opposite corners. This is a result of the sample tray design as does not affect the results of the testing. The testing of the elements was not adversely impacted by the element condition.

ID #: 3016-3268-0279
Layer 1

Flow Entrance Face



Flow Exit Face



Physical Inspection Observations:

Sleeve Marking: H-2 top layer #58 10-10-07 Western Kentucky Energy HMPL Unit-2

Box Marking: Henderson unit-2 Box: H-2 #58 Top layer 10-10-07

Cell Count: 18 x 18 shaved

Plugged Cells

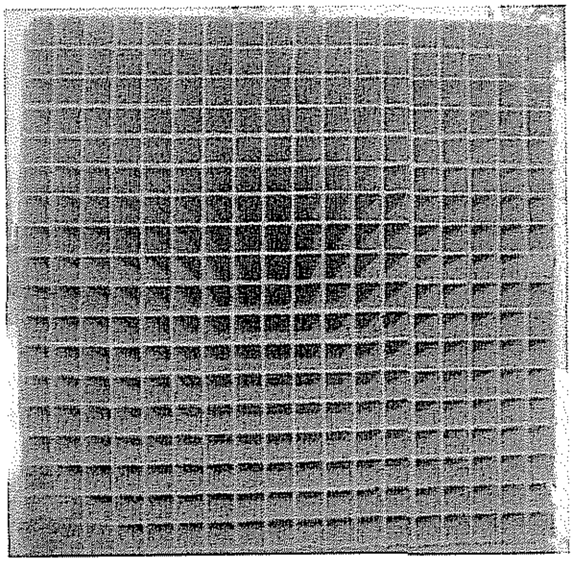
Initial: 13 Final: 0

Length: 1205 mm

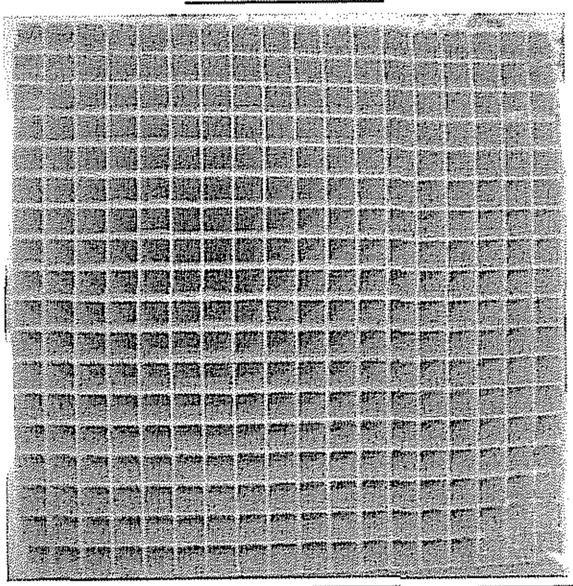
Inspection Notes: Element in good condition

ID#: 3016-3268-0282
Layer 2

Flow Entrance Face



Flow Exit Face



Physical Inspection Observations:

Sleeve Marking: H-2 #58 middle layer 10-20-07 Western Kentucky Energy HMPL Unit-2

Box Marking: H-2 #58 middle layer 10-10-07

Cell Count: 18 x 18 shaved

Plugged Cells

Initial: 12 Final: 0

Length: 1205 mm

Inspection Notes: Some edge damage and surface damage on shaved side. This will not effect testing.

Results of Laboratory Tests- Pilot

The catalyst performance was measured and is reported as K/Ko. K/Ko is a measure of the change in catalytic potential relative to fresh catalyst. A K/Ko of 0.50 would indicate that the catalyst potential of the field sample had declined to one-half of the fresh potential.

The *lab performance* threshold (based on design scale-up factors), represents the design K/Ko, as measured in the *pilot* reactor, at which the actual *field* performance at *design* operating conditions is expected to reach end-of-life. Field performance is based on a design performance requirement of 90% NO_x removal efficiency and 2 ppmvdc ammonia slip.

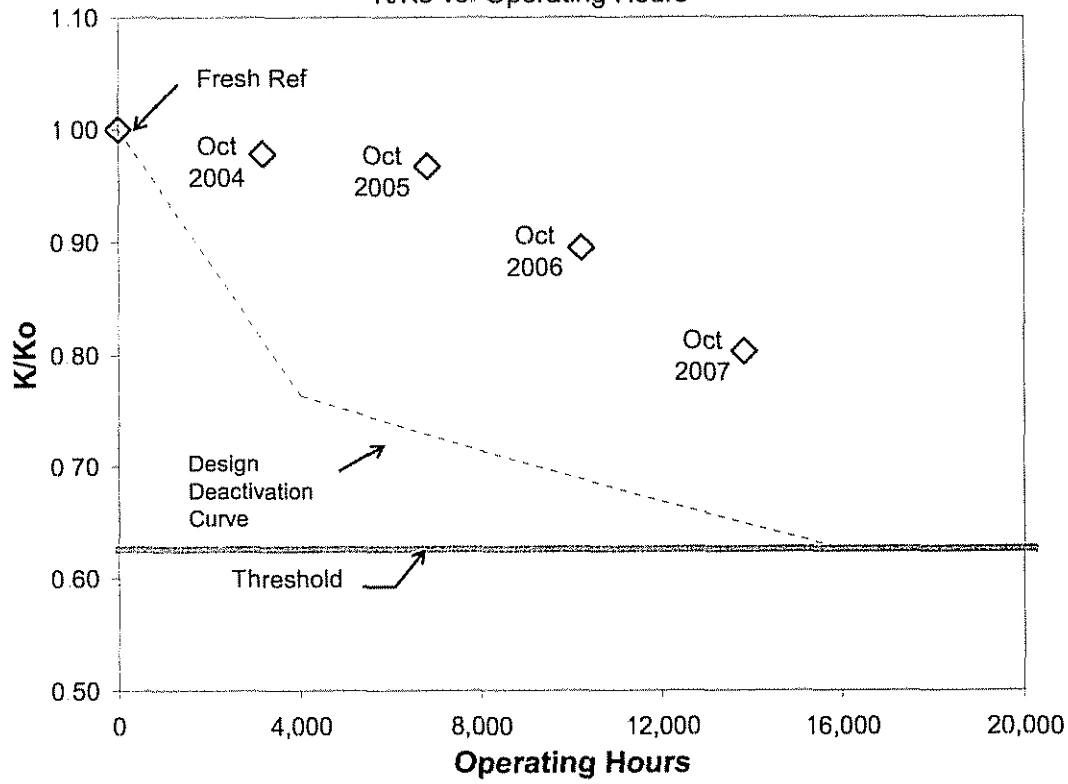
In field scale (actual) operation, flow, temperature, and ammonia/NOx nonuniformities exist. In the highly controlled laboratory environment these nonuniformities do not exist, therefore the lab results must be scaled-up to reflect expected field performance. The scale-up factors limit achievable NOx reduction performance in operating SCR systems. The performance threshold value is based on design values for the scale-up factors. The *actual* threshold may be lower if actual scale-up is less severe, or higher if more severe.

	Element Identification	**Time On-Line** (Hours)	**K/Ko**
Fresh Reference		0	1.00
November 2004	Hed2-1_05-0114 3016-3268-0280	3,173	0.98
December 2005	3016-3268-0291 3016-3268-0278	6,817	0.97
October 2006	3016-3268-0230 3016-3268-0312	10,231	0.90
October 2007	3016-3268-0279 3016-3268-0282	13,840	0.80
Threshold (based on design scale-up factors)			0.63

The figure below shows the trend in catalyst performance.

Western Kentucky Energy Henderson Unit 2

K/Ko vs. Operating Hours



This audit of the Western Kentucky Energy Unit 2 SCR catalyst shows a decrease in catalytic potential of the SCR catalyst, as measured by pilot-scale testing.

Based on the results of this audit, the SCR catalyst installed in Western Kentucky Energy Unit 2 is above the performance threshold and is projected to continue to meet the design field performance requirements of 90% NO_x reduction at 2 ppmvdc ammonia slip for at least the period of the guarantee life.

RECOMMENDATIONS

The catalytic potential for Western Kentucky Energy Henderson Unit 2 remains above the performance threshold required for the SCR system to meet the design performance requirement of 90% NO_x removal efficiency and 2 ppmvdc ammonia slip. Cormetech recommends auditing the catalytic potential at Cormetech's laboratory after one year additional operation.

APPENDIX 1: Location of Sample Retrieval

North →

Both Layers

5	15	25	35	45	**55**
6	16	**26**	36	**46**	56
7	17	27	37	47	57
8	18	28	38	48	**58**
9	19	**29**	39	**49**	59
10	20	30	40	50	60
4	14	24	34	44	**54**
3	13	**23**	33	**43**	53
2	12	22	32	42	52
1	11	21	**31**	41	**51**

Denotes 2007 sampling location

Denotes previous sample location

Denotes alternate sample location

APPENDIX 2: Field Records

Western Kentucky Energy
Catalyst Information: CONFIDENTIAL

Plant	HMP&L Station Two	HMP&L Station Two
Unit	Unit 1	Unit 2
Capacity (Gross/Net)	154 MW Net	161 MW Net
Number of Reactors per Unit	1	1
Total # of layers	3	3
Layers in use	2	2
Modules per layer	60	60
Volume per layer	117 cu meters	117 cu meters
Catalyst Manufacturer	Cormetech	Cormetech
Type	Honeycomb	Honeycomb
Composition	V - W - Ti	V - W - Ti
Start Activity	n/a	n/a
Surface Area (m2/m3)	502	502
Av (testing through 2 layers)	10	10
Catalyst Pitch	7.1 mm	7.1 mm
Catalyst Length	1209 mm	1209 mm
Number of plates per module	n/a	n/a
Number of elements per module	72	72
Date of SCR start up	11/3/2003	4/14/2004
Date of sampling	Oct 3,2007	Oct.10, 2005
Operating hours at sampling date	14,808	13,840
Year round operation (Yes/No)	No	No
Bypass available (Yes/No)	Yes	Yes
Load (base load or cycled)	Base Loaded	Base Loaded
# of start and stops	n/a	n/a
Catalyst Test Conditions		
Actual flue gas flow per unit (acfm)	960,000 **	960,000 **
Operating Temperature		
Design	750 deg F	750 deg F
Actual (Test)	673 deg F	673 deg F
Inlet Nox (ppm dry) @3 0% O2	301 ppm design	301 ppm design
Actual flue gas composition		
SO2 inlet (ppm dry) @ 3 0% O2	3300 design **	3300 design **
SO3 inlet (ppm dry)	39.2 design **	39.2 design **
O2 inlet (% by vol dry)	3.0 design **	3.0 design **
H2O inlet (% by vol wet)	8.0 design **	8.0 design **

APPENDIX 3: Performance Test Standard Procedure

Purpose

The *laboratory performance testing* for SCR catalyst is conducted to determine the catalytic potential of a representative sample of SCR catalyst at conditions that closely match the actual operating conditions of the SCR system. The sample should represent a typical cross section of the SCR, and the operating history should be known. The test is conducted in a controlled, laboratory environment on custom-built, rigorously validated SCR catalyst test apparatus allowing accurate determination of performance and comparisons of the sample catalytic potential to the system requirements previously tested catalyst(s).

Test Equipment Description

The Cormetech Laboratory SCR test reactors consist of three basic systems:

- Simulated flue gas generator
- SCR catalyst test chamber
- Measurement system

The purpose of the simulated flue gas generator is to provide a stable controlled supply of heated gas with the required mix of gases at the required flow rate and temperature to the SCR catalyst test chamber. It consists of a bulk flue gas generator, a flue gas modification system, a flue gas heater, a reactive gas injection system, and a flue gas mixer.

Bulk Flue Gas Generator - The bulk flue gas is produced by either the combustion of air in a natural gas fired water-cooled combustion chamber, the extraction of nitrogen from air via a membrane system, or the delivery of nitrogen from liquefied nitrogen. This system is adjusted to achieve the overall flue gas flow rate required for the specified test.

Flue Gas Modification System - The gas stream produced by the bulk flue gas generator is modified by the addition of oxygen/air and water/steam to achieve the targeted concentrations of water vapor and oxygen in the flue gas stream.

Flue Gas Heater - The flue gas stream is heated to the target test temperature by an electric pre-heater.

Reactive Gas Injection System - Calibrated mass flow controllers are used to deliver SO_2, SO_3, NO_2, NO, and NH_3 into the flue gas stream.

The table below summarizes the range of process conditions that can be produced by various apparatus in Cormetech's laboratory. Cormetech's laboratory maintains multiple testing units, each with varying capabilities for temperature, flow, and gas composition. The unit selected for a given test will depend on the specific requirements for the sample tested.

Parameter	Units	Range
Gas Temperature	°C	200 – 600
Flow rate/Entrance velocity	Nm/s	1.25 - 7.05
O_2	volume % dry	1 – 20
H_2O	volume %	1-20[1]
NO	ppmvd	0 - 2,000
NO_2	ppmvd	0 - 2000[2]
NH_3	ppmvd	0 - 4,000
SO_2	ppmvd	0 - 2,000
SO_3	ppmvd	0 – 25

1: Some apparatus have the capability to control water concentration. Other units supply water as a product of combustion. When water concentration is not controlled, Cormetech corrects the results to the target concentration with a standardized correction factor.

2: NO_2 addition capability is not available on all test units.

Flue Gas Mixer - Following the reactive gas injection, the gases are mixed using a high efficiency static mixing element.

The simulated flue gas next enters the SCR test reactor where the SCR test sample or samples are located. Each sample is sealed tightly to the walls of the test chamber to ensure that all of the flue gas passes though the sample[s]. Along the length of the test chamber there are electric heating elements that maintain the specified test temperature. There are test ports located at the entrance to the test reactor and at the exit of each sample layer to extract a sample of flue gas for analysis, measure the static pressure of the flue gas, and monitor the temperature of the catalyst samples and the flue gas.

The process conditions of the SCR catalyst under test are monitored by the measurement system:

Gas Flow Rate - The flue gas flow rate is measured by an averaging pitot tube in the exit of the simulated flue gas generator. The flow rate is also calculated from the mass flow controllers for the various gas constituents as they are added. Finally, an annubar is installed in the exhaust of the reactor which allows another cross-check of the flow rate. For the testing to be determined valid, the flow rate must be within the allowable limits from the target flow rate.

Gas Temperature - The temperature of the gas and the catalyst samples is measured by a series of thermocouples throughout the test reactor. For the testing to be determined valid, both the spatial and temporal variability must be within the allowable limits from the specified set point.

Component Concentration - The components of the flue gas are determined by the methods described below. Different systems may not have every type of sampling measurement system.

- NO_x - Chemiluminescent NO_X Analyzer / Infrared Spectroscopy. Average value at each sampling point recorded for each sampling cycle
- NH_3 - Ion Chromatography/infrared spectroscopy
- SO_2 - Precipitation Method/infrared spectroscopy
- SO_3 - Controlled Condensation; Collective Precipitation Method
- O_2 - Micro-fuel cell and Paramagnetic O2 Analyzer

Procedure Description Summary

The following stepwise description is a guideline to understand how an audit proceeds from sample receipt to reported results.

1. Upon receipt, each sample is inspected for condition and photographed. The sample dimensions are recorded.
2. The Test Plan is prepared based on the needs of audit. The appropriate test apparatus is selected based on the test requirements and the test is scheduled.
3. Each sample is prepared for testing. [This process includes cleaning the sample, and cutting to the required test sample size.]
4. The reactor is opened, inspected, and prepared for operation.
5. Each catalyst sample is loaded according to the Test Plan and sealed in the reactor.
6. An equipment leak test is performed.
7. The Bulk Flue Gas Generator is started and the test conditions are set for O_2%,

temperature, and bulk flow rate.

8. *NO and NO_2 injection* is *started* and then adjusted in order to meet the test conditions.

9. Ammonia, SO_2 and SO_3 injection is started and then adjusted in order to meet the test conditions.

10. The catalyst is allowed to equilibrate at the test conditions specified.

11. A calibration check is run for the analyzers.

12. For each sampling cycle, the following measurements are taken, as required:

Item	**Location Measured**	**Frequency**
NO_X Concentration	Multiplexed to measure NO_X at each sampling point	Average value at each sampling point recorded per each sampling cycle
NH_3 Concentration	At exit of sample[s]	Depends on test method [Multiple analyses recorded]
SO_2 Concentration	Entrance and at each sampling port	When SO_2 oxidation performance is measured
SO_3 Concentration	Entrance and at each sampling port	When SO_2 oxidation performance is measured
O_2 Concentration	Exit of combustion chamber and multiplexed with NO_X Analyzer	Continuously controlled and monitored
Gas Flow	Exit of combustion chamber	Continuously controlled and monitored
Gas Temperature	At each sampling port	Inlet continuously controlled
Pressure Drop	Entrance and at exit of testing chamber	Continuously monitored, recorded as required

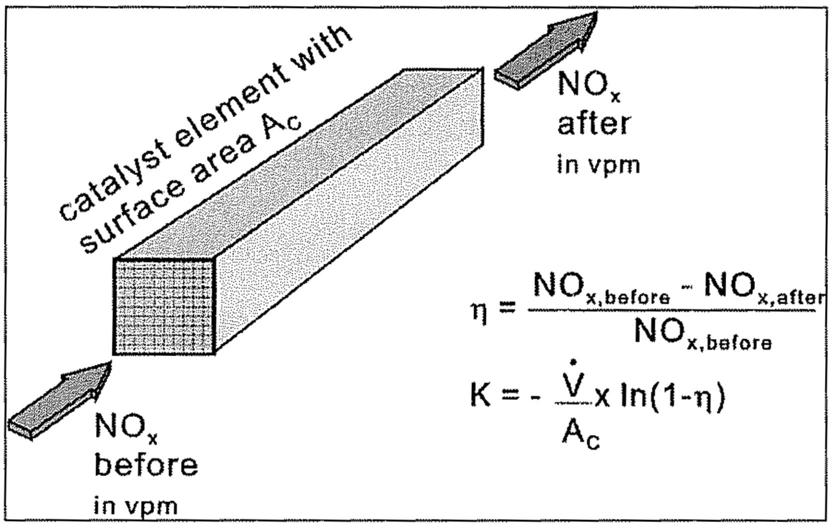
13. The results are recorded and checked per Quality Assurance requirements and compared to the Test Plan.

14. The results are reported.

Engineering Corp.	**Columbus Test Facility**	Name:	Dr. Dinah Dux
		Date:	9-Nov-07
		Phone:	614-836 7272
		Fax:	614-830 0816
		Report-No:	07-WKE-05

Catalyst Test Report – Draft Version
HMP&L Two: Henderson Unit 1 and 2

Sampling: October 2007



Client: Western Kentucky Energy

WESTERN KENTUCKY ENERGY
an e·on company

Address: E ON Engineering Corp., 4001 Bixby RD, Groveport, Ohio 43125

Table of contents

1 Executive Summary

- Based upon the catalyst test elements sampled in October 2007 (14,808 / 13,840 operating hours), Henderson stations' Unit 1 SCR reactor has an effective potential of 4.1 and the SCR reactor of Unit 2 of 4.8. Variation in deactivation is to be expected from different sampling years because of statistical effects. Therefore, considering all test results since 2005, the average expected potential for both units was around 4.5. The required minimum potential is 3.6 (90 % NOx removal efficiency, 2 ppm slip, 301 ppm NOx inlet).
- Provided that the fuels fired and unit operating regime do not significantly change, the SCR reactors of Unit 1 & 2 will be able operate throughout the 2008 OTAG season (approx. 4,000 operating hours). Unit 2 may even be able to operate until the spring outage in 2010.
- The SO_2 to SO_3 conversion coefficients vary from 3.0 to $3.8 \cdot 10^{-2}$ m/h and did not change to prior results. The total SO_2 to SO_3 conversion rate per SCR reactor under typical operation conditions should be fairly low: between 0.3 to 0.5 % are expected.
- The chemical analyses confirmed the changes in chemical composition reported for the last years. Further increase of arsenic occurred during the 2007 ozone season. Arsenic was the main reason for activity loss at Henderson Station.
- The degree of the actual operation margin required for any particular plant can only be determined by physical inspection of the DeNOx plant, ammonia slip testing after the last catalyst layer and sophisticated NOx distribution field testing (e.g. by E.ON's MARA team).
- Different catalyst management strategies were developed within this report. Please refer to section 6.4. EEC will gladly assist HMPL in discussing the different options, in preparing RFQs and in bid evaluation.

EEC		
9-November-07	Dr. Peter Struckmann	Dr. Dinah Dux

2 Task Description

Western Kentucky Energy (WKE) operates four stations to generate electricity. HMP&L Station Two, owned by Henderson Municipal Power and Light, consists of two coal fired plants; Henderson Unit 1 and Unit 2. They went into commercial operation in 1973 / 1974, were retrofitted with scrubbers in mid-1990's and have recently been retrofitted with one SCR reactor each. Both units and their SCR systems are constructed similarly and produce 154 / 161 net-MWs.

WKE requested E.ON Engineering Corporation to determine several characteristic properties of the catalyst material following the German guideline VGB R 302He (Lit. 1).

For this purpose, catalyst samples were pulled from each layer of Henderson Unit 1 and 2 in October 2007. New "unexposed to flue gas" material was tested in 2005.

The obtained bench reactor activity test results were used to calculate the current DeNOx potential and ammonia slip concentration downstream of the last catalyst layer at the time of catalyst sampling.

Utilizing all catalyst samples tested so far, a long term catalyst replacement plan will be discussed within this report, considering different scenarios like adding a third layer and a two layer approach. The scheduled outage plan was considered for this evaluation.

The analysis of changes in the chemical composition of the catalyst provides indicative information regarding the main influences and causes of changes in catalyst activity.

3 Test Methods

According to the VGB guideline (Lit. 1), the catalyst activity and the SO_2 to SO_3 conversion were tested in E.ON's bench scale reactor under the actual SCR operating conditions described in Table 4 (Unit 1 and 2). The gas composition, flue gas velocity and the gas temperature were established at close to the actual full load flue gas conditions of the full-size reactors with the exception of SO_3, which was not injected for bench scale testing.

3.1 Catalyst Activity

The NO_x removal efficiency was determined under steady state conditions. Deviating from the actual operating conditions in the full scale reactor, the bench reactor tests were performed with a molar ratio of NH_3/NOx fixed to 1. The actual activity constant K is defined as follows:

$$K = -AV \times \ln(1 - \eta)$$

K	:	activity constant at $\alpha = 1.0$	[m/h]
$\dot{V}$	:	flue gas volume flow rate	[Nm^3/h]
F	:	catalyst surface	[m^2]
AV	:	area velocity of the test element	[m/h]
η	:	NO_x removal efficiency	[-]

The necessary flue gas volume flow rate for the bench reactor test was calculated by dividing the total volume flow rate at the boiler outlet by the number of honeycombs per layer. Adjustments were made if the catalyst has been cut down from the original channel number and / or if channels were plugged.

3.2 Catalyst SO_2 to SO_3 Conversion Rate and Conversion Coefficient

In accordance with the VGB guideline (Lit. 1), the catalyst SO_2 conversion was measured without ammonia in the flue gas ($\alpha = 0$). As the NO_x removal and the SO_2 oxidation are competitive chemical reactions, the catalyst SO_2 conversion determined without ammonia is the largest, "worst case" value to be expected. The catalyst SO_2 conversion usually decreases when ammonia is added to the flue gas. The measured SO_2 conversion coefficient (K_{SO2}) is defined as follows:

$$K_{SO_2} = AV_{Test}\left(\frac{SO_{3,after} - SO_{3,before}}{SO_{2,before}}\right) \times 100\ \% \qquad AV_{test} = \left(\frac{\dot{V}_{test}}{A_{test}}\right)$$

K_{SO2}	SO_2 to SO_3 conversion coefficient	[10^{-2} m/h]
$SO_{3,after}$	sulfur trioxide concentration after test element	[ppmvd, act. O_2]
$SO_{3,before}$	sulfur trioxide concentration before test element	[ppmvd, act. O_2]
$SO_{2,before}$	sulfur dioxide concentration before test element	[ppmvd, act. O_2]
AV_{test}	area velocity in the test element	[m/h]
$\dot{V}_{test}$	flue gas flow rate in test element	[STP m^3/h]
A_{test}	exposed surface area of test element	[m^2]

The SO_2 to SO_3 conversion rate for each catalyst layer was calculated by dividing the measured SO_2 to SO_3 conversion coefficient by the area velocity in the SCR.

$$k_{SO_2} = \frac{K_{SO_2}}{AV_{SCR}}$$

k_{SO2}	SO_2 to SO_3 conversion rate	[%]
K_{SO2}	SO_2 to SO_3 conversion coefficient	[10^{-2} m/h]
AV_{SCR}	area velocity in the SCR	[m/h]

3.3 Chemical Composition

The chemical composition of the catalyst material was determined by using x-ray fluorescence analysis. For each catalyst sample two different analyzing methods were used.

To estimate the influence of intrusive elements such as arsenic, soluble and mobilized alkali salts and/or phosphorus, portions of the catalyst were ground to a fine powder. Changes in the bulk chemistry characterize intrusion of gaseous and soluble liquid catalyst poisons.

To identify masking and plugging effects on the catalyst surface, the catalyst surface was analyzed as received without sample preparation. Differences between bulk and surface analyses characterize the formation of surface layers, blinding or pore blocking.

Chemical analysis was performed on both the inlet and outlet section of each individual catalyst layer separately to determine any within layer or layer to layer dependent effects. Within the first 100 mm the flow conditions in the catalyst channels change from turbulent to laminar. Therefore the entrance section can be utilized to detect absolute chemical changes very clearly. However, the exit section is far more representative for the quantitative effect of the chemical changes.

To correlate the activity loss to chemical changes, it is important to use so called "weighted average values" for the respective chemical elements. In E.ON's experience the best results are obtained when 20 % of the inlet values are combined to 80 % of the outlet values.

4 Catalyst Design Data and Geometric Values of the Test Element

The relevant design and operational data of the installed catalyst material in Henderson Unit 1 & 2 are summarized in Table 5. The catalyst beds have each a volume of 117 m^3 and are equipped with 60 modules. Every module is filled with 72 Cormetech honeycombs with a length of 1209 mm. The catalyst pitch is 7.1 mm and the specific catalyst surface (A_p) is 502 m^2/m^3.

E.ON Engineering Corp. received honeycombs in steel test boxes from each layer to perform the laboratory tests. The honeycombs were cut down from 21x21 channels to 18x18 channels by Cormetech to fit into the steel test boxes. The number of plugged channels per honeycomb varied between 11 and 20, this is considered low plugging. The flue gas volume flow was adjusted proportionally to the number of existing, free channels for each honeycomb (Tables 6/7). The honeycombs were removed from the steel boxes prior to bench scale testing.

According to the instructions of the VGB guideline (Lit. 1), the total surface of one honeycomb was determined to be around 9.25 m^2.

5 Test Results

5.1 Catalyst Activity

The activity test results are listed below and in Tables 6/7 in the appendix. All catalyst samples have seen flue gas during four ozone seasons, due to pre-tests, outages and trips the exact operating hours varies between the units.

Henderson	Operating Hours	Start Activity K_0	Activity Constant Layer 1	Activity Constant Layer 2
Unit 1	14,808 h	44.6 m/h	29.8 m/h	31.4 m/h
Unit 2	13,840 h		34.7 m/h	35.8 m/h

Table 1: Catalyst Activity Constants

Unit 1 samples showed deactivation around 30 %, which is in a typical range for the operating hours and coal type fired. The average activity loss of Unit 2 samples was with 22 % a little bit lower compared to Unit 1.

Figures 1 and 2 in the appendix show the trend of activity over time for both units, including all test points determined up to date. Some variation between the different years to the average trend is obvious, but was expected. The reason therefore lies in deactivation variation throughout one catalyst layer. Each layer contains 4,320 honeycombs and since the flue gas flow and ash accumulation is mostly not homogeneous throughout the full layer, the deactivation can also vary. Future catalyst testing will improve these graphs.

5.2 Catalyst SO_2 to SO_3 Conversion Coefficient and Conversion Rate

The complete results of the measured SO_2 to SO_3 conversion coefficient and SO_2 to SO_3 conversion rates per catalyst layer are shown below and in 6/7 in the appendix and below. All samples showed conversion coefficients within in the same range.

	SO_2 Conversion New Material	Layer 1 SO_2 Conversion		Layer 2 SO_2 Conversion	
		Coefficient	Rate	Coefficient	Rate
Unit 1	$3.3 \cdot 10^{-2}$ m/h 0.27 %	$3.1 \cdot 10^{-2}$ m/h	0.26 %	$3.8 \cdot 10^{-2}$ m/h	0.32 %
Unit 2		$3.0 \cdot 10^{-2}$ m/h	0.25 %	$3.3 \cdot 10^{-2}$ m/h	0.27 %

Table 2: SO_2 to SO_3 Conversion Test Results

The SO_2 to SO_3 conversion rate per full reactor (2 layers) is between 0.5 % and 0.6 % and did not change compared to the initial installation. The SO_2 conversion rate was measured at a molar NH_3/NOx ratio of zero without ammonia (α = 0). Regarding the reducing impact of ammonia on the conversion rate, lower values are to be expected for the full-scale reactor. As the molar ratio (α) changes from layer to layer with operation time, it is difficult to calculate the exact total SO_2 conversion rate at the full- scale reactor.

Based on E.ON's experience, a total SO_2 to SO_3 conversion rate per SCR reactor under the typical operation conditions of α= 0.9 at the reactor inlet is expected to be:

Unit 1 / 2: 0.3 to 0.5 % per SCR reactor

A more accurate SO_2 to SO_3 conversion rate of the SCR reactor can only be determined by means of in-situ flue gas measurements up- and downstream of the SCR reactor.

5.3 Chemical Composition of the Catalyst Material (Bulk and Surface)

The chemical analysis results of the catalyst material are summarized in Tables 11 and 12 in the appendix.

The honeycomb catalysts are of a ceramic type with the main constituent being TiO_2. Compounds like tungsten and vanadium ensure the activity of the material; their concentration may vary due to manufacturing processes. The SiO_2, Al_2O_3 and CaO concentration of the material are part of the silicate glass fibers which are incorporated into the TiO_2 bulk material to improve the mechanical strength of the catalytic ceramic mass. Other elements like phosphorus, alkali or alkaline earth metals are only present as trace elements in unexposed catalyst material.

The chemical analysis showed an ongoing accumulation of catalyst poisons parallel to the trend of the past years.

After approx. 14,000 operating hours, both units showed slightly elevated concentrations for calcium oxide (CaO), sodium oxide (Na_2O) and potassium oxide (K_2O) in the catalyst bulk material. On the catalyst surface, Unit 1 samples contained higher amounts of alkali and alkaline earth metals than Unit 2. The same was found for the accumulation of sulfates on the catalyst surface: Unit 1 had 3.2 to 3.4 % sulfur oxide (SO_3) and Unit 2 showed 2.5 to 2.7 %. The phosphorus concentration was also slightly elevated on the catalyst surfaces. The combination of calcium oxide (CaO) and sulfur oxide (SO_3) and / or phosphor oxide (P_2O_5) can cause the formation of a so called blinding layer; this is a dense surface layer which inhibits the flue gas from reaching the catalyst material. The determined concentrations were still on a low level but indicate the early state of local sulfate depositions.

The increased amounts of silica, alumina and iron on the catalyst surface were caused by fly ash deposits.

The main compound responsible for the activity loss was arsenic, which is a very strong catalyst poison. The chemical analysis showed that the arsenic amount continued to rise. Weighted arsenic concentrations in the catalyst bulk material were 2,589 ppm (Layer 1) / 1,750 ppm (Layer 2) for Unit 1 and 2,171 ppm / 1,499 ppm for Unit 2. Stronger accumulation was found –as expected – on the catalyst surface:

4,394 ppm / 2,240 ppm for Unit 1 and 3,934 ppm / 1,958 ppm for Unit 2. Further enrichment with arsenic is likely, if the coal source is not change or secondary measures are not implemented. This will cause ongoing deactivation of the catalyst material.

Overall, the recent catalyst samples from Unit 1 showed higher amounts of catalyst poisons accumulated than the samples from Unit 2. This trend goes along with the determined catalytic performance of the different samples.

6 SCR Performance Forecast

This section describes the actual installed DeNOx potential and the actual effective DeNOx potential. The first is derived from the activity tests performed at E.ON's catalyst test facility. The effective potential, which is responsible for the DeNOx reaction in the SCR, is calculated from the installed potential, considering the effects of plugging, flue gas distribution and NH_3 to NOx distribution.

For the DeNOx potential calculation, the actual SCR operating data listed in Table 4, the catalyst design data listed in Table 5 and the bench reactor test results listed in Tables 6 & 7 were used.

Figures 1 to 6 in the appendix display the SCR Performance graphically; including hereby the influence and history of each single layer.

6.1 Installed Potential P_{gross} at Time of Sampling in October-2007

Under full boiler load conditions a flue gas flow rate of 708,000 m^3/h (STP, wet, act. O_2) is passed through the reactors. Considering a specific catalyst surface of 502 m^2/m^3 and an installed catalyst volume of 117 m^3 per layer, the area velocity AV was calculated as 12.1 m/h per layer. The **initial potential was 7.4** for the start-up installation with two layers. Regarding the measured catalyst activities for the installed layers after 14,808 (Unit 1) / 13,840 (Unit 2) service hours, the actual total installed DeNOx potential was **5.1 for Unit 1** and **5.8 for Unit 2**.

6.2 Operation Margin and Effective Potential at Time of Sampling in Oct-2007

Usually a proportion of the installed DeNOx potential cannot be applied because of clogged catalyst channels, eroded material, imbalanced gas flow, NH_3 / NOx maldistribution and other effects. These effects will reduce the actual installed potential. The degree of the actual operation margin for plugging required for any particular plant can only be determined by physical inspection of the SCR plant. Based on the chemical analysis, operating hours and E.ON's experience it is reasonable to consider 14 % plugging for the first layers and 9 % plugging for the second layers.

Usually the flue gas distribution is not equal throughout a layer, possibly caused by ash deposits on the catalyst modules, by burner imbalances or other effects. This will result in different distributions of temperature, flue gas flow and catalyst poisons. As temperature and the actual volume flow directly influence the activity, it also impacts the potential. Based on E.ON's experience a safety margin of 2 % is reasonable for the case of a typical flue gas distribution.

Since no information about the NH_3 to NOx distribution is available for either unit, we consider, according to our experience, a minimum operation margin of 5 % for the potential. The determination of the actual NH_3 to NOx distribution for each reactor by field testing would provide more detailed information about the type of distribution and possible degree of maldistribution. The minimizing effect on the potential of a NH_3/NOx maldistribution increases exponentially with the NOx removal efficiency, and it is additionally dependent on the type of distribution. For operating at high removal efficiencies a perfectly adjusted ammonia injection system is required. AIG tuning can increase the overall SCR reactor performance and can increase the catalyst lifetime.

Based on the above discussion, an overall operation margin of 19 % was used for the effective DeNOx potential calculation. Considering this operation margin the actual effective DeNOx potential P_{net} was determined to be 4.1 for Unit 1 and 4.8 for Unit 2 based on the recent samples. Considering all test points since 2005 the calculated average effective potential was 4.4 for Unit 1 and 4.5 for Unit 2. Ammonia in fly ash data provided by WKE indicated a slightly better performance for Unit 1 than for Unit 2, but the overall performance seems to be similar.

To keep the average ammonia slip lower than 2 ppm (90 % NOx removal efficiency and 301 ppm NOx inlet concentration), a minimum DeNOx potential of P_{min} = 3.6 is required.

Assuming a homogenous NH_3 to NOx distribution, a NOx removal efficiency of 90 % and a NOx inlet concentration of 301 ppm the ammonia slip was calculated to be below

0.3 ppm for both Units. Ammonia slip test after the last catalyst layer is a suitable tool to determine the exact slip value.

The combination of annual bench reactor catalyst testing, periodical ammonia slip testing and periodical NH_3 to NOx distribution measurements result in the most complete SCR performance evaluation.

6.3 SCR Performance over Time

Activity and **potential** of all layers over time are presented in Figures 1-4.

Figures 5 & 6 present the **NOx removal efficiency versus operating hours** for Henderson Station Units 1 & 2. Most power stations try to achieve higher NOx removal efficiencies than 90 %. The trends for an average ammonia slip of 1 and 2 ppm are shown. As already mentioned, at higher NOx removal efficiencies the impact of an inhomogeneous NH_3 to NOx distribution is significantly larger than for lower removal efficiencies. In contrast to the chart 'potential versus operating hours' (Figures 3 & 4) it is possible to include in Figures 5 & 6 adjusted operation margins for the different removal rates, if NOx distribution data are available. In the case, that the power plant operator intends to operate at NOx removal efficiencies above 90 %, it is advisable to decrease the limit for the allowed ammonia slip. Already slight changes in the DeNOx performance can have a large impact on the ammonia slip in this case. Therefore Figure 3 includes the 'NOx removal efficiency over time' curve for 1 ppm ammonia slip limit.

6.4 Catalyst Replacement Strategies

Based on the test results at E.ON's bench scale reactor since 2005, a long term catalyst replacement plan until 2023 was developed for both Henderson Units. All discussed scenarios assume that the unit operating regimes and the SCR operating conditions do not change to those prior 2007. As mentioned above, annual catalyst testing and periodical ammonia slip testing and NH_3 to NOx distribution testing are required to verify and update these long term strategies.

Following strategies were developed:

1. Three layer approach: A third layer will be installed at the next reasonable outage time.
2. Two layer outage based approach: Operation of the SCR reactors only with two layers of catalyst and all replacements are fit into the outage schedule.
3. Two layer approach: Another two layer SCR operation but based on the catalytic performance of the installed material.

Both Henderson units will be discussed together and differences will be pointed out for the individual scenarios.

6.4.1 Three Layer Approach

Figures 7 and 8 in the appendix display the replacement strategies for both units. Based on the deactivation behavior determined to date, Unit 1 would have to invest in three catalyst layers until 2023 and Unit 2 probably in two layers. For these scenarios it does not matter, if new material is purchased as reload for the upper two layers over time or if the used material is regenerated. Typically, E.ON made the experience that the deactivation of regenerated material is very similar to the original one.

Additionally, based on the actual performance of Unit 2, it was anticipated that the third layer would only be installed during the 2010 outage. A more conservative approach would be installing this layer in 2008; as a result three layers instead of two would have to be purchased until 2023 (similar to Unit 1).

Catalyst material with a little lower initial activity (K_0 > 40 m/h) was considered compared to the start-up installation (K_0 44.6m/h). From the NOx removal point of view, the higher the initial potential the longer the will be the operation time of this layer. But from the perspective of SO_3 emission, high activities are connected to moderate SO_2 to SO_3 conversion rates. Lowering the initial activity slightly can have a significant benefit towards a lower SO_2 to SO_3 conversion rates. To decide for the correct material for a catalyst reload, both factors have to be considered. Also, the position of the layer in the SCR has to be taken into account. Ammonia in the flue gas reduces the capability of the catalyst to convert SO_2 to SO_3; the lowest layer in the SCR sees the lowest amount of ammonia. Thus, it is advisable to choose a low SO_2 to SO_3 converting material for a third layer installation, even if the NOx removal performance is a little bit less.

The SO_3 amount produced by the actual installed two catalyst layers was expected to be between 10 and 17 ppm. A third layer would cause in a worst case about 10 ppm additional SO_3 emission; this is based on the actual conversion rate of the installed material. Choosing a low SO_2 to SO_3 converting material, the SO_3 amount produced by the third layer might be 5 ppm or lower. Considering a typical boiler conversion of 1 % the total SO_3 emission would be 40 to 47 ppm for two layers and 47 to 54 ppm for three installed layers. Part of the SO_3 will be removed by the air heaters, ESP and FGD, but only actual testing at different locations of the flue gas path can determine the exact amount of SO_3 emission.

6.4.2 Two Layer Approach Outage Based

Figures 9 and 10 show this replacement strategy for Unit 1 and 2. For a biannual catalyst replacement and two layer operation approach, catalyst material with an initial activity of 45 m/h or higher is required. Unit 2 shows a little lower average deactivation than Unit 1, therefore it might be possible to skip the 2008 outage for any catalyst replacements and start only with 2010 for the biannual reload strategy. Until 2023, nine (9) reloads would be required for Unit 1 and seven (7) reloads for Unit 2. Again, regeneration should be considered as an alternative to new material purchases.

6.4.3 Two Layer Approach Catalyst Based

In the case of Unit 1, it seems that the required reloads fit very well into the outage schedule; no additional scenario seems to be reasonable. Based on the catalyst test results, Unit 2 showed a better performance in average over time. Therefore, some outages might be postponed for some months, see Figure11 in the annex. Over the time period until 2023, it would be possible to reduce the required reloads from seven (outage based) to six layers (catalyst based).

6.4.4 Summary and Recommendations

Typically, adding the third layer is the most cost efficient way for catalyst management strategies, because each individual layer is operated for a longer time than in a two layer approach, so more of the catalytic potential is used. Therefore, we strongly *recommend an evaluation of the consequences of an increased* SO_3 emission by up to 10 ppm (prior ESP and FGD). However, utilizing a low SO_2 to SO_3 converting material, the additional SO_3 emission caused by the third layer might be reduced to less than 5 ppm. This would consequently come along with a little lower NOx removal performance (requiring the addition of one more layer until 2023 per unit), but would *still require less catalyst reloads than the two layer approaches.* Following catalyst replacements could also be made with a low converting catalyst time that eventually the same SO_3 emission is reached as with the actual installed two layers.

However, the difference in performance and deactivation found in the catalyst test at the bench reactor should be verified by ammonia slip testing. Tuning of the AIG by for example E.ON's MARA team (mobile automated flue gas analyzer) could improve the overall SCR performance and prevent locally high ammonia slip. The ammonia in fly ash data indicate a significant imbalance between the different hoppers, the reason should be traced down since it could be also a source having a negative impact on the SCR reactor performance.

Strategy	Unit	Required Catalyst Layers until 2023	Expected total SO_3 production (boiler & SCR) [b]	Required K_0 [m/h]	Required K_E [m/h] [d]
1	1	3	up to 55 ppm [c]	> 40.0	> 23.0 after 45,000 h
	2	2 (3) [a]			
2	1	9	up to 45 ppm	> 45.0	> 27.0 after 35,000h
	2	7			
3	2	6			

Table 3: Summary of Reload Strategies for HMPL 1 & 2

Notes: [a] **three layers will be required if the third layer is added in 2008**
[b] **the SO_3 emission at the stack will be lower due to SO_3 removal in air heater, ESP and FGD**
[c] **utilizing low SO_2 to SO_3 converting material could lower the total SO_3 production**
[d] **if catalyst vendors guarantee only lower operating hours, higher end activity (K_E) values have to be requested**

HMPL might consider regeneration of catalyst material as a cost effective alternative to purchasing new material. E.ON Engineering Corp. will gladly assist HMPL in the preparation of RFQs and in evaluation of different bids. We also recommend discussing the presented reload strategies in person for better understanding of required details and additional options.

7 Annex

8 Literature

1. VGB Guideline for the Testing of DeNOx Catalytic Converters, VGB-R 302He, 2nd Revised Version, Published by VGB Kraftwerkstechnik, Klinkestrasse 27-31, 45136 Essen, Germany
2. Catalyst Test Report, Henderson Station Unit 1&2 2005, E.ON Engineering Corp.
3. Catalyst Test Report, Henderson Station Unit 1&2 2006, E.ON Engineering Corp.

8.1 Index of Tables and Figures

8.2 Tables and Figures

Table 4: SCR Design and Operation Data

SCR Data				
Station	Henderson		Unit 1	Unit 2
Capacity	MW_{net}		154	161
Fuel	-		coal	
No. of reactors	-		1	1
Date of SCR start-up	-		Nov.03	Apr. 04
SCR Operating Hours	h		14,808	13,840
Flue Gas Data		***design***	***actual***	
Flue Gas Flow Rate per Unit	acfm	960,000	960,000	
	m^3/h (STP, wet, act. O_2)	662,934	708,001	
Flue Gas Temperature	°F	750	673	
	°C	399	356	
NO_x inlet	ppmvd (STP, dry, act. O_2)	301	301	
SO_2 inlet	ppmvd (STP, dry, act. O_2)	3,300	3,300	
SO_3 inlet*	ppmvd (STP, dry, act. O_2)	39	39	
O_2	% by vol (dry)	3.0	3.0	
H_2O	% by vol	8.0	8.0	

** not injected for bench reactor test*

Table 5: Catalyst Design Data

Catalyst Data					
			Layer 1	Layer 2	Layer 3
Date of Sampling	-	**Unit 1**	Oct-07	Oct-07	
Date of Installation	-		Nov-03	Nov-03	empty
Layer Operating Hours	h		14,808	14,808	
Date of Sampling	-	**Unit 2**	Oct-07	Oct-07	
Date of Installation	-		Apr-04	Apr-04	empty
Layer Operating Hours	h		13,840	13,840	
Catalyst Manufacturer	-		Cormetech	Cormetech	
Catalyst Structure	-		honeycomb	honeycomb	
Catalyst Volume per Layer V_C	m^3		117	117	
No. of Modules per Layer	-		60	60	
Specific Surface Area A_P	m^2/m^3		502	502	
Void Fraction	%		74	74	
Pitch	mm		7.1	7.1	
Length	mm		1,209	1,209	
No. of honeycombs per module	-		72	72	

Table 6: Bench Reactor Test Results for Henderson Unit 1

Test Results of Catalyst Test Element		**Unit 1**		
		Layer 1	Layer 2	New
Activity Constant K	m/h	29.8	31.4	44.6
NOx Removal Efficiency (η)	-	0.913	0.923	0.973
SO_2 Conversion Coefficient K_{SO2}	10^{-2} m/h	3.1	3.0	3.3
Pressure Loss Δp	mbar	1.7	1.7	1.6

Test Element Dimensions and Specific Test Conditions				
Length	mm	1207	1207	1,205
Width	mm	129.1	129.5	129.2
No. of channels (plugged ch.)	-	324 (20)	324 (15)	324 (0)
Flue Gas Flow (wet, act. O_2)	Nm^3/h	118	116	120
Flue Gas Temperature	°F	674	673	673
α (NH_3 to NOx ratio for activity test)	-	1.02	1.00	1.01
Area Velocity	m/h	12.2	12.2	12.3
Linear Velocity (in channels)	act. m/s	6.01	6.02	6.06

Table 7: Bench Reactor Test Results for Henderson Unit 2

Test Results of Catalyst Test Element		**Unit 2**		
		Layer 1	Layer 2	New
Activity Constant K	m/h	34.7	35.8	44.6
NOx Removal Efficiency (η)	-	0.944	0.947	0.973
SO_2 Conversion Coefficient K_{SO2}	10^{-2} m/h	3.8	3.3	3.3
Pressure Loss Δp	mbar	1.6	1.6	1.6

Test Element Dimensions and Specific Test Conditions				
Length	mm	1206	1206	1,205
Width	mm	129.4	129.3	129.2
No. of channels (plugged ch.)	-	324 (11)	324 (11)	324 (0)
Flue Gas Flow (wet, act. O_2)	Nm^3/h	116	117	120
Flue Gas Temperature	°F	674	673	673
α (NH_3 to NOx ratio for activity test)	-	1.01	1.02	1.01
Area Velocity	m/h	12.1	12.2	12.3
Linear Velocity (in channels)	act. m/s	5.82	5.98	6.06

Table 8: Catalyst Layer Performance Data

Henderson Unit 1 (at time of sampling in Oct-2007)

		Layer 1	Layer 2	Layer 3	New
Installed DeNOx Potential K/AV_{SCR}	-	2.5	2.6	empty	3.7
SO_2 Conversion Rate K_{SO2}/AV_{SCR}*	%	0.26	0.25		0.27
Pressure Loss Δp *		1.7	1.7		1.6

Henderson Unit 2 (at time of sampling in Oct-2007)

		Layer 1	Layer 2	Layer 3	New
Installed DeNOx Potential K/AV_{SCR}	-	2.9	3.0	empty	3.7
SO_2 Conversion Rate K_{SO2}/AV_{SCR}*	%	0.32	0.27		0.27
Pressure Loss Δp *		1.6	1.6		1.6

SCR Reactor Specific Conditions					
Layer Area Velocity AV_{SCR}	m/h	12.1	12.1		12.1
Space Velocity	1/h	6,051	6,051		6,051
Linear Velocity (in channels)	act. m/s	6.3	6.3		6.3

* results for installed, clean layer in SCR reactor

Table 9: SCR Performance Data for Henderson Unit 1, Sampling Oct-2007

Henderson Unit 1 (at time of sampling in Oct-2007)

		Layer 1	Layer 2	Layer 3	**Total**
Installed DeNOx Potential P_{Gross}	-	2.5	2.6	empty	**5.1**
Operation Margins					
Pluggage	%	14	9		12
Effect of Flow Distribution	%	2	2		2
Effect of NH_3 to NOx Distribution	%	5	5		5
Effective DeNOx Potential P_{net}	-	2.0	2.2		**4.1**
Minimum Potential P_{min} (90% NOx Removal Efficiency, 2ppm slip, act. NOx inlet)					**3.6**

Table 10: SCR Performance Data for Henderson Unit 2, Sampling Oct-2007

Henderson Unit 2 (at time of sampling in Oct-2007)

		Layer 1	Layer 2	Layer 3	**Total**
Installed DeNOx Potential P_{Gross}	-	2.9	3.0	empty	**5.8**
Operation Margins					
Pluggage	%	14	9		12
Effect of Flow Distribution	%	2	2		2
Effect of NH_3 to NOx Distribution	%	5	5		5
Effective DeNOx Potential P_{net}	-	2.3	2.5		**4.8**
Minimum Potential P_{min} (90% NOx Removal Efficiency, 2ppm slip, act. NOx inlet)					**3.6**

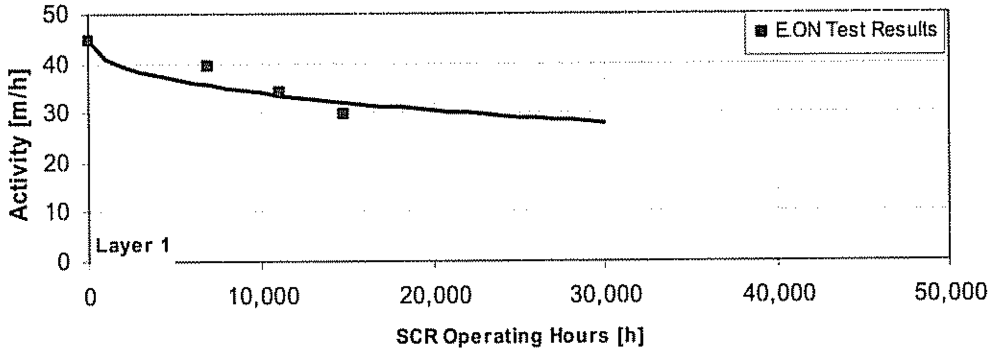
Table 11: Chemical Composition of the Catalyst Bulk Material (XRF Analysis)

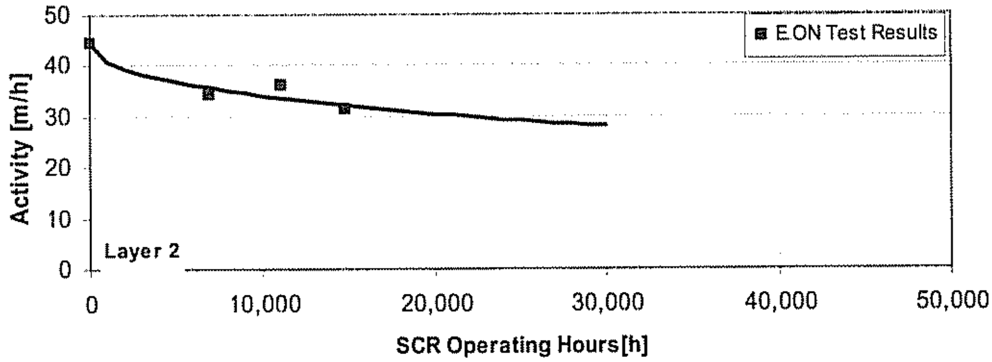
		Unit 1				Unit 2			
		Layer 1		Layer 2		Layer 1		Layer 2	
	New	in	out	in	out	in	out	in	out
$\%SiO_2$	4.3	4.7	4.5	4.7	4.9	4.7	4.6	4.7	4.6
$\%Al_2O_3$	0.59	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7
$\% Fe_2O_3$	0.05	0.09	0.06	0.09	0.07	0.07	0.06	0.08	0.06
$\% TiO_2$	82.5	80.8	81.4	80.7	80.8	81.2	81.4	81.1	81.5
% CaO	1.2	1.4	1.4	1.4	1.4	1.1	1.1	1.1	1.1
% MgO	0.15	0.11	0.09	0.10	0.08	0.15	0.15	0.16	0.14
$\% Na_2O$	0.02	0.14	0.13	0.16	0.13	0.08	0.08	0.11	0.07
$\% K_2O$	0.02	0.14	0.11	0.18	0.12	0.11	0.09	0.13	0.08
$\% SO_3$	1.3	1.2	1.2	1.4	1.4	1.2	1.2	1.1	1.2
$\% P_2O_5$	0.03	0.03	0.02	0.03	0.02	0.05	0.05	0.05	0.04
$\% V_2O_5$	0.81	0.61	0.57	0.60	0.58	0.67	0.64	0.67	0.66
$\% WO_3$	8.8	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.3
$\% MoO_3$	0.04	0.30	0.23	0.27	0.21	0.32	0.28	0.32	0.24
As (ppm)	188.0	3,493	2,363	3,282	1,367	2,551	2,076	3,029	1,117

Table 12: Chemical Composition of the Catalyst Surface (XRF Analysis)

		Unit 1				Unit 2			
		Layer 1		Layer 2		Layer 1		Layer 2	
	New	in	out	in	out	in	out	in	out
$\%SiO_2$	2.5	12.0	5.2	11.4	4.9	7.8	4.1	7.9	4.2
$\%Al_2O_3$	0.27	2.4	1.3	1.8	1.0	1.5	0.9	1.6	0.9
$\% Fe_2O_3$	0.15	0.66	0.33	0.45	0.38	0.47	0.22	0.46	0.22
$\% TiO_2$	83.6	66.6	78.3	69.4	79.0	73.7	80.1	73.8	80.3
% CaO	0.88	1.8	1.4	1.8	1.4	1.3	1.1	1.3	1.1
% MgO	<0.10	0.11	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10
$\% Na_2O$	<0.10	0.55	0.26	0.44	0.20	0.21	0.12	0.24	0.11
$\% K_2O$	<0.10	0.34	0.19	0.20	0.15	0.22	0.10	0.20	0.12
$\% SO_3$	1.7	6.7	2.6	5.4	2.7	4.7	2.3	4.3	2.1
$\% P_2O_5$	0.07	0.18	<0.10	<0.10	<0.10	0.20	<0.10	0.16	<0.10
$\% V_2O_5$	0.94	0.83	0.83	0.85	0.81	0.96	0.95	0.93	0.97
$\% WO_3$	9.6	6.7	8.5	7.0	8.7	7.8	9.0	7.9	9.2
$\% MoO_3$	<0.10	0.32	0.28	0.30	0.26	0.34	0.35	0.33	0.33
As (ppm)	<500	4,400	4,330	4,320	1,720	3,910	3,940	4,350	1,360

Figure 1: Activity over Time, Henderson Unit 1





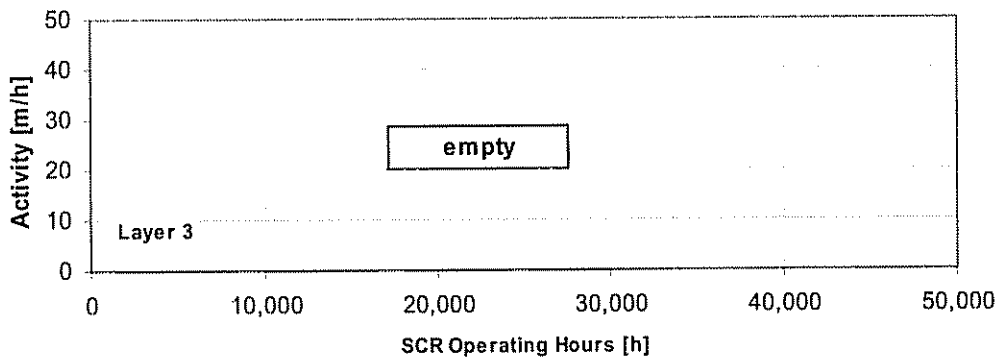
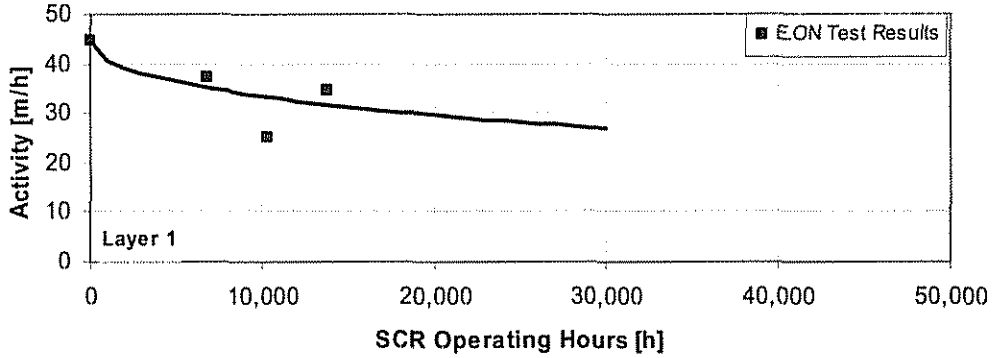
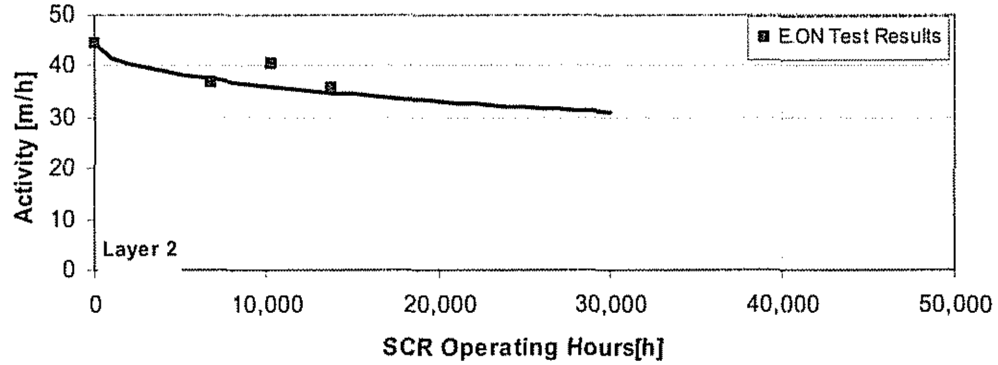


Figure 2: Activity over Time, Henderson Unit 2





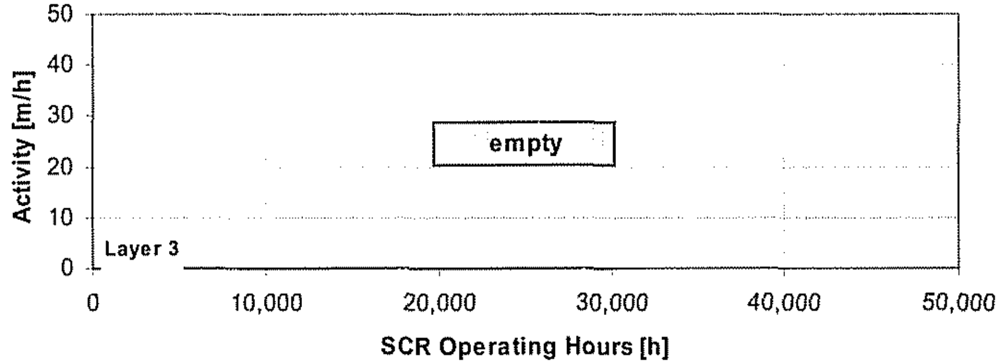


Figure 3: DeNOx Potential over Time, Henderson Unit 1

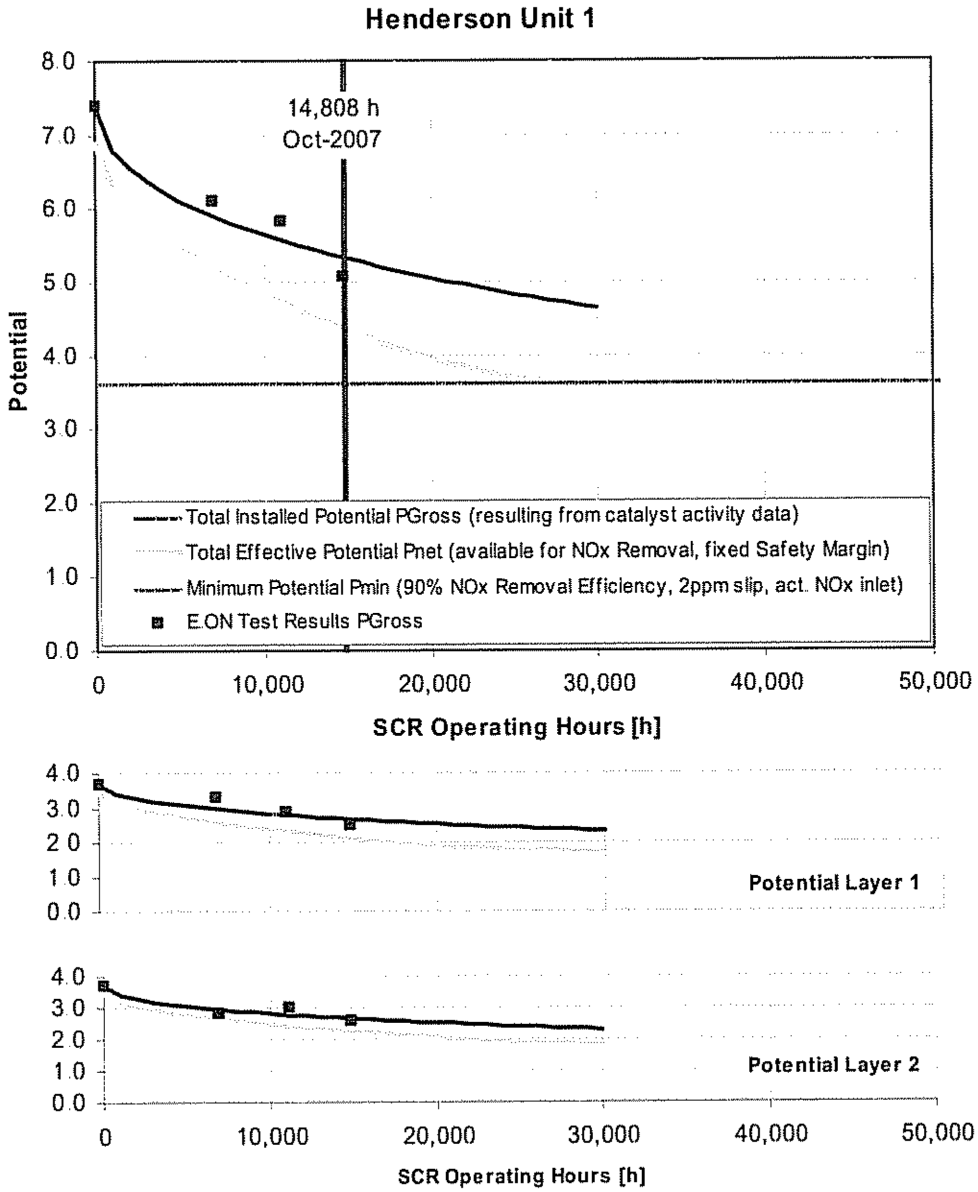


Figure 4: DeNOx Potential over Time, Henderson Unit 2

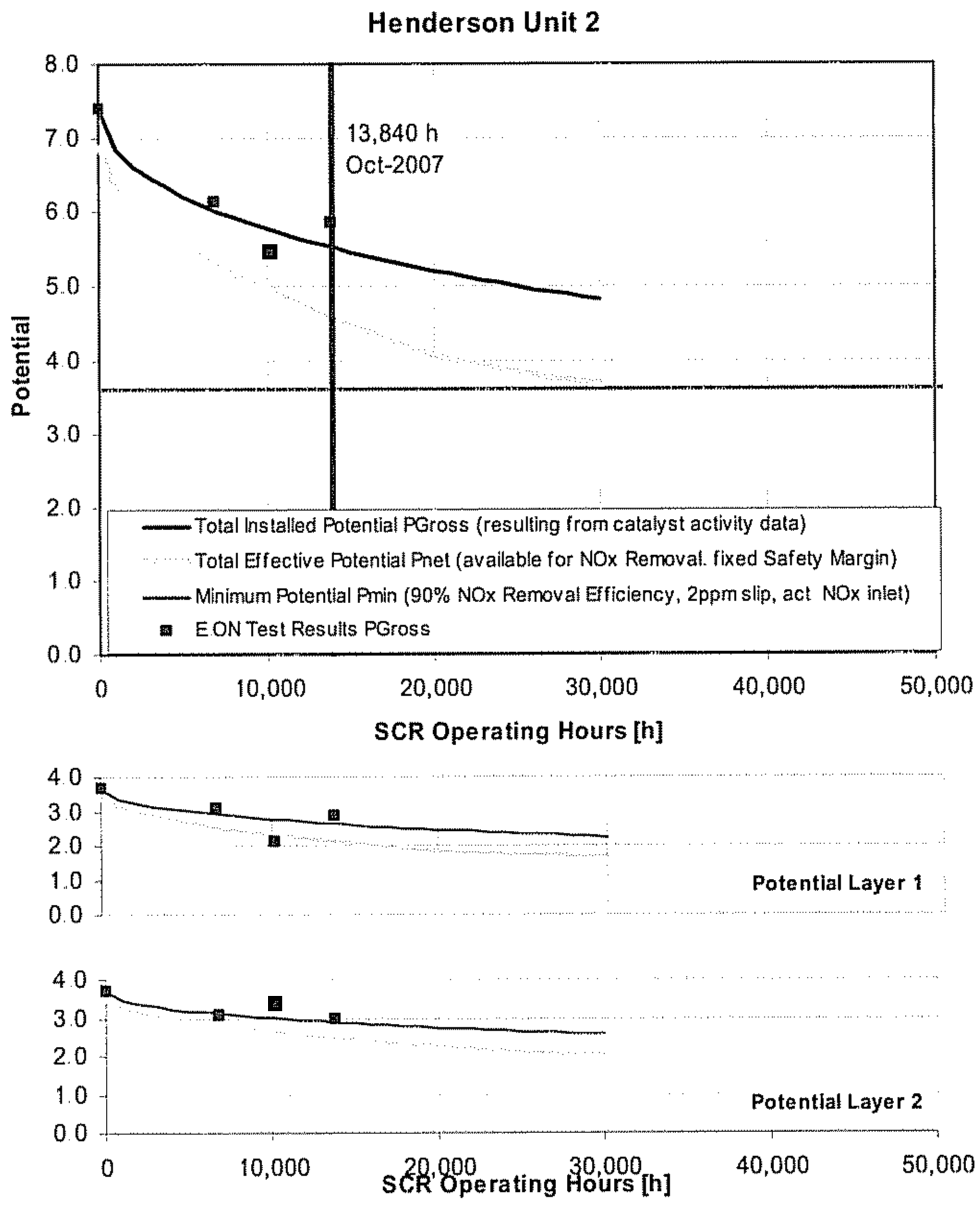


Figure 5: NOx Removal Efficiency over Time, Henderson Unit 1

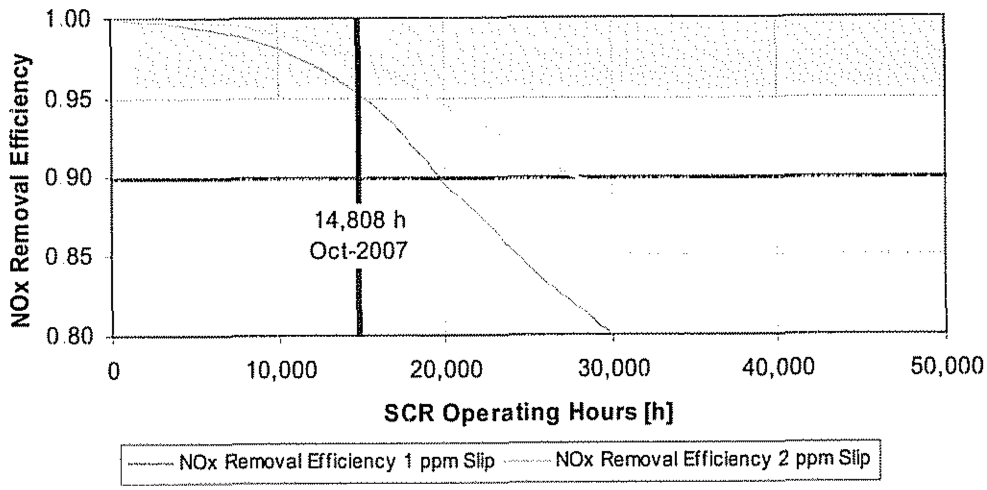
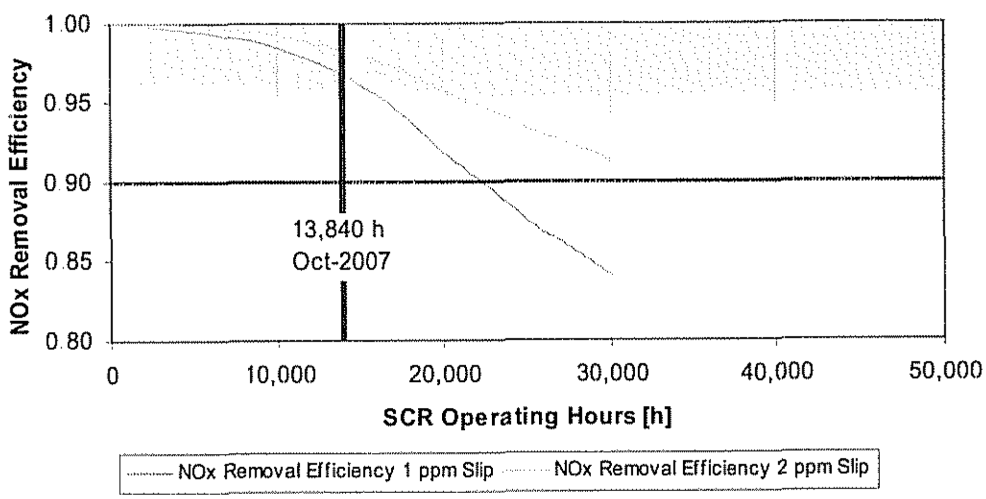


Figure 6: NOx Removal Efficiency over Time, Henderson Unit 2



* Operating SCR reactors above 95 % NOx removal efficiency requires perfectly adjusted DeNOx systems

Figure 7: Henderson Unit 1, Catalyst Management Strategy 1 – Three Layer Approach

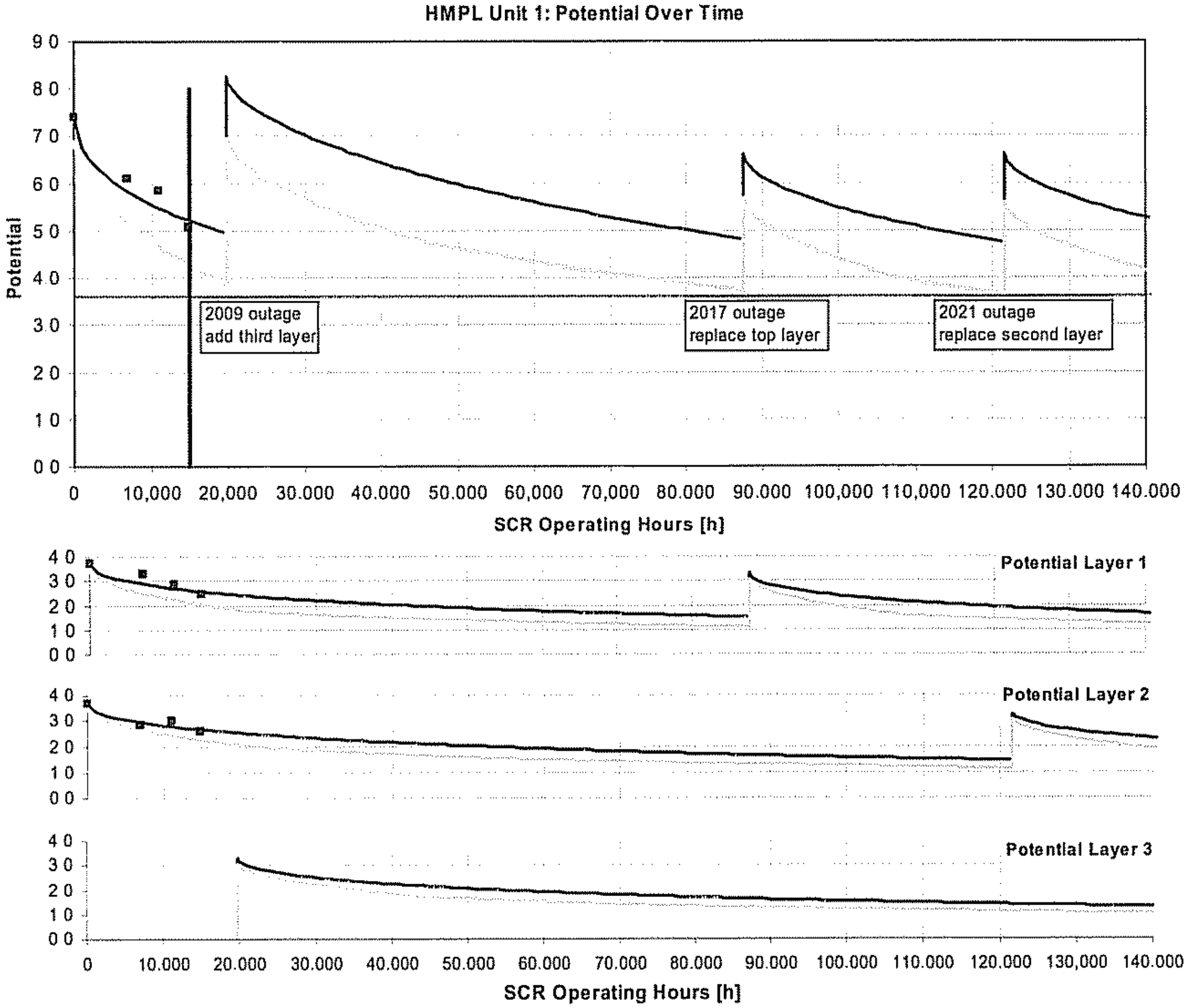


Figure 8: Henderson Unit 2, Catalyst Management Strategy 1 – Three Layer Approach

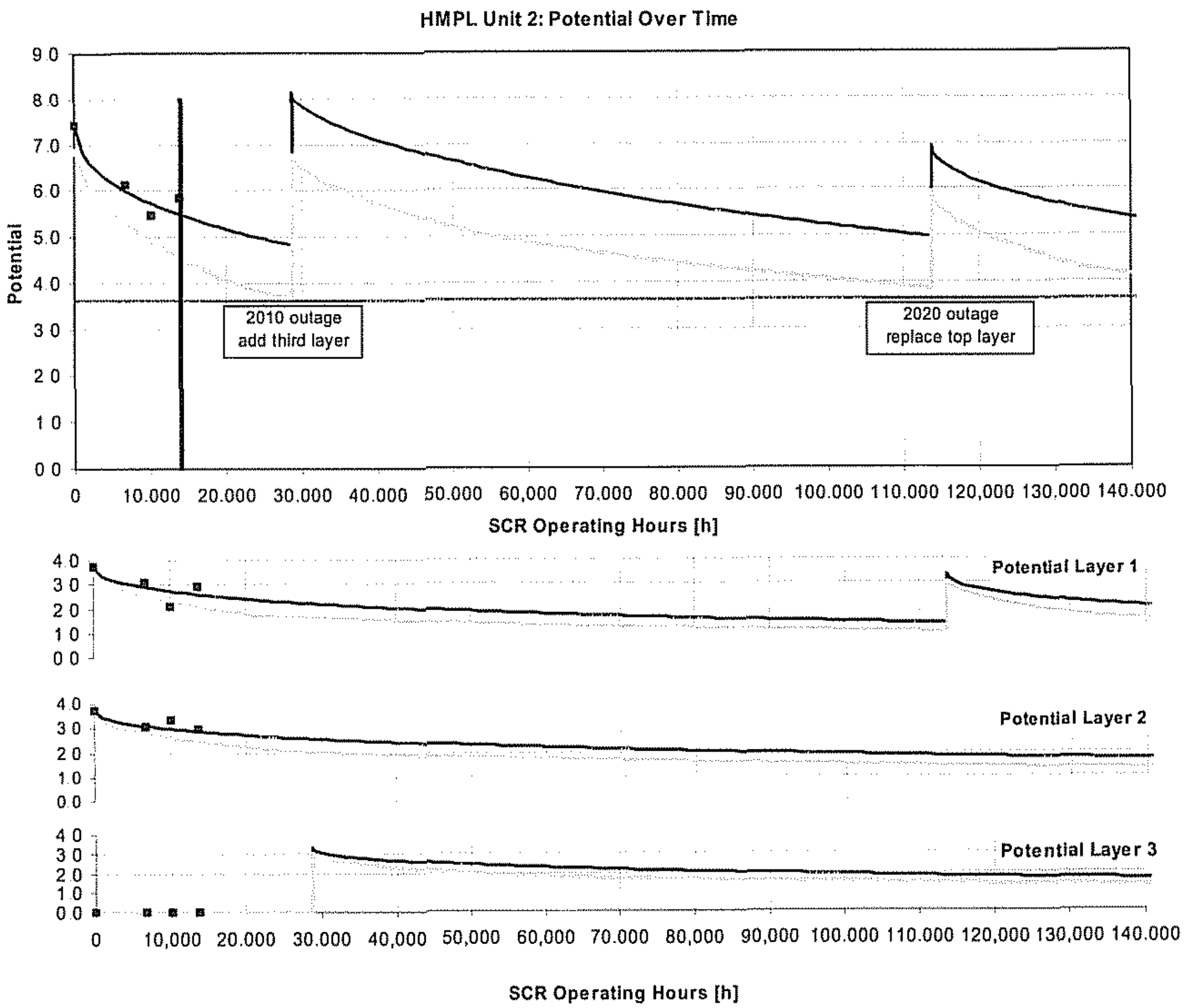


Figure 9: Henderson Unit 1, Catalyst Management Strategy 2 – Two Layer Approach Outage Based

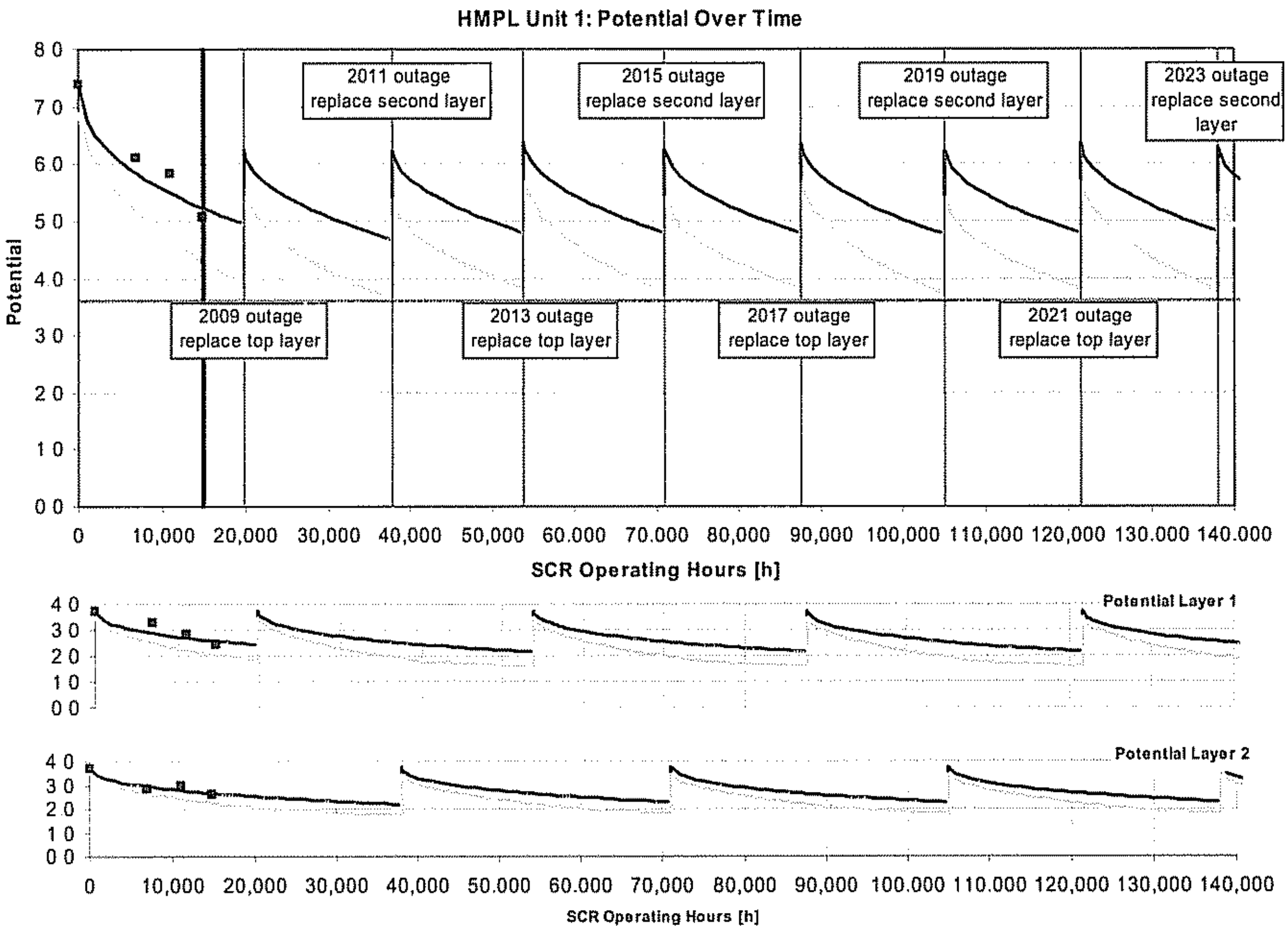


Figure 10: Henderson Unit 2, Catalyst Management Strategy 2 – Two Layer Approach Outage Based

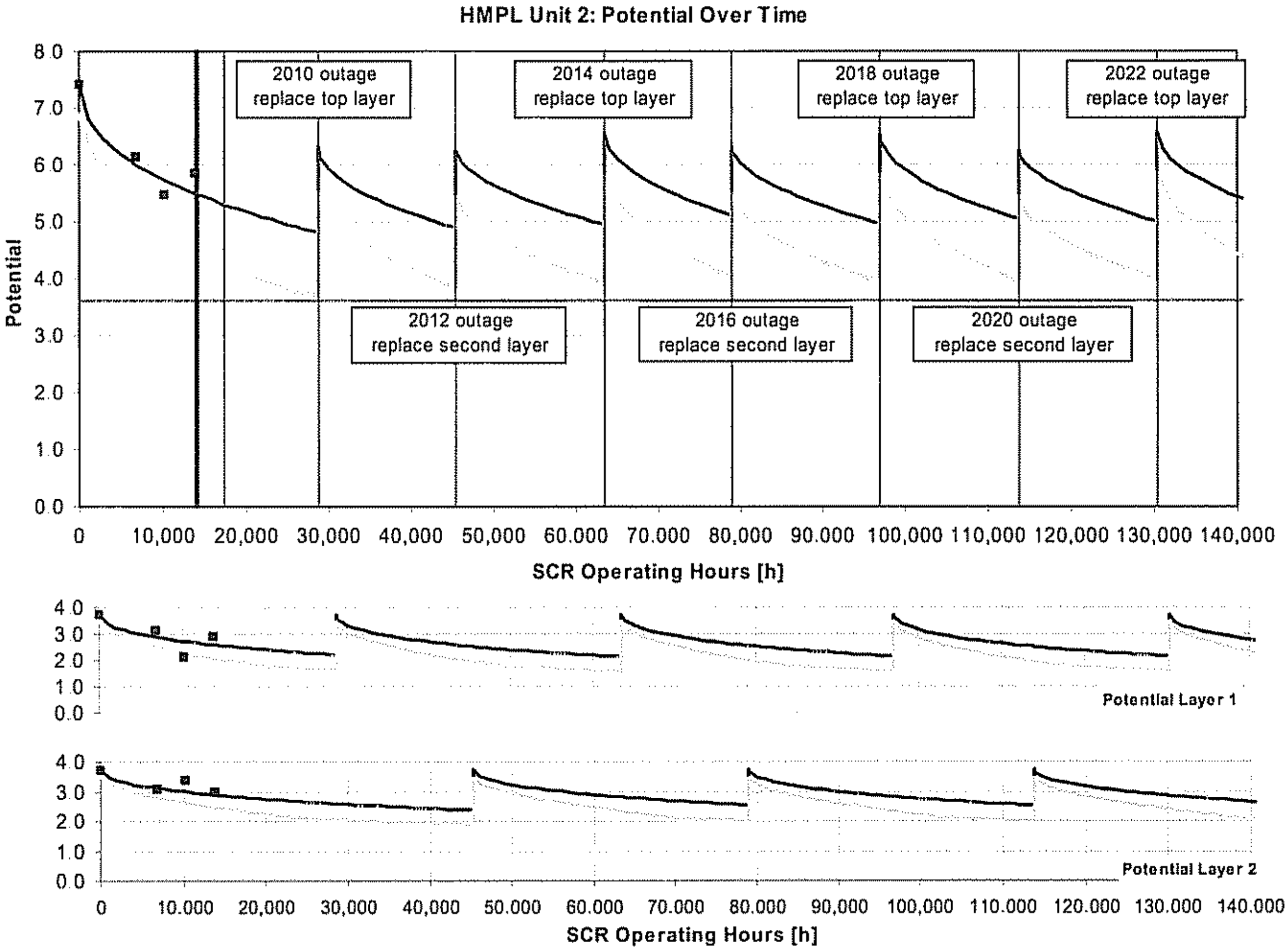
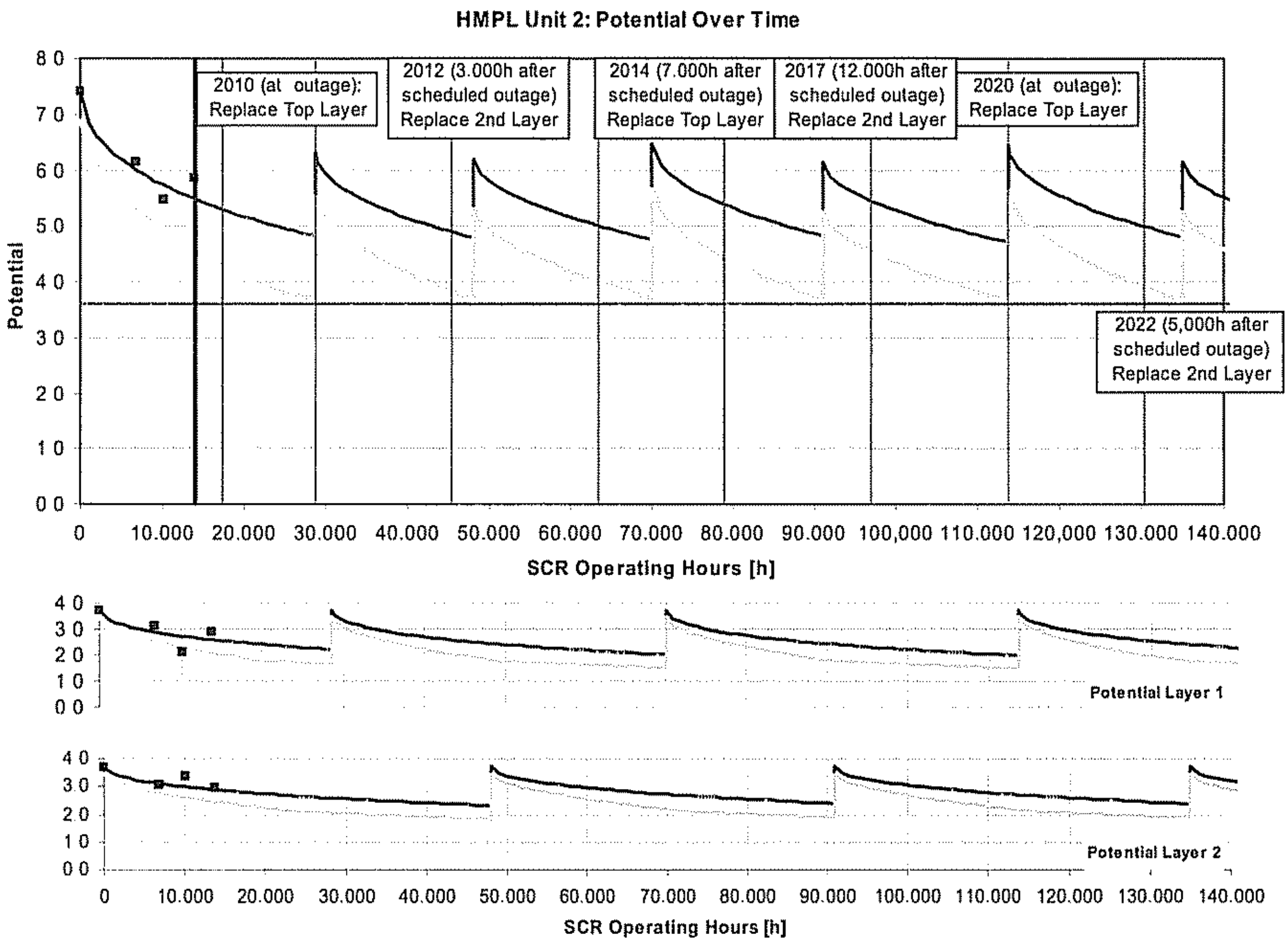


Figure 11: Henderson Unit 2, Catalyst Management Strategy 3 – Two Layer Approach Catalyst Based



ATTACHMENT 3

BURNS AND MCDONNELL REPORT

Burns & McDonnell

FAX MESSAGE

Date 8/4/97 Time ______ AM PM

To: Jim McIllwain FAX No. (502) 827-9336

Representing: BREC Info. Acct. ______

From: Bill Smith Number of Pages (including this cover sheet): 27

Project Name: BREC Project No. 97-274-3-001 Contract No. ______

4800 Bldg. S2 — 24-Hour Automatic FAX No. 816 822-3415 — FAX Operator: Voice 816 333-4375, ext. 2479
4600 Bldg 3N — 24-Hour Automatic FAX No. 816 822-3414 — FAX Operator: Voice 816 333-4375, ext. 2337
4800 Bldg N1 — 24-Hour Automatic FAX No. 816 333-3690 — FAX Operator: Voice 816 333-4375, ext. 2415

Jim -

Finally!

1. This is my last day here for a while, so give me your comments ASAP.

2. Do you want any recommendations in here? I think we said no but not sure.

Signed Bill Operator ______

TEL: 816 333-4375 TWX: 910 771-3059
U.S. Mail Address: P.O. Box 419173, Kansas City, Missouri 64141-6173
Parcel and Express Package Address: 4800 East 63rd Street, Kansas City, Missouri 64130

060692 Form G-9

Report Outline
Big Rivers Electric Corporation
Review of DB-Riley CCV Low NO_x Burner Performance
at HMP&L Station Two Unit 2

Burns + McDonnell

I. Investigation
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   B. General Comments
II. Data & Data Reduction
   A. Test Data Summary
   B. Control Board Data Sheets
   C. Furnace Gas Temperature Profiles
   D. Velocity Calculations
   E. Coal Analyses
   F. Ash Analyses
III. Performance & Operability
   A. NO_x
   B. Opacity
   C. LOI
   D. Steam Temperature
   E. High Load Stability
   F. O_2 Imbalance
   G. Slagging
   H. Side Wall Flame Impingement
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   K. Sensitivity to Fuel and Load Changes, and Adjustment
IV. Evaluation
   A. Secondary Air Velocity
   B. Primary Air Velocity
   C. SA/PA Velocity Ratio
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   E. Controls
V. Conclusions
   A. Performance
   B. Performance Testing

Draft Report
Big Rivers Electric Corporation
Review of DB-Riley CCV Low NO_x Burner Performance
at HMP&L Station Two Unit 2

I. **Investigation:**

A. On Monday July 14, 1997 through Thursday July 17, 1997 Burns and McDonnell visited HMP&L Station Two Units 1 and 2 at the request of Big Rivers. Bill Smith and Bob Kaltenbach of Burns and McDonnell spent Tuesday, Wednesday and Thursday walking down both units while observing full load operation under a variety of burner adjustments and fuels. The purpose of the visit was to assess and report on the performance of the units with the installed low NO_x burners supplied by DB-Riley.

A letter of preliminary findings was issued to Big Rivers on Thursday, July 24, 1997.

B. <u>General Comments</u>: The investigation was conducted over a 3 day period of time. Both units were made available for observation at the same time firing the same fuel and operating at the same load. DB Riley apparently left BREC with a set of operating settings for the air registers, burners and O_2 for each unit. We were able to observe the performance of each unit while adjusted to those same DBR settings, and again on the same day with adjustments chosen by BREC for improved operability.

The units were firing an unknown blend off of the Ready Pile on the first day of testing, straight Lanham coal on the second day and straight Westwood coal on the third day. Unfortunately, Unit 2 developed a tube leak on the third day and could not be observed while firing Westwood coal.

Burns & McDonnell brought an infra-red pyrometer to the site for the purpose of determining relative furnace gas temperatures and temperature profiles in both units at varying operational settings. The infra-red pyrometer provides an average only, and does not identify absolutely accurate temperatures. The emissivity setting remained at .88 for all tests, which is a compromise of convenience. The data is useful for comparison, as intended, but not for determining accurate temperature at a specific point location.

Each unit walkdown included written comments regarding furnace observations, and photographs taken through the observation door openings. The comments are included in this report. The photographs are also included in instances where the photograph provides a clear image. Clear photographs of fire can be difficult to obtain.

II. **Data and Data Reduction:**

A. Test Data Summary: The test data for each unit is summarized in a table in this report. The sheet records control room data, burner settings, coal analyses and ash analyses.

B. Control Board Data Sheets: The control board data sheets are included in this report. The sheets record control board data pertinent to the operation and performance of the units. Alarm logs were not retrieved.

C. Furnace Gas Temperature Profiles: The infra-red pyrometer data taken through the furnace observation doors is included in this report, and graphed in order to compare H1 with H2 and to compare the two operating methods.

D. Velocity Calculations: The DB-Riley burner design data sheet and the CCV burner drawings were reviewed to calculate secondary air velocity and primary air velocity exiting each burner. The calculation results are shown in the calculation data sheet. A burner throat diameter of 47-inches was used rather than 49-inches. After reviewing the burner throat design we believe that the short expansion from 47 to 49-inches is too abrupt to effectively reduce velocity within the burner throat.

E. Coal Analyses: One coal sample was retrieved by the BREC operating staff during each test. The sample was analyzed to determine proximate analysis, ultimate analysis, grindability, heating value, ash fusion temperatures (8 point), and ash minerals.

F. Ash Analyses: One set of eight hopper ash samples were retrieved by the BREC operating staff during each test. Each sample was heated to determine the moisture fraction, and then heated to determine the combustibles fraction.

III. **Performance and Operability:**

A. NO_X: NO_X reduction was the primary purpose for installing the low NO_X burners. The performance of both units has improved considerably over the operation observed in April of 1996. The two identical units behave differently from each other, but both seemed to be able to achieve a NO_X performance of approximately .50 lb/10^6 Btu at 161 Mw during the tests. NO_X performance during the tests varied from .418 lb/10^6Btu to .493 lb/10^6Btu. Full load on Unit 2 however is 172 Mw. Plant records indicate NO_X performance is very inconsistent, and can vary from under .50 lb/10^6Btu to as high as about .55 lb/10^6Btu.

NO_X on H2 varied from .418 lb/10^6Btu to as high as .478 lb/10^6Btu. We would assume that the DBR settings were determined either to maximize NO_X reduction or to optimize the inevitable tradeoff that occurs between NO_X, LOI, steam temperature and unit operability. The BREC settings were chosen primarily to improve the operability of the unit. However, the performance of H2 improved in nearly every area, including NO_x, steam temperature, and operability when using the BREC settings. LOI changed very little, increasing on one fuel and decreasing on another fuel with the BREC settings.

NO_x performance of H1 scarcely changed from about .487 lb/10^6Btu as fuel or adjustments were changed.

B. <u>Opacity</u>: Opacity is still an issue, especially on H2. The H2 opacity is consistently higher than H1, and spikes frequently. The control room instrumentation does not seem to indicate a reason for the opacity spikes. Opacity was affected most by the fuel selection, and little by the burner adjustments.

Average opacity of both units exceeded the 20% limit on 6 of the 10 tests.

C. <u>LOI</u>: LOI reports indicated a spread of 5.70% to 10.12% on H1 and 6.66% to 7.92% on H2. Graphically the 10.12% test on H1 appears to be a bad test. Without that test the data all falls in line, indicating a variation of 5.70% to 8.83% on H1. Assuming the samples are representative, LOI seems to be under control at 161 Mw.

D. <u>Steam Temperature</u>: Units H1 and H2 were designed to control reheat temperature via excess air. There are no backpass dampers, gas recirculation fans or burner tilts. As such, operation at low O_2 can significantly impact reheat and superheat temperatures. During the H2 test with DB-Riley settings we witnessed a period of time when reheat temperature was low, spray valves were not open, but reheat tube metal temperatures were in alarm. Assuming the alarms are legitimate, this is at least an indication of very uneven firing and uneven heat release within the furnace.

Both units appear to have a problem making superheat and reheat steam temperature. While H2 usually comes close to 1000°F, neither unit used any desuperheater spray during any of the 10 tests. Steam temperature was as low as 938°F for H1 reheat, and 983°F for H2 reheat.

E. <u>High Load Stability</u>: Unit stability and operability are the primary reasons for the BREC burner and air register settings. On the Lanham coal in particular, the units were very unstable with the DBR settings. At one point the operators had to drop load and go to manual in order to recover from unit instability. Burners B3 and B4 both became detached on Lanham and Westwood coals with either set of adjustments.

F. O_2 Imbalance: There is an indicated imbalance in economizer exit O_2 which is abnormal and detrimental to performance of the unit, and especially detrimental to NO_X reduction efforts. We believe the O_2 imbalance is real, and not just an instrument error. The unbalance was apparent in April of 1996, and is still present today. These unit have pressurized furnaces, so inleakage should not be a consideration.

G. Slagging: Unit slagging persists. The front (target) wall usually has 1-inch to 2-inches of tacky plastic slag, often with char particles burning off on and around the slag. Burner eyebrows have decreased in size. There is still a significant amount of slag in the radiant superheater pendants, however.

H. Side Wall Flame Impingement: Side wall flame impingement is occurring for up to 40% of the length of the sidewall. While this is rather subjective, it certainly has to be detrimental to the life of the tubing.

I. Front Wall Flame Impingement: There was no front (target) wall flame impingement during any of the 10 tests.

J. Firebox Flame Description: This report includes descriptive notes documenting observations made through the furnace inspection doors during each inspection. In general, both units were full of flame from the burner level all the way up to and through the radiant superheater. The flame and the high temperatures in the upper furnace are obvious. Temperatures in the upper furnace are also often uneven.

Very dense flame is also rolling up and off of the upper end of the slope. This is true in both furnaces.

The flame impingement on both side walls is very heavy for the first 40% of the length of the wall, and then nearly non-existent. There is minimal front wall flame impingement.

The burner flames are very turbulent, as if they were not from low NO_X burners. Only very seldom was there a visible coal skirt at the base of the flame. Burners B3 and B4 very often refused to ignite for about 4-feet. This was always correctable by closing down on the air register vanes.

In summary, the entire furnace is full of flame, with minimal target wall impingement and about 40% side wall impingement The flame continues, concentrates along the rear wall slope, and then reaches the pendants. Burner flame appears hot and turbulent, but often detaches on burners B3 and B4.

K. <u>Sensitivity to Fuel and Load Changes, and Adjustment</u>: Both units seem to be very sensitive to all adjustments. Changing excess O_2, air register hood position, or air register vane position often have significant affects on unit performance. The useful vane position adjustment range is between 30 degrees and 35 degrees. The useful hood position adjustment at full load is 59 percent to 80 percent. Even minor adjustments within these ranges can significantly improve or deteriorate combustion quality and NO_x emissions. As a result, the burners and subsequently the entire unit is very sensitive to minor changes in fuel heating value, fuel moisture, fuel grindability and burner heat input (load).

IV. Evaluation:

A. <u>Secondary Air Velocity</u>: Secondary air velocity varied from 116 to 129 fps through the air register/burner throat. This would normally be well within the acceptable range of most burner manufacturer guidelines. In this case however, the close proximity of the target wall combined with the very narrow upper furnace may suggest lowering both the secondary air and the primary air velocity.

B. <u>Primary Air Velocity</u>: The primary air velocity as calculated by Burns & McDonnell is 97 fps. If correct, then we believe this to be too high for this furnace. For a secondary air velocity of 129fps we would expect to see DB Riley target about 80 fps for primary air velocity.

C. <u>SA/PA Velocity Ratio</u>: DB-Riley refers to this as V_S/V_N. The secondary air-to-primary air velocity ratio during the tests was about 1.3. Lowering the primary air velocity to 80 fps would raise the ratio to about 1.6, which is more in line with most successful low NO_X burner installations.

D. <u>Furnace Plan Area</u>: The DB-Riley design data sheet indicates a calculated furnace flue gas velocity of about 26.8 fps. We confirm the same number, as long as the location under consideration is within the burner zone. The furnace depth however, reduces from 35 feet to 15 feet just above the top burner deck. This reduces plan area from 1208 ft^2 to 518 ft^2, which increases velocity from 26.8 fps to 62 fps. This increase in gas velocity as it approaches the radiant heat transfer sections significantly shortens the time available for burnout completion and additional heat transfer. Very little can be done about it on an existing furnace, which places even more emphasis on completing the burnout before reaching the upper furnace.

E. <u>Controls</u>: The controls on both of these units are old pneumatic relays originally designed by Republic. They are antiquated in every sense of the word. They are hard to program, are very inflexible, and hard to calibrate. However, they do function. After walking these units down 10 times in three days under a variety of firing conditioned it is our opinion that there is no control system capable of correcting the observed combustion problems. The problems are rooted in burner front mixing, furnace height, furnace plan area, burner throat size and burner nozzle size, but not in controls. A new state-of-the-art control system may enhance the technician's ability to cope with the system, but will not fix it.

V. Conclusions:

A. Performance: Based upon the information we have at this time, we have drawn the following conclusions regarding the operation of units H1 and H2 and their performance:

1. Adequate NO_x reduction on these units will be difficult because of the close proximity of the rear wall, the major flow area reduction in the upper furnace gas path, the small amount of freeboard above the burners and the small burner throat.
2. The primary air velocity is probably too high.
3. The secondary/primary air velocity ratio is too low.
4. The burner/air register combination is much too sensitive to changes in load and fuel quality.
5. The superheater and reheater surfaces are too small.
6. The high and uneven temperatures combined with the presence of flame in the upper furnace will increase tube leak incidents.
7. The high gas temperatures combined with the presence of flame in the upper furnace will increase radiant superheater slagging and pluggage.

B. Performance Testing: Based upon the three days of observation and evaluation it is our opinion that this unit would be an unacceptable performer with increased maintenance and would require constant adjustment to follow coal quality and load. For those reasons a performance test for the purpose of acceptance seems premature. In our opinion these units are not ready for acceptance testing if performance and operability as witnessed during this investigation is representative. The units probably can maintain NO_x below .50 lb/10^6Btu. However, O_2 is unpredictably unbalanced on both units, opacity on H2 frequently spikes, steam temperature is low on both units, and reheat tubing metal temperatures go into high temperature alarm on H2. These are not problems which have to accompany the installation of low NO_x burners.

Big Rivers Elecreic Corporation, Inc.
HMP&L Station Two, Unit 1 Performance

Project No. 97-274-3-001 7/14 - 7/17/97

Item	Units	Ready Pile Coal (7/15/97)		Lamam Coal (7/16/97)		Westwood Coal (7/17/97)	
		Test No. 4	Test No. 2	Test No. 6	Test No. 8	Test No. 10	Test No. 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		165 Mw	166 Mw	161 Mw	161 Mw	162 Mw	161 Mw
Clock Time							
Start		4:21 PM	12:01 PM	10:00 AM	3:15 PM	12:29 PM	10:16 AM
End		5:19 PM	2:18 PM	11:30 PM	4:44 PM	1:36 PM	11:14 AM
Coal Analysis, Ultimate							
Carbon	%	65.33	67.35	63.75			62.24
Sulfur	%	2.78	2.45	2.48			3.40
Hydrogen	%	4.64	4.82	4.77			4.67
Oxygen	%	6.07	5.79	5.45			7.16
Nitrogen	%	1.38	1.43	1.35			1.32
Chlorine	%	0.09	0.09	0.09			0.09
Moisture	%	9.56	9.79	12.08			10.78
Ash	%	9.93	8.28	10.02			10.34
Total	%	100.00	100.00	99.99			100.00
Coal Analysis, Proximate							
Fixed Carbon	%	46.23	46.58	43.02			44.12
Volatile Matter	%	34.26	35.35	34.88			34.76
Moisture	%	9.56	9.79	12.08			10.78
Ash	%	9.93	8.28	10.02			10.34
Total	%	100.00	100.00	100.00			100.00
Misc. Coal Data							
Heating Value	Btu/lb	11,459	11,819	11,239			11,382
Grindability	HGI	50.3	50.5	49.5			49
Ash Fusion Temperatures							
Initial Def., Reducing	°F	1966	1998	1996			1937
Softening, Reducing	°F	2034	2045	2048			1965
Hemispherical, Reducing	°F	2078	2115	2104			1999
Fluid, Reducing	°F	2119	2290	2258			2225
Initial Def., Oxidizing	°F	2286	2402	2433			2444
Softening, Oxidizing	°F	2323	2434	2478			2486
Hemispherical, Oxidizing	°F	2429	2471	2498			2513
Fluid, Oxidizing	°F	2450	2527	2511			2539
Ash Mineral Analysis							
MnO_2	%	0.05	0.05	0.03			0.03
SiO_2	%	43.56	45.81	48.62			44.23
Fe_2O_3	%	20.11	20.06	21.32			29.65
Al_2O_3	%	19.07	20.71	20.59			17.55
TiO_2	%	1.07	1.18	1.04			0.86
CaO	%	6.13	4.34	2.46			1.98
MgO	%	0.97	0.80	0.73			0.76
K_2O	%	1.92	2.00	1.92			1.92
Na_2O	%	0.40	0.38	0.39			0.31
SO_3	%	5.73	3.78	1.90			1.71
Undetermined	%	1.00	0.89	1.00			1.00
Total	%	100.00	100.00	100.00	0	0	100.00
Emissions							
LOI	%	8.10	5.70	8.54	10.12	8.85	8.16
SO_2	lb/10⁶Btu	0.226	0.297	0.200	0.229	0.189	0.156
CO_2	%	12.0	12.0	11.6	11.7		11.8
NO_X	lb/10⁶Btu	0.487	0.490	0.483	0.484		0.493
Opacity	%	15.2	13.1	24.6	24.0	24.3	21.1
Removal Efficiency	%	95.8	94.5	95.5	94.9	96.2	96.0

Item	Units	Ready Pile Coal (7/15/97)		Lamam Coal (7/16/97)		Westwood Coal (7/17/97)	
		Test No. 4	Test No. 2	Test No. 6	Test No. 8	Test No. 10	Test No 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		165 Mw	166 Mw	161 Mw	161 Mw	162 Mw	161 Mw
Main Unit Data							
O_2, East	%	2.2	2.9	2.4	3.0	2.3	3.1
O_2, West	%	3.8	3.0	4	3.3	4.2	3.5
O_2, Average	%	3.0	3.0	3.2	3.2	3.3	3.3
Excess Air	%	16.2	16.2	17.4	17.4	18.1	18.1
Unit Load	Mw	165	166	161	161	162	161
Steam Flow	kpph	1080	1083	1020	1040	1040	1040
SH Temperature	°F	964	966	995	994	997	990
RH Temperature	°F	938	938	961	963	966	972
SH Spray Flow	kpph	0	0	0	0	0	0
RH Spray Flow	kpph	0	0	0	0	0	0
AH Gas Out Temperature, East	°F	332	338	329	327	327	330
AH Gas Out Temperature, West	°F	332	338	323	322	324	322
Windbox Temperature	°F	640	640	608	609	620	624
Windbox Pressure	in. wc	14	14	14	13	14	13
Burner Settings							
Shroud A1	%	82	82	71	78	75	80
Shroud A2	%	83	83	72	78	75	80
Shroud A3	%	82	82	71	79	75	80
Shroud A4	%	82	82	74	75	75	79
Shroud B1	%	81	81	75	76	75	80
Shroud B2	%	81	81	67	77	68	80
Shroud B3	%	82	82	74	76	75	80
Shroud B4	%	81	81	62	76	66	80
Vanes A1	%	35	35	35	35	35	35
Vanes A2	%	35	35	35	35	35	35
Vanes A3	%	35	30	35	32	35	32
Vanes A4	%	35	30	35	30	35	30
Vanes B1	%	35	4	35	32	35	32
Vanes B2	%	30	30	30	30	35	30
Vanes B3	%	30	30	30	33	32	35
Vanes B4	%	35	30	35	30	32	30
Tip	inches	All Flush	All Flush	All Flush	All Flush	All Flush	All Flush
Pulverizer A Data							
Pulverizer Exit End d/p	in. wc	3.8	3.6	4.0*	4.3*	4	3.8
Seal Air d/p	in. wc	14.5	14.7	11.7*	13.0*	12	13.8
Classifier/Furnace d/p	in. wc	20.0	20.0	22.3*	23.0*	21	22.5
Pulverizer d/p	in. wc	4.5	4.2	5.5*	5.2	5	4.8
PA Fan Pressure	in. wc	38	38	42	40	39	40
Bypass Damper Demand	%	0 (Man)	0 (Man)	0 (Man)	0 (Man)	0 (Man)	0 (Man)
Hot Air Damper Demand	%	100 (Man)	100 (Man)	100 (Man)	100 (Man)	100 (Man)	100 (Man)
Temp. Air Damper Demand	%	63 (Man)	64 (Man)	57 (Man)	55 (Man)	55 (Man)	54 (Man)
Rating Damper Demand	%	32 (Auto)	32 (Auto)	57 (Auto)	58 (Auto)	52 (Auto)	45 (Auto)
Temperature Demand	%	44 (Man)	45 (Man)	44 (Man)	44 (Man)	44 (Man)	44 (Man)
Classifier Temperature	°F	150	147	143	145	143	144
A-1 Feeder Speed Demand	%	50	50	53	51	49	50
A-2 Feeder Speed Demand	%	50	50	53	50	46	49
Mill Kw Set Point	Kw	560	560	552	552	559	559

Item	Units	Ready Pile Coal (7/15/97)		Lanam Coal (7/16/97)		Westwood Coal (7/17/97)	
		Test No. 4	Test No. 2	Test No. 6	Test No. 8	Test No. 10	Test No. 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		165 Mw	166 Mw	161 Mw	161 Mw	162 Mw	161 Mw
Pulverizer B Data							
Pulverizer East End d/p	in. wc	4.9	4.9	6.1*	5.3	6.5	5.1
Seal Air d/p	in. wc	17.5	18.0	17.3*	17.7	17	17
Classifier/Furnace d/p	in. wc	19	18	20	18	19	20
Pulverizer d/p	in. wc	4.4	4.4	5.0*	4.9	5	4.8
PA Fan Pressure	in. wc	37	37	39	38	37	38.5
Bypass Damper Demand	%	0 (Man)	0 (Man)	0 (Man)	0 (Man)	0 (Man)	0 (Man)
Hot Air Damper Demand	%	100 (Man)	100 (Man)	100 (Man)	100 (Man)	100 (Man)	100 (Man)
Temp. Air Damper Demand	%	62 (Man)	61 (Man)	56 (Man)	55 (Man)	57 (Man)	57 (Man)
Rating Damper Demand	%	41 (Auto)	43 (Auto)	56 (Auto)	56 (Auto)	52 (Auto)	52 (Auto)
Temperature Demand	%	51 (Man)	50 (Man)	51 (Man)	51 (Man)	52 (Man)	52 (Man)
Classifier Temperature	°F	150	146	141	145	145	144
B-1 Feeder Speed Demand	%	44	50	46	46	45	43
B-2 Feeder Speed Demand	%	44	49	45	46	45	43
Mill Kw Set Point	Kw	564	564	561	561	573	573
[illegible] Temperatures							
Door No. 1 - Elev. 565'	°F	1700	1655	1630	1635	1620	1650
Door No. 2 - Elev. 565'	°F						
Door No. 7 - Elev. 521' 6"	°F	2050	2350	2070	2180	2170	2090
Door No. 8 - Elev. 521' 6"	°F	2125	2150	2170	2075	2200	2100
Door No. 9 - Elev. 521' 6"	°F	2110	2100	2130	2025	2170	2170
Door No. 10 - Elev. 521' 6"	°F	2080	2090	1990	2135	1970	2200
Door No. 11 - Elev. 512'	°F	2475	2490	2470	2480	2410	2490
Door No. 15 - Elev. 512'	°F	2500	2580	2390	2435	2420	2450
Door No. 16 - Elev. 502' 10"	°F	2500	2530	2430	2115	2336	2370
Door No. 17 - Elev. 502' 10"	°F	2585	2565	2515	2500	2435	2460
Door No. 20 - Elev. 482' 2"	°F	2510	2540	2410	2490	2505	2450
Door No. 22 - Elev. 482' 2"	°F	2525	2440	2500	2250	2250	2260
Door No. 26 - Elev. 482' 2"	°F			2610	2570	2520	2540
Door No. 27 - Elev. 482' 2"	°F	2675	2570	2665	2600	2610	2575
Door No. 29 - Elev. 482' 2"	°F	2575	2575	2535	2410	2425	2570
Door No. 30 - Elev. 472'	°F	2510	2540	2450	2400	2290	2400
Door No. 31 - Elev. 472'	°F	2550	2508	2330	2390	2385	2340
Door No. 32 - Elev. 465' 6"	°F			1860	2290	2128	1920
Door No. 33 - Elev. 465' 6"	°F	2180	2150	2050	2185	2080	2150
Door No. 34 - Elev. 465' 6"	°F	2110	2030	1990	2120	2070	2120
Door No. 35 - Elev. 465' 6"	°F	2480	2250	2320	2340	2140	2270
Door No. 36 - Elev. 465' 6"	°F	2410	2100	2280	2225	2160	2145
Door No. 37 - Elev. 465' 6"	°F	2550	2525	2390	2375	2420	2410
Scrubber Sludge Color			Off White				
Bottom Ash Water Color			Clear				
Sootblowing Pattern/Freq.							

Big Rivers Elecrric Corporation, Inc
HMP&L Station Two, Unit 2 Performance

Project No. 97-274-3-001 | 7/14 - 7/17/97

Item	Units	Ready Pile Coal (7/15/97)		Lamm Coal (7/16/97)		Patriot Coal (7/17/97)	
		Test No. 3	Test No. 1	Test No. 5	Test No. 7	Test No. 11	Test No. 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		162 Mw	162 Mw	158 Mw	161 Mw	161 Mw	161 Mw
Clock Time							
Start		3:10 PM	9:50 AM	9:49 AM	2:07 PM		
End		5:06 PM	1:15 PM	11:18 AM	4:20 PM		
Coal Analysis, Ultimate							
Carbon	%	66.02	65.33	63.86			
Sulfur	%	2.70	2.57	2.39			
Hydrogen	%	4.72	4.69	4.75			
Oxygen	%	6.71	6.83	5.35			
Nitrogen	%	1.40	1.39	1.35			
Chlorine	%	0.09	0.09	0.09			
Moisture	%	9.15	10.07	12.30			
Ash	%	9.20	9.02	9.90			
Total	%	99.99	99.99	99.99			
Coal Analysis, Proximate							
Fixed Carbon	%	45.61	45.39	43.25			
Volatile Matter	%	36.04	35.52	34.55			
Moisture	%	9.15	10.07	12.30			
Ash	%	9.20	9.02	9.90			
Total	%	100.00	100.00	100.00			
Misc Coal Data							
Heating Value	Btu/lb	11,671	11,622	11,190			
Grindability	HGI	52.5	51	48.5			
Ash Fusion Temperatures							
Initial Def., Reducing	°F	1957	1983	2024			
Softening, Reducing	°F	2015	2032	2082			
Hemispherical, Reducing	°F	2058	2100	2201			
Fluid, Reducing	°F	2195	2195	2360			
Initial Def., Oxidizing	°F	2385	2375	2404			
Softening, Oxidizing	°F	2393	2417	2450			
Hemispherical, Oxidizing	°F	2433	2453	2502			
Fluid, Oxidizing	°F	2470	2490	2540			
Ash Mineral Analysis							
MnO_2	%	0.04	0.04	0.03			
SiO_2	%	45.87	45.87	49.02			
Fe_2O_3	%	20.60	20.11	19.78			
Al_2O_3	%	19.31	20.01	21.76			
TiO_2	%	0.99	1.10	0.96			
CaO	%	4.79	4.65	2.43			
MgO	%	0.80	0.87	0.76			
K_2O	%	1.94	2.08	1.94			
Na_2O	%	0.36	0.38	0.40			
SO_3	%	4.30	4.00	1.91			
Undetermined	%	1.00	0.89	1.01			
Total	%	100.00	100.00	100.00	0	0	0
Emissions							
LOI	%	7.92	6.66	7.58	7.75		
SO_2	lb/10^6Btu	0.227	0.318	0.192	0.160		
CO_2	%	11.8	11.8	11.8	12.1		
NO_x	lb/10^6Btu	0.437	0.418	0.478	0.419		
Opacity	%	16.5	18.2	31.3	32.3		
Removal Efficiency	%	95.3	95.1	95.9	96.3		

Item	Units	Ready Pile Coal (7/15/97)		Lansen Coal (7/16/97)		Patriot Coal (7/17/97)	
		Test No. 3	Test No. 1	Test No. 5	Test No. 7	Test No. 11	Test No. 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		162 Mw	162 Mw	158 Mw	161 Mw	161 Mw	161 Mw
Main Unit Data							
O_2 East	%	3.7	3.3	3.6	3.2		
O_2 West	%	4.4	4.1	4.5	4.0		
O_2 Average	%	4.1	3.7	4.1	3.6		
Excess Air	%	23.5	20.7	23.3	20.0		
Unit Load	Mw	162	162	158	161		
Steam Flow	kpph	1150	1145	1120	1130		
SH Temperature	°F	903	1000	1001	1000		
RH Temperature	°F	997	993	983	991		
SH Spray Flow	kpph	0	0	0	0		
RH Spray Flow	kpph	0	0	0	0		
AH Gas Out Temperature, East	°F	323	325	321	324		
AH Gas Out Temperature, West	°F	333	337	333	335		
Windbox Temperature	°F	630	628	622	625		
Windbox Pressure	in. wc	16	16	15	16		
Burner Settings							
Shroud A1	%	68	68	65	66		
Shroud A2	%	69	69	65	66		
Shroud A3	%	68	68	58	59		
Shroud A4	%	69	69	80	68		
Shroud B1	%	69	69	80	66		
Shroud B2	%	69	69	80	65		
Shroud B3	%	68	68	75	66		
Shroud B4	%	69	69	75	66		
Vanes A1	%	35	35	35	35		
Vanes A2	%	35	35	35	35		
Vanes A3	%	35	32	35	32		
Vanes A4	%	35	32	35	32		
Vanes B1	%	35	35	35	4		
Vanes B2	%	30	31	30	33		
Vanes B3	%	30	30	30	32		
Vanes B4	%	35	30	35	28		
Tip	inches	All Flush	All Flush	All Flush	All Flush		
Pulverizer A Data							
Pulverizer Best End d/p	in. wc	4.7	5.2	5.3	5.4		
Seal Air d/p	in. wc	14.2	14.2	13	12.5		
Classifier/Furnace d/p	in. wc	17	17.3	18.5	18.1		
Pulverizer d/p	in. wc	4.1	4.2	4.35	4.5		
PA Fan Pressure	in. wc	37	39	39.5	43		
Bypass Damper Demand	%	0 (Man)	0 (Man)	0 (Man)	0 (Man)		
Hot Air Damper Demand	%	100 (Man)	100 (Man)	100 (Man)	100 (Man)		
Temp. Air Damper Demand	%	*66 (Man)*	50 (Man)	62 (Man)	58 (Man)		
Rating Damper Demand	%	32 (Auto)	33 (Auto)	38 (Auto)	42 (Auto)		
Temperature Demand	%	50 (Man)	50 (Man)	50 (Man)	50 (Man)		
Classifier Temperature	°F	144	147	142	145		
A-1 Feeder Speed Demand	%	47	49	50	52		
A-2 Feeder Speed Demand	%	45	45	49	50		
Mill Kw Set Point	Kw	543	543	546	543		

Item	Units	Ready File Coal (7/15/97)		Lanam Coal (7/16/97)		Patriot Coal (7/17/97)	
		Test No. 3	Test No. 1	Test No. 5	Test No. 7	Test No. 11	Test No. 9
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
		162 Mw	162 Mw	158 Mw	161 Mw	161 Mw	161 Mw
Pulverizer Data							
Pulverizer End End d/p	in. wc	5.2	5.8	5.15 *	6.5		
Seal Air d/p	in. wc	16	15.7	17	15.7		
Classifier/Furnace d/p	in. wc	4.8	16.8	17.75	17.7		
Pulverizer d/p	in. wc	45	4.9	5.15	5.5		
PA Fan Pressure	in. wc	38	38	39	40		
Bypass Damper Demand	%	0 (Man)	0 (Man)	0 (Man)	0 (Man)		
Hot Air Damper Demand	%	100 (Man)	100 (Man)	100 (Man)	100 (Man)		
Temp. Air Damper Demand	%	66 (Man)	64 (Man)	58 (Man)	59 (Man)		
Rating Damper Demand	%	22 (Auto)	22 (Auto)	36 (Auto)	35 (Auto)		
Temperature Demand	%	42 (Man)	42 (Man)	42 (Man)	42 (Man)		
Classifier Temperature	°F	144	145	141	143		
B-1 Feeder Speed Demand	%	51	48	47.5	51		
B-2 Feeder Speed Demand	%	51	48	47.5	51		
Mill Kw Set Point	Kw	542	542	543.5	545		
Furnace Temperatures							
Door No. 1 - Elev. 565'	°F	1700		1717	1655		
Door No. 2 - Elev. 565'	°F	1662		1700	1730		
Door No. 6 - Elev. 521' 6"	°F	2000	2096	2040	1975		
Door No. 7 - Elev. 521' 6"	°F	2250	2317	2140	2300		
Door No. 8 - Elev. 521' 6"	°F	2050	2114	2050	2000		
Door No. 9 - Elev. 521' 6"	°F	2076	2046	2125	2245		
Door No. 10 - Elev. 512'	°F	2525	2485	2415	2510		
Door No. 11 - Elev. 512'	°F	2520	2500	2070	2475		
Door No. 12 - Elev. 502' 10"	°F	2670	2660	2610	2635		
Door No. 13 - Elev. 502' 10"	°F	2740	2550	2630	2690		
Door No. 16 - Elev. 482' 2"	°F	2340	2575	2340	2340		
Door No. 18 - Elev. 482' 2"	°F	2560	2500	2565	2515		
Door No. 19 - Elev. 482' 2"	°F	2450	2455	2100	2355		
Door No. 22 - Elev. 482' 2"	°F	2600	2550	2510	2445		
Door No. 23 - Elev. 482' 2"	°F	2660	2645	2520	2590		
Door No. 24 - Elev. 482' 2"	°F	2440	2575	2290	2345		
Door No. 25 - Elev. 472'	°F	2570	2550	2395	2310		
Door No. 26 - Elev. 472'	°F	2420	2350	2510	2380		
Door No. 27 - Elev. 465' 6"	°F	2435		2120			
Door No. 28 - Elev. 465' 6"	°F	2140	2230	2140	2125		
Door No. 29 - Elev. 465' 6"	°F			2040	2050		
Door No. 30 - Elev. 465' 6"	°F			2230	2260		
Door No. 31 - Elev. 465' 6"	°F	2170	2172	2130	2090		
Door No. 32 - Elev. 465' 6"	°F			2045	2250		
Scrubber Sludge Color			Off White				
Bottom Ash Water Color			Clear				
Sootblowing Pattern/Freq.							

Big Rivers Electric Corporation

HMP&L Station Two, Units 1 & 2 Coal Analyses

Property	Units	Unit No. 1						Unit 2			
		Emery Pile Coal (7/15/97)		Lamm Coal (7/16/97)		Westwood Coal (7/17/97)		Ready Pile Coal (7/15/97)		Lamm Coal (7/16/97)	
		Test No. 4	Test No. 3	Test No. 6	Test No. 8	Test No. 10	Test No. 9	Test No. 3	Test No. 1	Test No. 5	Test No. 7
		DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings	DBR Settings	BREC Settings
[illegible]											
Moisture	%	9.56	9.79	12.08			10.78	9.15	10.07	12.30	
Ash	%	9.95	8.28	10.02			10.34	9.20	9.02	9.90	
Volatile	%	34.25	35.35	34.88			34.76	36.04	35.52	34.55	
Fixed Carbon	%	46.23	46.58	43.02			44.12	45.61	45.39	43.25	
Total	%	100.00	100.00	100.00	0.00	0.00	100.00	100.00	100.00	100.00	0.00
HHV	Btu/lb	11,439	11,819	11,139			11,392	11,671	11,622	11,190	
Sulfur	%	2.78	2.45	2.48			3.40	2.70	2.57	2.39	
[illegible]											
Moisture	%	9.56	9.79	12.08	0.00	0.00	10.78	9.15	10.07	12.30	0.00
Carbon	%	65.53	67.35	63.75			62.24	64.02	65.33	63.86	
Hydrogen	%	4.64	4.82	4.77			4.67	4.72	4.69	4.75	
Nitrogen	%	1.38	1.43	1.35			1.32	1.40	1.39	1.35	
Chlorine	%	0.09	0.09	0.09			0.09	0.09	0.09	0.09	
Sulfur	%	2.78	2.45	2.48	0.00	0.00	3.40	2.70	2.57	2.39	0.00
Ash	%	9.95	8.28	10.02	0.00	0.00	10.34	9.20	9.02	9.90	0.00
Oxygen	%	6.07	5.79	5.45			7.16	4.71	6.88	5.33	
Total	%	100.00	100.00	99.99	0.00	0.00	100.00	99.99	99.99	99.99	0.00
[illegible]											
Initial Deformation	°F	1966	1998	1996			1923	1937	1983	2024	
Softening	°F	2034	2045	2048			1965	2015	2032	2082	
Hemispherical	°F	2078	2115	2104			1999	2058	2100	2201	
Fluid	°F	2216	2290	2258			2225	2195	2295	2340	
[illegible]											
Initial Deformation	°F	2280	2402	2433			2444	2383	2375	2404	
Softening	°F	2323	2404	2478			2486	2393	2417	2450	
Hemispherical	°F	2429	2471	2498			2513	2435	2453	2502	
Fluid	°F	2450	2527	2511			2539	2470	2490	2540	
[illegible]											
Grindability	HGI	50.5	50.5	49.5			49.0	52.5	51.0	48.5	
[illegible]											
Silica	%	41.56	43.87	46.62			44.23	43.87	43.87	49.03	
Alumina	%	19.07	20.71	28.59			17.53	18.31	20.01	21.76	
Titania	%	1.07	1.18	1.04			0.86	0.99	1.10	0.95	
Ferric Oxide	%	20.11	20.06	21.52			25.63	22.60	20.11	19.78	
Lime	%	4.12	4.34	2.40			1.95	4.79	4.63	2.43	
Magnesia	%	0.97	0.80	0.73			0.76	0.80	0.87	0.76	
Sodium Oxide	%	0.40	0.38	0.39			0.31	0.36	0.33	0.40	
Potassium Oxide	%	1.92	2.00	1.92			1.92	1.94	2.08	1.91	
Manganese Dioxide	%	0.06	0.05	0.05			0.03	0.04	0.04	0.03	
Sulfur Trioxide	%	5.73	3.78	1.90			1.71	4.30	4.00	1.91	
SILICA VALUE	N/A	61.56	64.51	66.48			51.73	63.66	64.15	68.08	
BASE/ACID RATIO	N/A	0.46	0.41	0.38			0.56	0.45	0.42	0.35	
FOULING INDEX	N/A	0.19	0.15	0.15			0.17	0.16	0.16	0.14	
SLAGGING INDEX	N/A	1.41	1.11	1.08			2.11	1.28	1.20	0.94	
[illegible]											
Hopper 5	%	0.11	0.09	0.03	0.08	0.09	0.15	0.06	0.03	0.02	0.15
Hopper 6	%	0.07	0.04	0.03	0.09	0.08	0.10	0.07	0.03	0.02	0.18
Hopper 7	%	0.09	0.04	0.02	0.04	0.10	0.12	0.08	0.02	0.07	0.09
Hopper 8	%	0.12	0.05	0.03	0.13	0.13	0.07	0.07	0.01	0.01	0.11
Hopper 9	%	0.17	0.10	0.05	0.19	0.13	0.12	0.14	0.08	0.02	0.30
Hopper 10	%	0.13	0.04	0.02	0.21	0.17	0.15	0.11	0.07	0.05	0.25
Hopper 11	%	0.13	0.09	0.03	0.16	0.13	0.12	0.14	0.06	0.07	0.77
Hopper 12	%	0.09	0.03	0.02	0.13	0.31	0.11	0.10	0.08	0.05	0.20
[illegible]											
Hopper 5	%	4.31	4.60	6.69	3.93	4.58	4.37	4.93	4.23	5.33	3.76
Hopper 6	%	5.28	3.87	4.68	4.00	5.69	4.57	4.92	3.72	4.73	4.80
Hopper 7	%	4.12	4.10	9.70	4.02	4.23	4.19	4.34	3.28	5.16	3.84
Hopper 8	%	5.45	4.55	4.62	3.87	4.25	5.15	5.42	4.20	3.84	3.55
Hopper 9	%	9.52	7.89	7.58	14.54	12.35	11.15	10.03	7.86	9.43	9.26
Hopper 10	%	18.11	5.74	19.86	13.80	17.66	18.79	11.18	9.11	9.33	12.07
Hopper 11	%	8.52	6.77	8.82	18.29	10.68	8.11	9.01	10.16	13.07	11.16
Hopper 12	%	9.50	7.09	4.32	18.39	10.88	7.84	10.50	10.57	9.49	9.35
[illegible]											
Hopper 5	%	4.21	4.60	6.69	3.93	4.58	4.38	4.95	4.23	5.33	3.77
Hopper 6	%	5.28	3.87	4.68	4.03	5.69	4.57	4.92	3.72	4.73	4.90
Hopper 7	%	4.11	4.10	9.70	4.02	4.23	4.30	4.34	3.28	5.16	3.84
Hopper 8	%	5.46	4.55	4.62	3.81	4.26	5.25	5.42	4.29	3.84	3.56
Hopper 9	%	9.54	7.90	7.58	14.37	12.21	11.16	10.04	7.87	9.43	9.29
Hopper 10	%	18.13	6.74	19.86	13.83	17.69	18.84	14.20	9.12	9.32	12.10
Hopper 11	%	8.53	6.78	3.82	18.32	10.69	8.72	9.02	10.17	13.08	11.18
Hopper 12	%	9.51	7.09	6.32	18.41	10.50	7.85	10.51	10.36	9.49	9.37
Unweighted Average	%	8.10	5.70	8.54	10.13	8.63	8.16	7.02	4.66	7.58	7.73

Secondary and Primary Air Velocity Calculations

SECONDARY AIR VELOCITY

	Units	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	Test 8	Test 9	Test 10
Average Burner Throat Dia.	in.	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Diverter Outside Dia.	in.	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Sec. Air Temp.	Deg. F	450	450	450	434	450	450	456	450	456	450
Sec. Air Press.	in. wc	12.5	12.3	12.3	12.5	12.5	12.5	12.3	12.5	12.3	12.5
Sec. Air Flow	pph	166,548	165,954	173,310	160,434	168,923	159,378	163,491	159,328	155,409	155,409
Density @ STP	lb/ft³	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751
Calculated Density	lb/ft³	0.0448509	[illegible]	0.0449590	[illegible]	[illegible]	0.0448599	0.0450599	0.0449590	[illegible]	[illegible]
Calculated Area	ft²	10.074	10.074	10.074	10.074	10.074	10.074	10.074	10.074	10.074	10.074
Velocity	fps	121	124	130	121	124	119	122	119	116	116

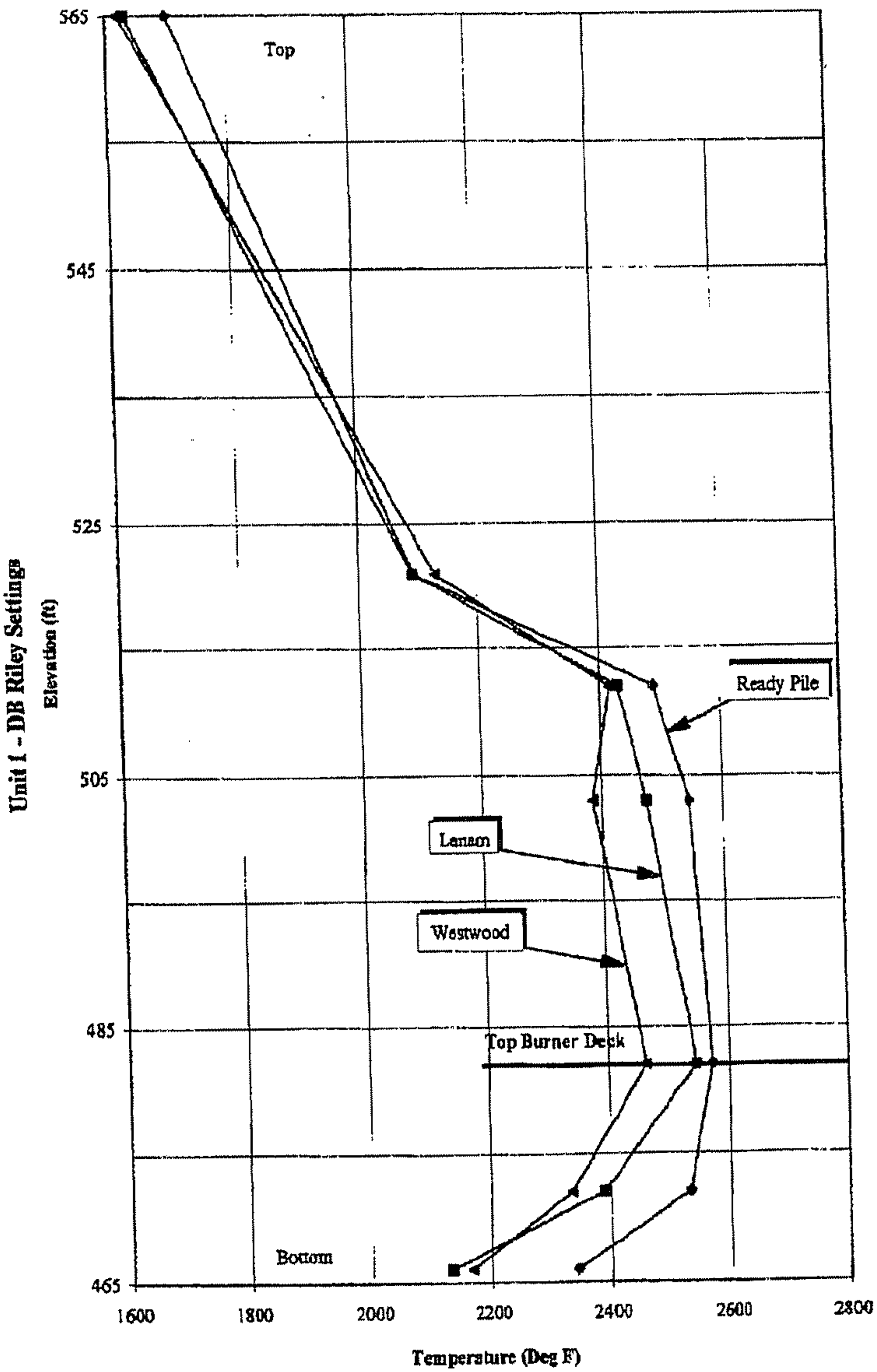
PRIMARY AIR VELOCITY

	Units	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	Test 8	Test 9	Test 10
Nozzle Dia.	in.	14.25	14.25	14.25	14.25	14.25	14.25	14.25	14.25	14.25	14.25
Spreader Area	in²	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Pri. Air Temp.	Deg. F	150	150	150	150	150	150	150	150	150	150
Pri. Air Press.	in. wc	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Pri. Air Flow	pph	22,750	22,750	22,750	22,750	22,750	22,750	22,750	22,750	22,750	22,750
Density @ STP	lb/ft³	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751	0.0751
Calculated Density	lb/ft³	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548	0.0672548
Calculated Area	ft²	0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968
Velocity	fps	97.1	97.1	97.1	97.1	97.1	97.1	97.3	97.1	97.3	97.3
Sec/Pri Velocity Ratio		1.25	1.27	1.33	1.25	1.29	1.22	1.26	1.23	1.19	1.19

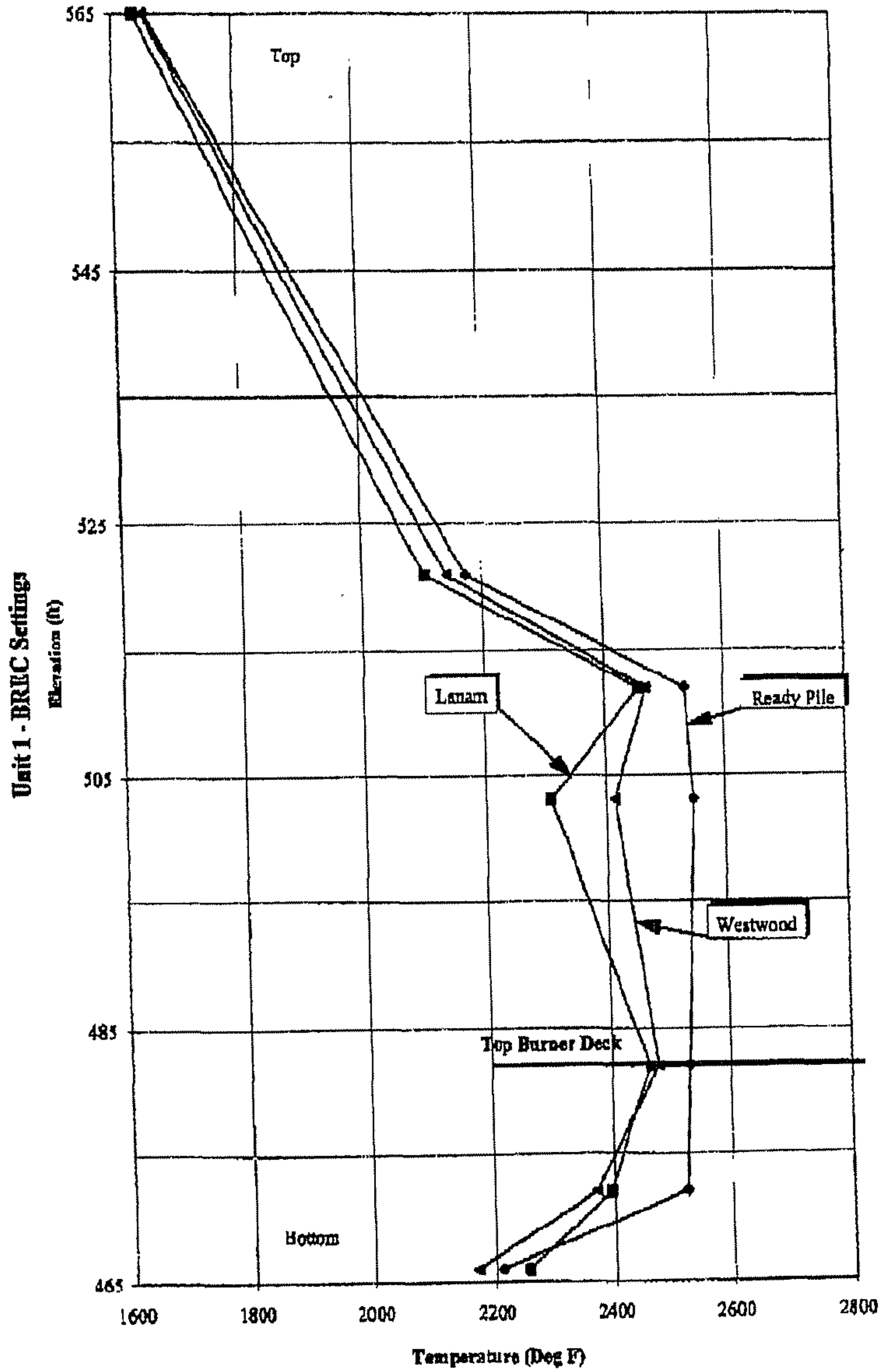
SECONDARY AIR FLOW CALCULATION

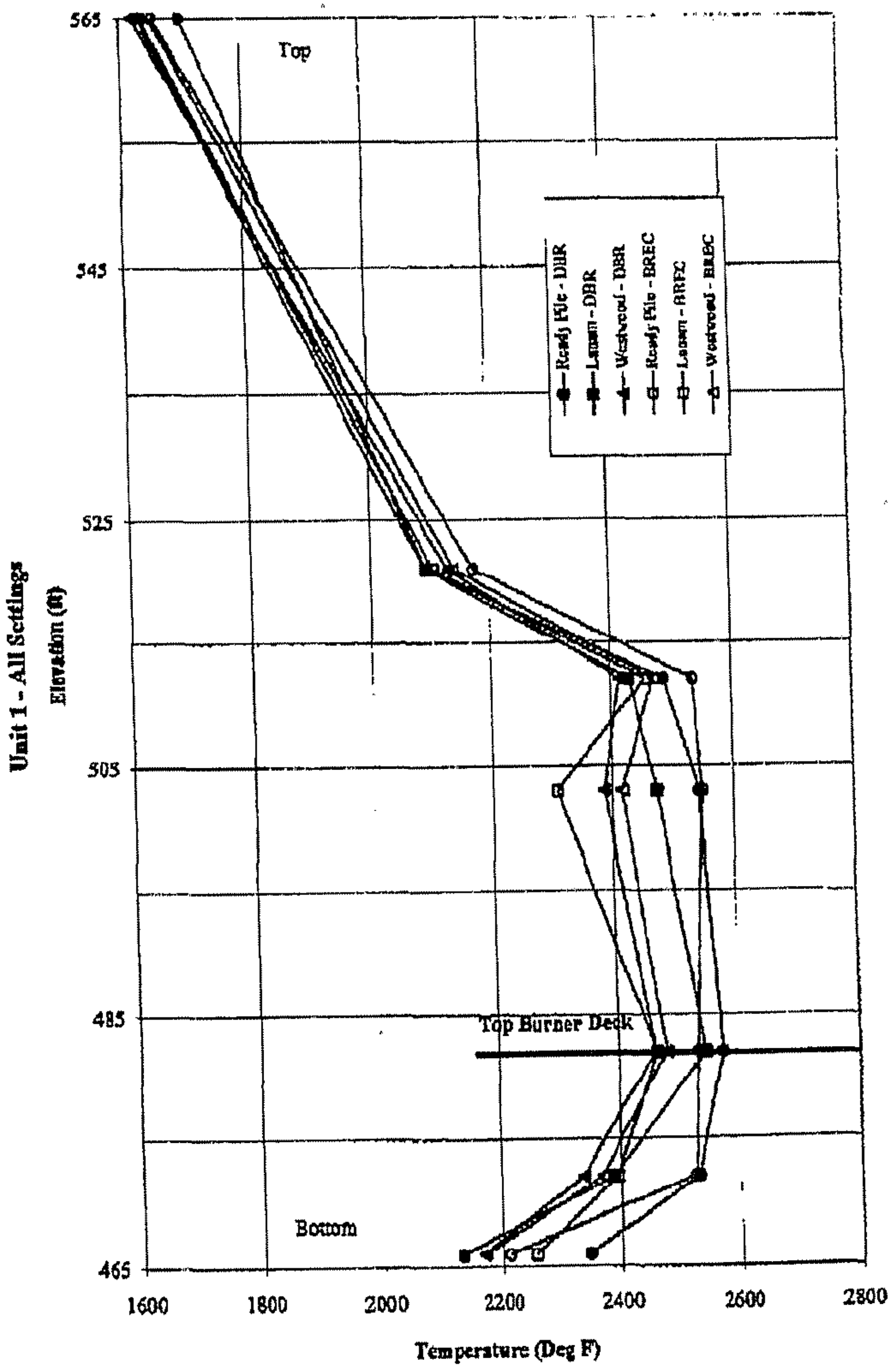
COAL ANALYSIS

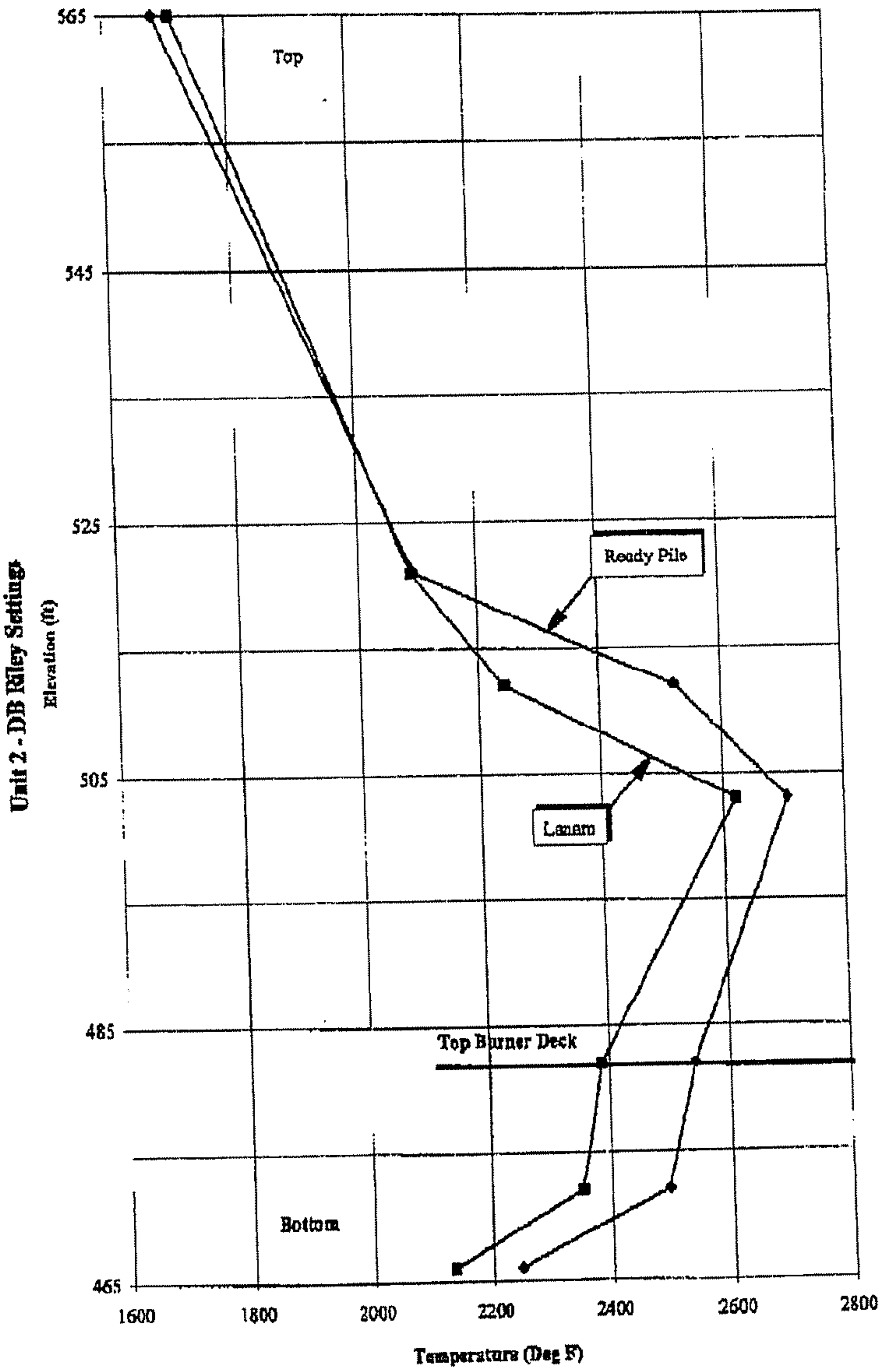
	Units	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	Test 8	Test 9	Test 10
Carbon	%	63.83%	67.33%	66.03%	63.35%	63.80%	63.79%	63.80%	63.73%	62.34%	62.29%
Hydrogen	%	4.07%	4.87%	4.72%	4.64%	4.75%	4.17%	4.77%	4.77%	4.67%	4.67%
Oxygen	%	4.89%	5.27%	4.71%	4.07%	5.32%	3.40%	5.37%	5.41%	7.19%	7.18%
Sulfur	%	2.57%	2.45%	2.78%	2.78%	2.35%	3.49%	3.39%	2.48%	3.49%	3.49%
Stoich. Air	lb/lb fuel	8.96	9.20	9.08	9.41	8.87	8.8	8.87	8.86	8.43	8.43
With Excess Air	lb/lb fuel	10.82	10.78	11.19	10.47	10.93	10.40	10.64	10.40	10.18	10.18
Total Fuel Flow	pph	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Total Air Flow	pph	1,514,120	1,509,570	1,566,870	1,465,631	1,532,785	1,456,475	1,489,529	1,456,813	1,425,271	1,425,272
Sec. Air/Burner	pph	166,514	165,954	173,310	160,434	168,923	159,378	163,491	159,428	155,409	155,409



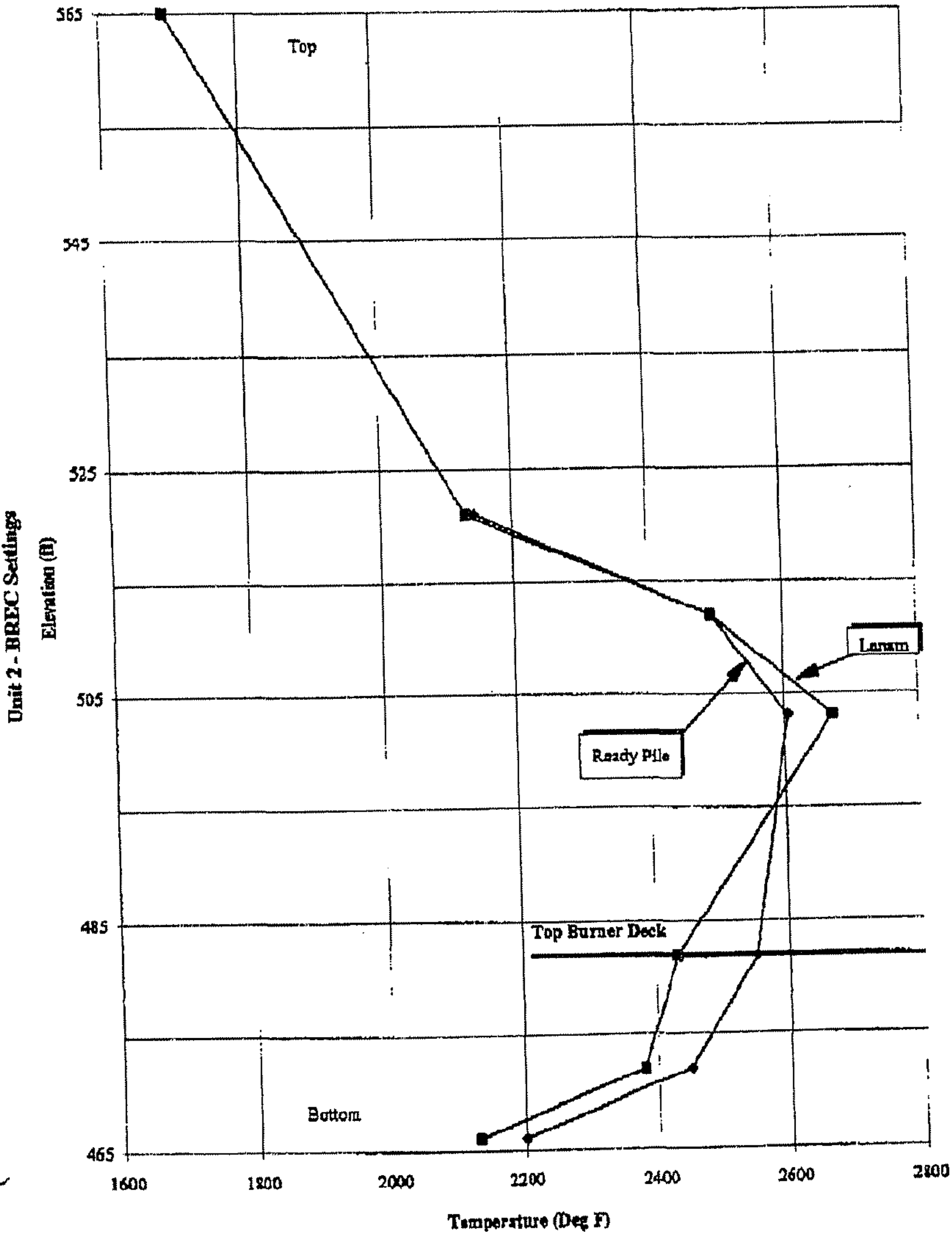
Unit 1 - DB Riley Settings
Elevation (ft)
Temperature (Deg F)
Top
Bottom
Ready Pile
Lanam
Westwood
Top Burner Deck
565
545
525
505
485
465
1600
1800
2000
2200
2400
2600
2800

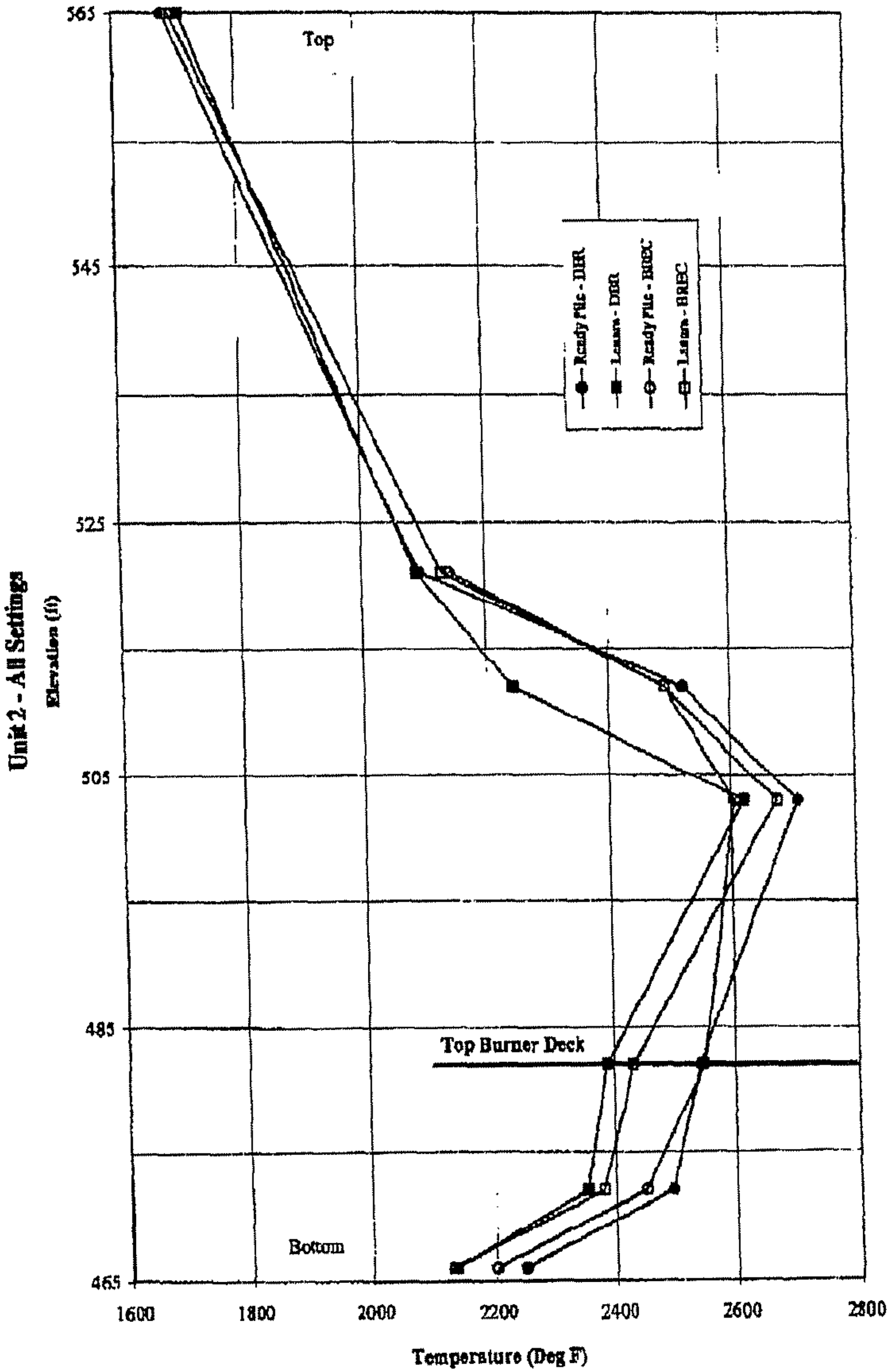

Unit 1 - BREC Settings
Elevation (ft)
565
545
525
505
485
465
Top
Bottom
Lanam
Ready Pile
Westwood
Top Burner Deck
1600
1800
2000
2200
2400
2600
2800
Temperature (Deg F)


Unit 1 - All Settings
Elevation (ft)
565
545
525
505
485
465
Top
Bottom
Top Burner Deck
Ready Pile - DBR
Larsen - DBR
Westvood - DBR
Ready Pile - BREC
Larsen - BREC
Westvood - BREC
1600
1800
2000
2200
2400
2600
2800
Temperature (Deg F)

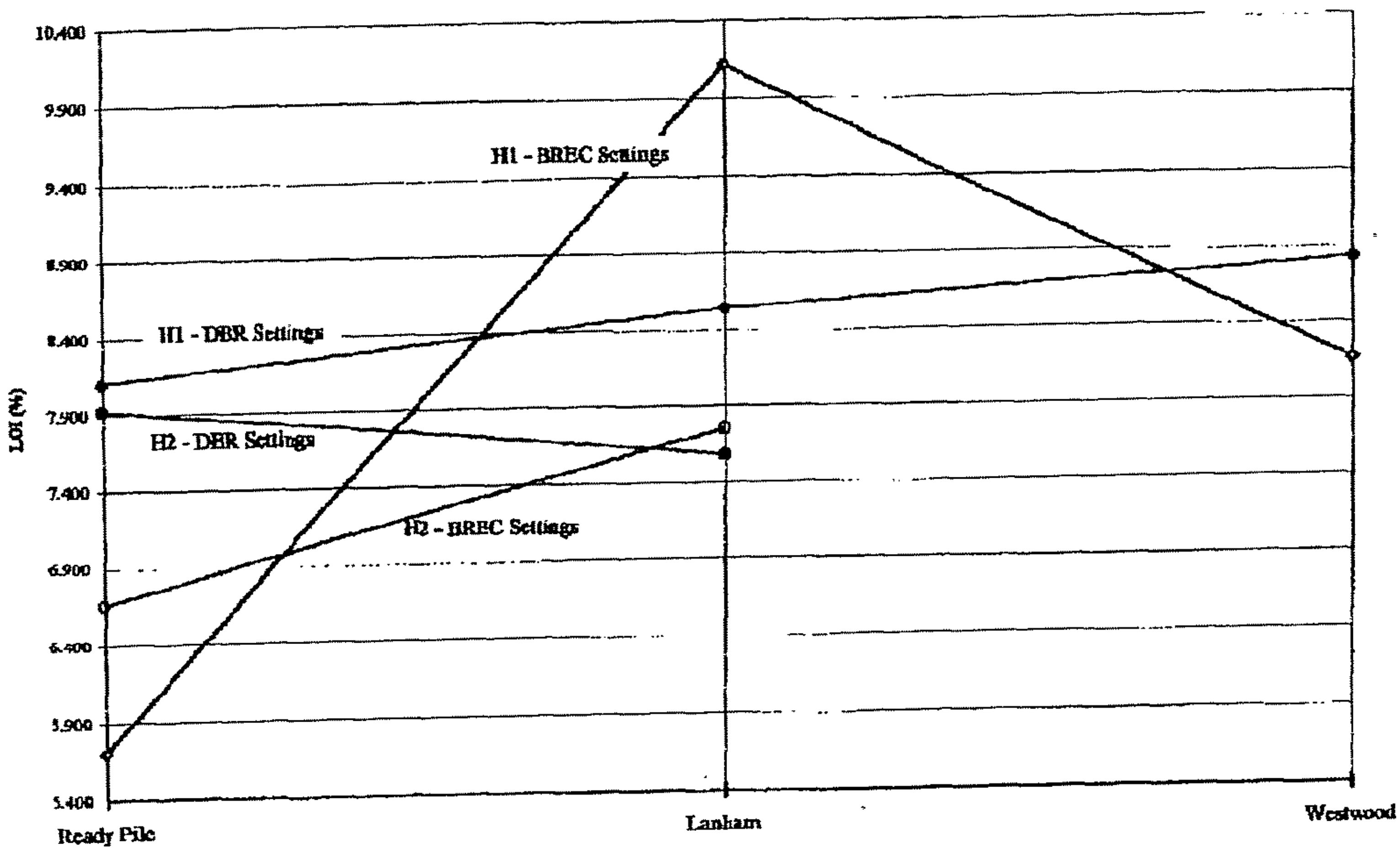


Aug 4 1997 6:42PM BURNS MCDONNELL No. 9066 P. 20

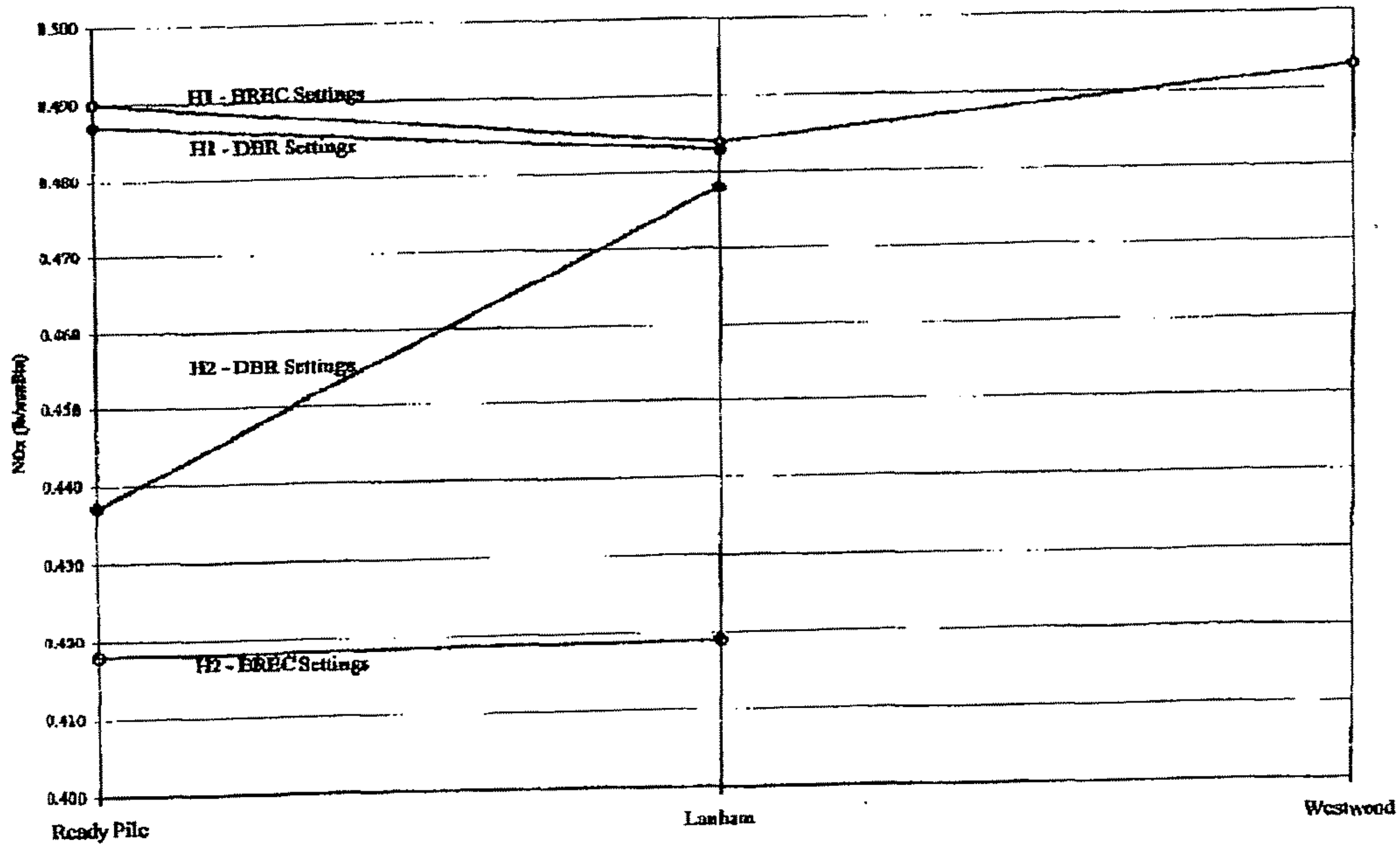

Unit 2 - BREC Settings
Elevation (ft)
565
545
525
505
485
465
Top
Bottom
Lanam
Ready Pile
Top Burner Deck
1600
1800
2000
2200
2400
2600
2800
Temperature (Deg F)


Unit 2 - All Settings
Elevation (ft)
Top
Bottom
Top Burner Deck
Ready Flic - DBR
Lasers - DBR
Ready Flic - BREC
Lasers - BREC
565
545
525
505
485
465
1600
1800
2000
2200
2400
2600
2800
Temperature (Deg F)

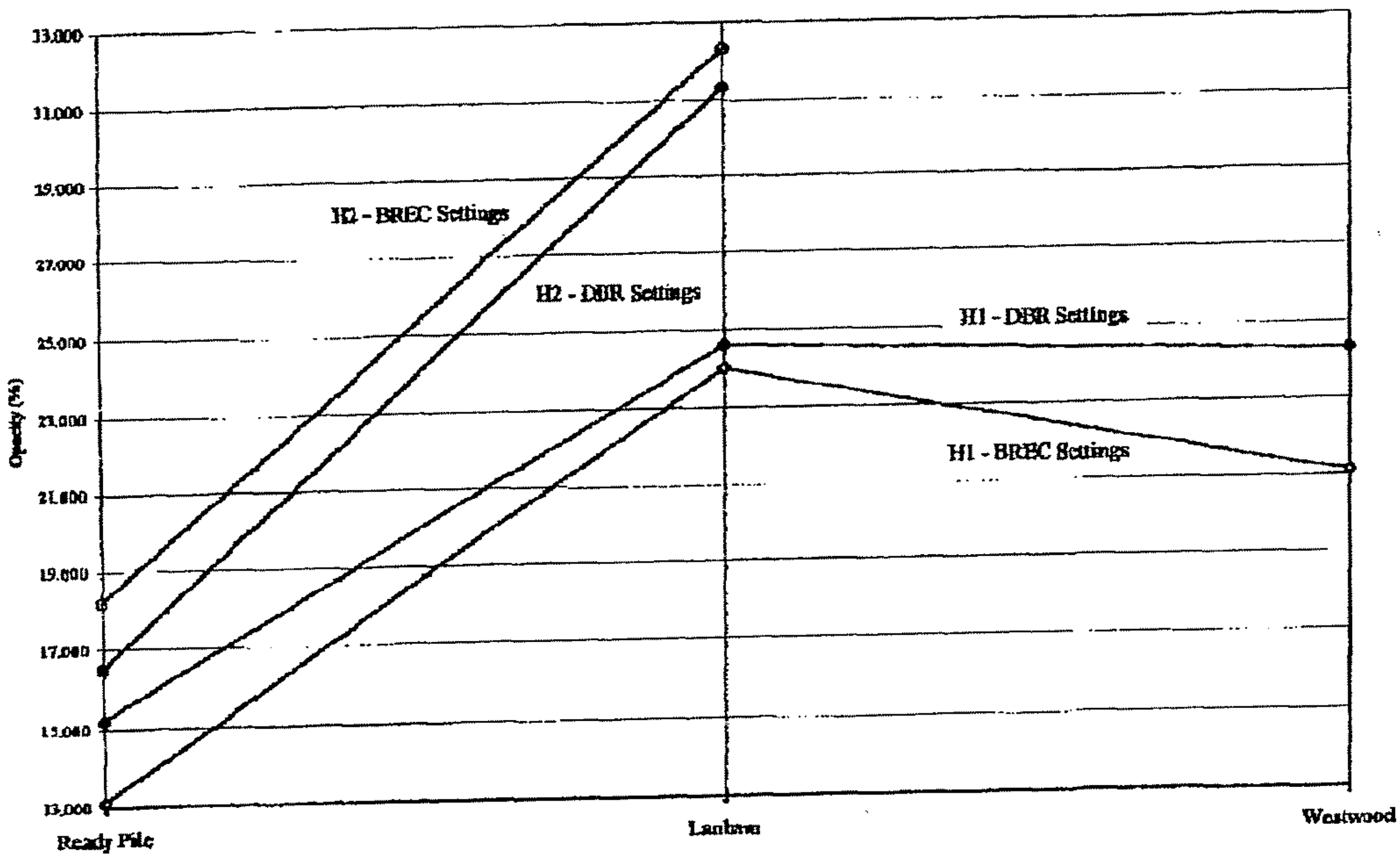
LOI Trends for DBR & BREC Settings
with Three Fuels



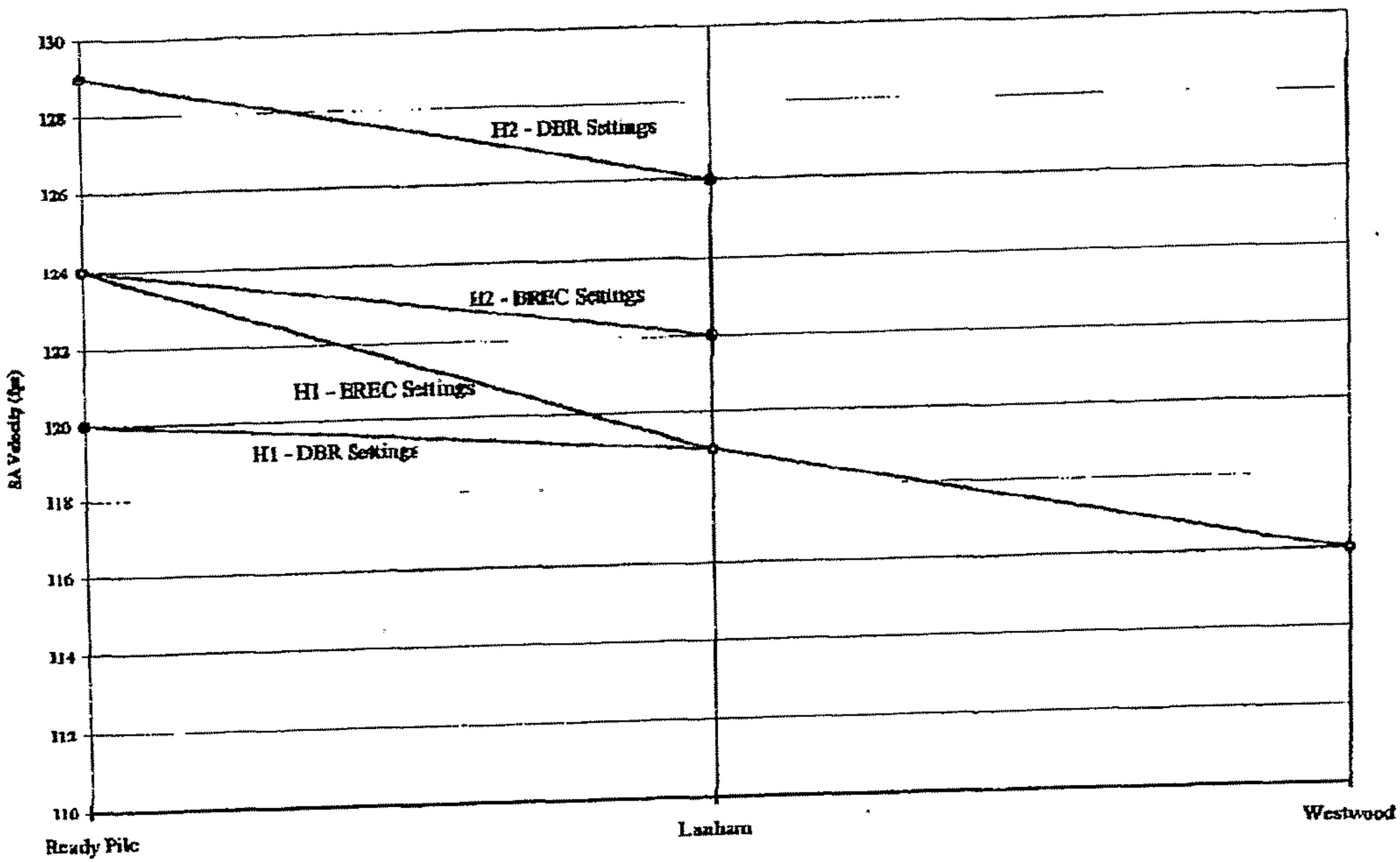
NOx Trends for DBR & BREC Settings
with Three Fuels



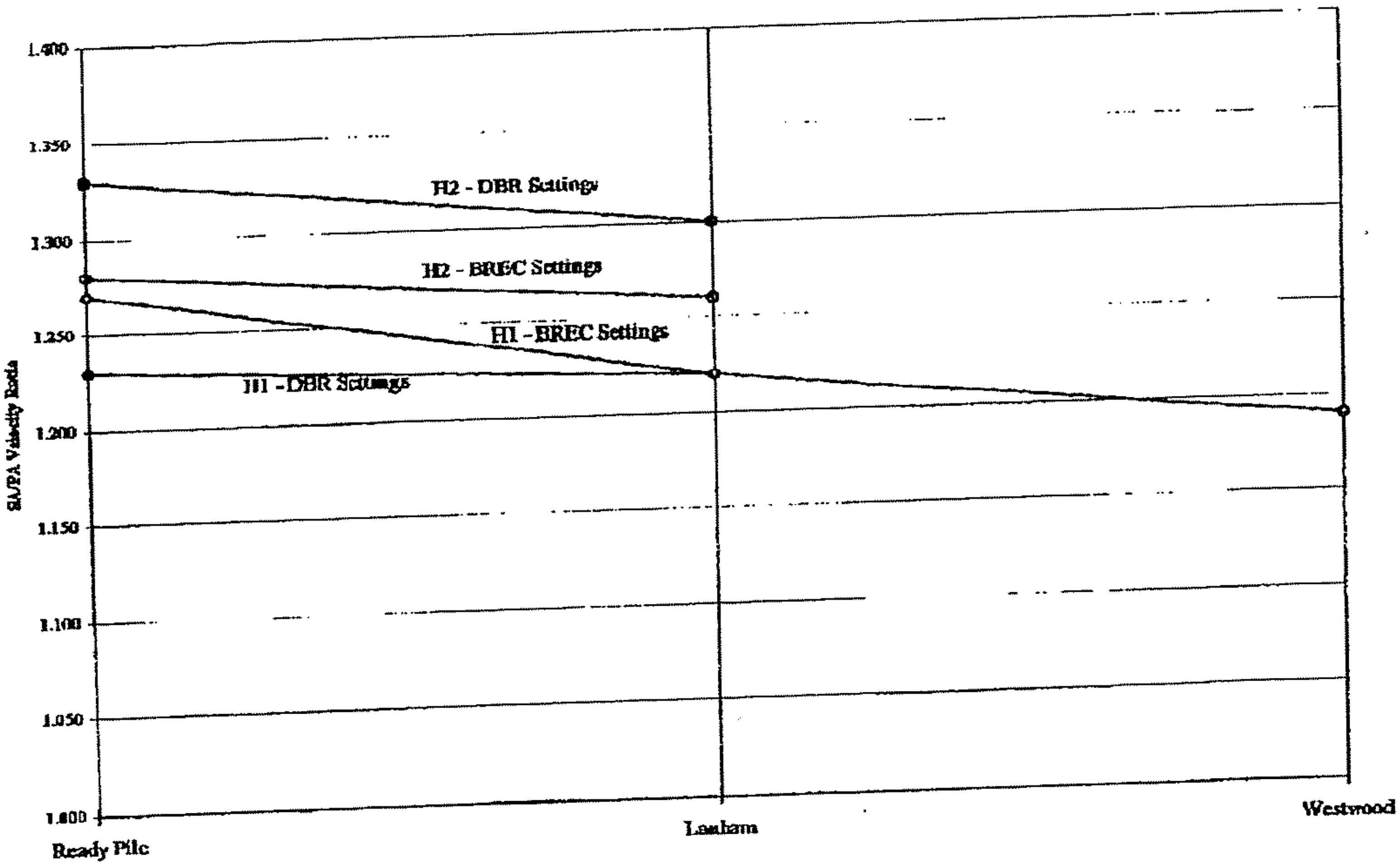
Opacity Trends for DBR & BREC Settings with Three Fuels



SA Velocity Trends for DBR & BREC Settings with Three Fuels



SA/PA Velocity Ratio Trends for DBR & BREC Settings with Three Fuels



ATTACHMENT 4

DAVID FRENCH METALLURGICAL ANALYSIS 07-009

Unit 1
South, East and West Waterwalls
Condition Assessment

CONFIDENTIAL
(RUSH)

Report 07-009
February 8, 2007

Prepared For:

WESTERN KENTUCKY ENERGY

HMP&L Station II
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D N French

David N. French, ScD
Technical Director

Lab Work by:

Jonathan Brand
Metallographic Technician

I. Introduction

HMP&L Station 2 Unit 1 experienced a coolant disruption. As a result fourteen waterwall tubes were submitted for condition assessment:

West Tube 6A, removed from elevation 512'10".
West Tube 14A, removed from elevation 492'10".
West Tube 30A, removed from elevation 512'10".
West Tube 47A, removed from elevation 492'10".

East Tube 6A, removed from elevation 512'10".
East Tube 14A, removed from elevation 492'10".
East Tube 27A, removed from elevation 512'10".
East Tube 41A, removed from elevation 492'10".

South Tube 14A, removed from elevation 512'10".
South Tube 35A, removed from elevation 492'10".
South Tube 51A, removed from elevation 492'10".
South Tube 65A, removed from elevation 512'10".
South Tube 103A, removed from elevation 512'10".
South Tube 123A, removed from elevation 512'10".

All tubes were specified as 2.5" OD x 0.203"MWT x SA-178 Grade C. They had been in service 13 months and had seen 9 start/stop cycles.

Operating Specifications		
Manufacturer:	Riley	
Unit #:	1	
Vintage:	1973	
MW:	165	
Fuel:	Bituminous	
Operating	**Pressure, psi:**	**Temperature, °F:**
Superheater:	1875	1005
Reheater:	450	1005
	Date	**Cleaner used**
Chem. Cleaning:	Dec 2005	na

II. Conclusions

1. There was no evidence of metallurgical degradation of the sample waterwall tubes resulting from the coolant disruption.
2. Typical microstructures were observed in the tubing, as for new SA-178 Gr.C.
3. There has been no significant loss of expected life of the boiler tubes from the low water event.
4. Some ID corrosion pitting was seen but deemed superficial.
5. Deposit weight density was measured on a sample from each of the three walls, and the measurements showed the waterside to be clean. Even with the high temperature excursion, the tubes have not been oxidized on the waterside.

III. Recommendations

1. Inspect attachments such as buckstays on waterwall tubes for any damage.

IV. Results and Discussion

West Waterwall tubes

Four tube samples removed from the West Waterwall for condition assessment are shown in **Fig. 1**. The samples had some light ash on the outside but were generally clean with no evidence of damage or burning. The inside of the tubes appeared clean.

Figure 1. As-received tubes from the West Waterwall.

Metallurgical samples were obtained by cross-sectioning each tube. These samples were mounted, polished, and etched to reveal their microstructure. **Figure 2** illustrates the structure of West Wall Tube 6A, which is ferrite and pearlite, the expected structures for SA178-C carbon steel tube. The pearlite and ferrite are in bands, the result of orientation during tube fabrication, **Fig. 3**. This was typical of all the waterwall tubes. A decarburized layer (no pearlite) was present on the OD surface and also on the ID, **Fig. 4**. Some slight surface corrosion was seen. The structure here looks like new tube, and shows no evidence of overheating. Similar structures were observed on the cold side of the tubes.

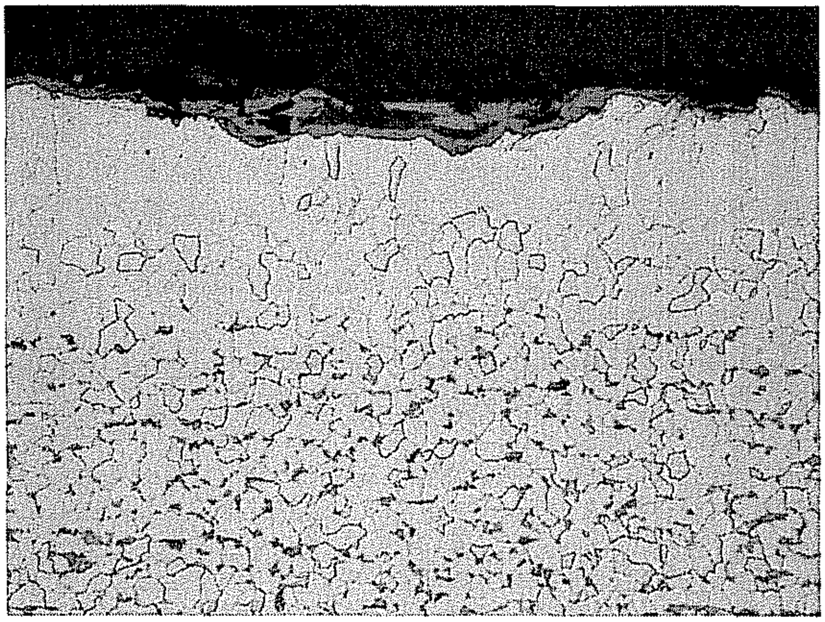


Figure 2. Decarburized layer, typical in tube manufacturing, is visible here at the OD of the hot side of Tube W-6A. 200x.

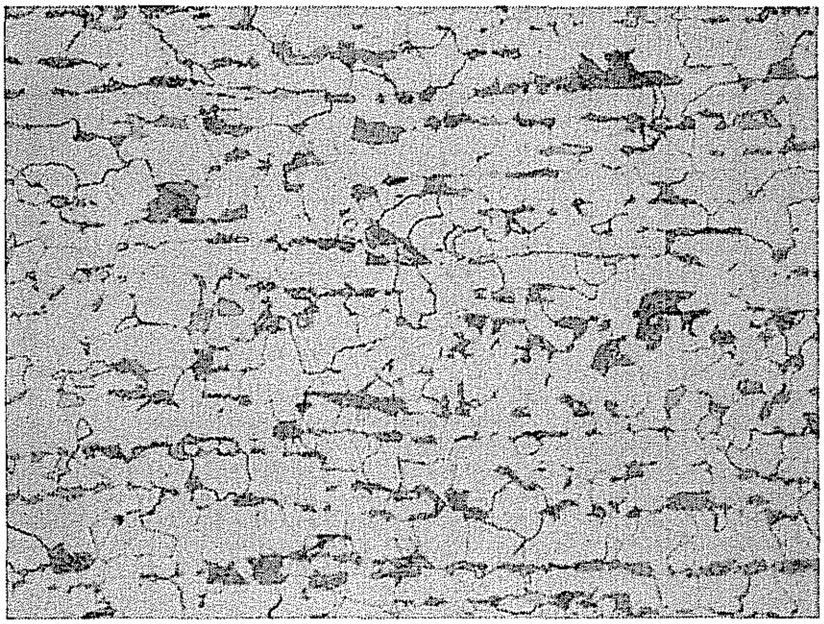


Figure 3. Typical pearlite and ferrite mid-wall microstructure at hot side of Tube W-6A, and common in all West wall tubes. 400x.

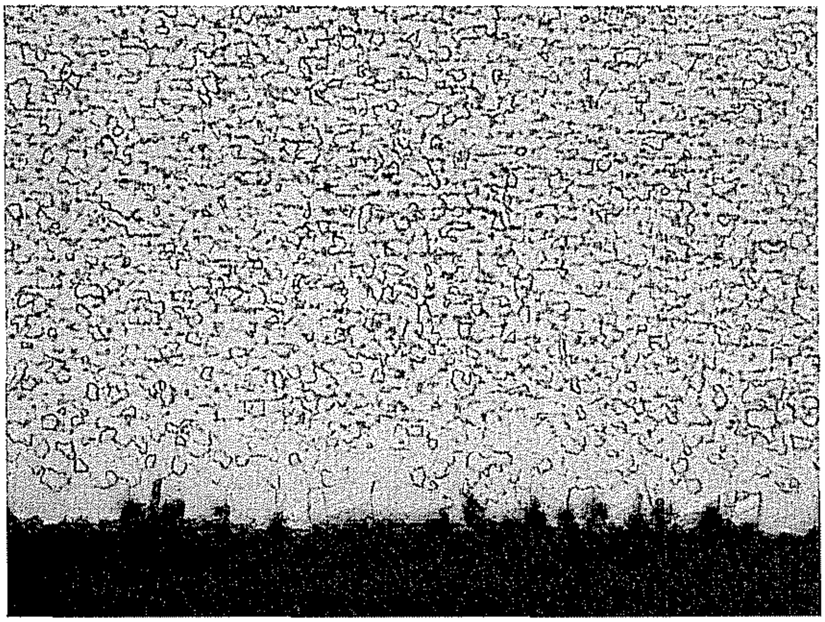


Figure 4. Slight decarburization and ID corrosion at ID at hot side of Tube W-6A. 100x.

The OD fireside cross-sections of tubes from the West Wall Tube 14 (W-14), Tube 30 (W-30) and Tube 47 (W-47) are illustrated in **Fig. 5, 6 and 7** respectively. All show ferrite and pearlite microstructures, with a decarburized layer, like new tube. All show normal fireside corrosion.

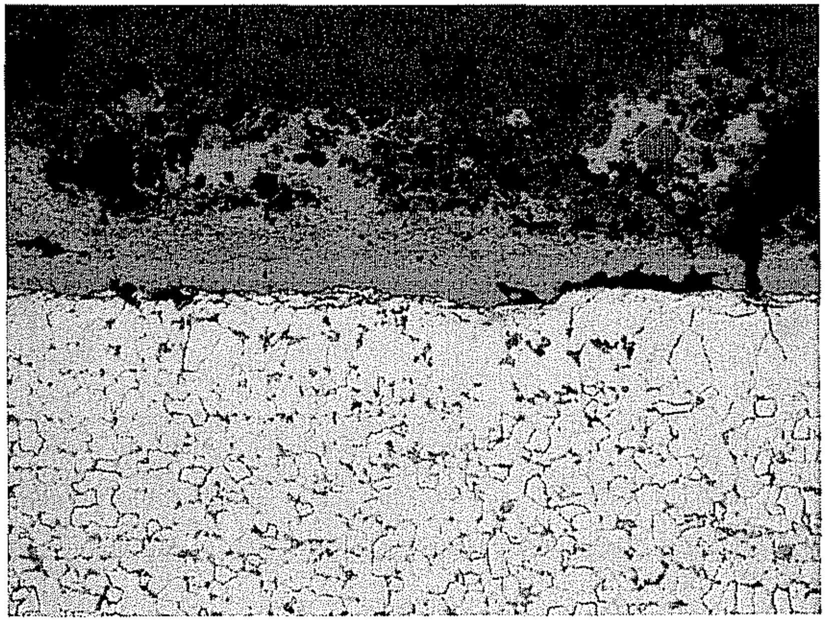


Figure 5. OD of W-14, hot side. 200x.

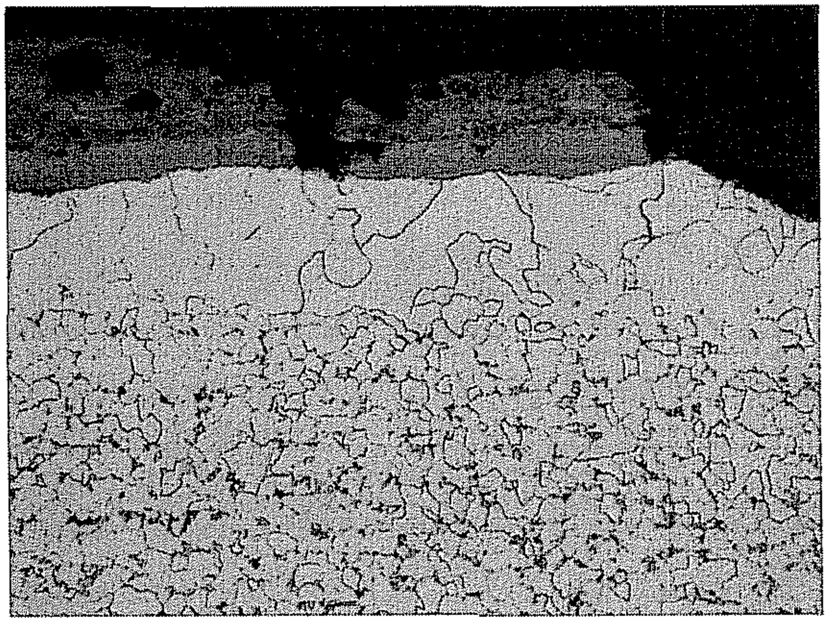


Figure 6. OD of W-30, hot side. 200x.

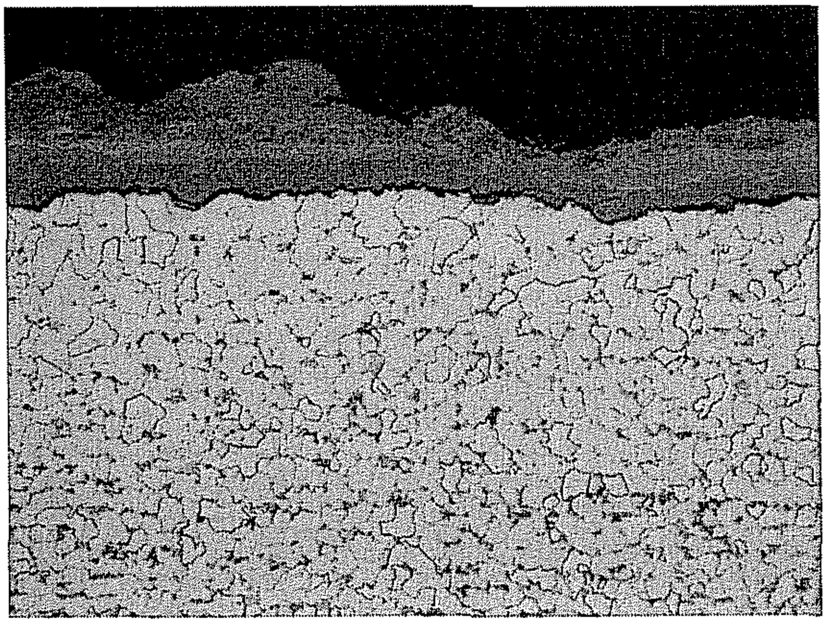


Figure 7. OD of W-47, hot side. 200x.

Ring samples were cut from each of the wall tubes to make dimensional and hardness measurements. **Figure 8** illustrates the rings, which show no visual evidence of significant thinning or distortion. The tubes were slightly larger measured front to back, **Table A**, suggesting some distortion. The hardness values for the tube averaged 63, 69, 68 and 70 Rockwell B (R_B), acceptable values for new tube. There was no significant difference in hardness between the hot side and the cold side of the tubes. If there had been significant overheating, the hot side might have been different.

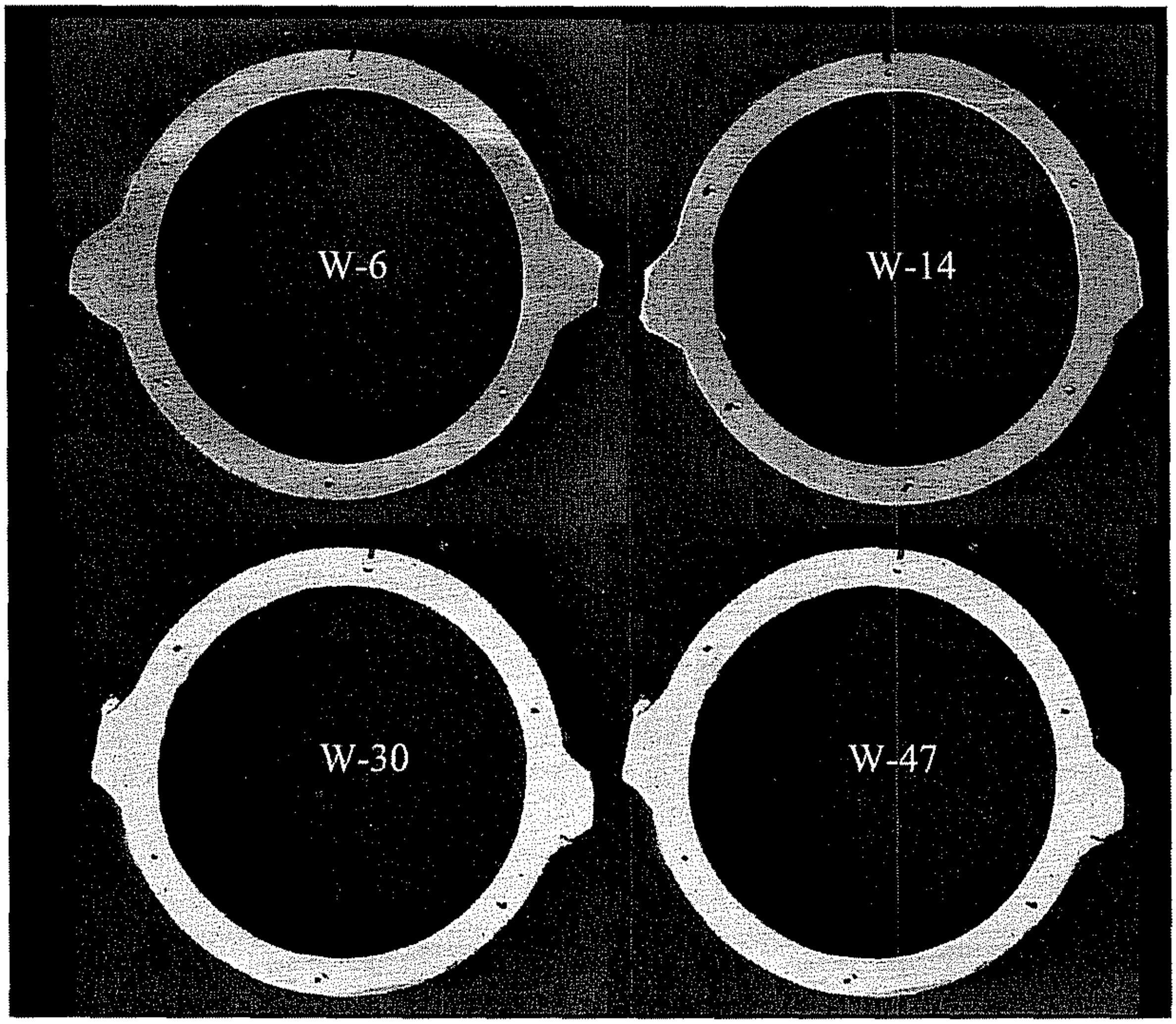


Figure 8. Sample rings removed from West Wall tubes.

Table A
West Wall Tubes - Dimensional and hardness measurements

Ring	Position	OD (inch)	ID (inch)	Wall (inch)	Hardness (R_B)
W-6-A	12:00	2.539	2.107	0.223	59
	2:00	2.504	2.075	0.214	63
	4:00	2.508	2.086	0.213	64
	6:00			0.209	61
	8:00			0.214	64
	10:00			0.215	67
					63 Average
W-14-A	12:00	2.533	2.112	0.208	66
	2:00	2.490	2.069	0.211	70
	4:00	2.497	2.077	0.211	69
	6:00			0.209	67
	8:00			0.215	69
	10:00			0.212	70
					69 Average
W-30-A	12:00	2.518	2.096	0.213	66
	2:00	2.492	2.069	0.211	69
	4:00	2.501	2.075	0.210	70
	6:00			0.210	70
	8:00			0.209	62
	10:00			0.222	70
					68 Average
W-47-A	12:00	2.516	2.092	0.211	71
	2:00	2.493	2.071	0.209	69
	4:00	2.496	2.067	0.210	71
	6:00			0.218	70
	8:00			0.213	70
	10:00			0.218	69
					70 Average

East Waterwall tubes

Four tube samples, removed from the East Waterwall for condition assessment are shown in **Fig. 9**. The tubes were generally clean with no evidence of damage or overheating. The inside of the tubes were clean.

E-6A | E-14A | E-27A | E-41A

Figure 9. As-received tubes from East wall.

The cross-section at the surface of East Wall Tube 6, **Fig. 10**, shows ferrite and pearlite microstructure, and a decarburized layer at the surface. The same structure was found on the cold side of the tube. At the mid-wall, **Fig. 11**, the pearlite and ferrite were present in a banded structure, and this was common to all the wall tubes.

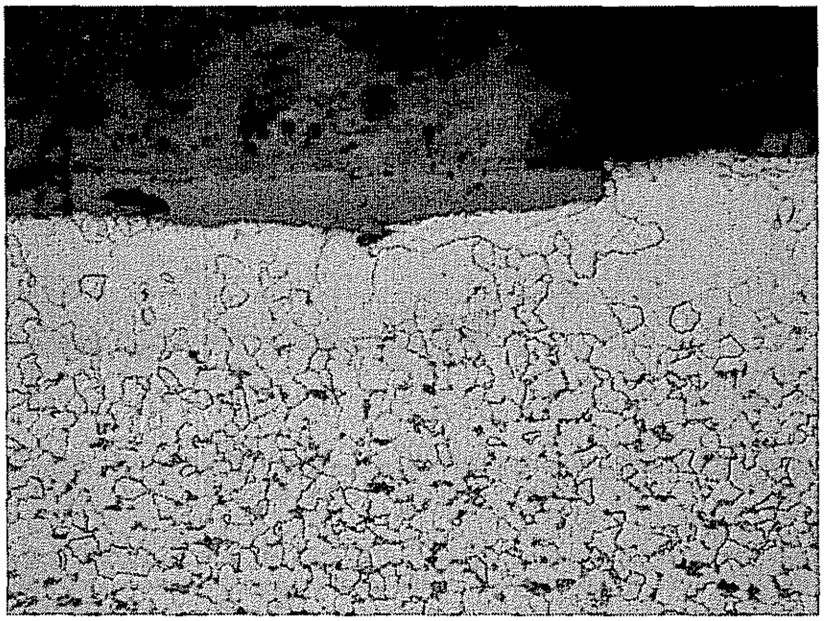


Figure 10. Tube E-6 OD on the hot side. Decarburized surface layer. 200x.

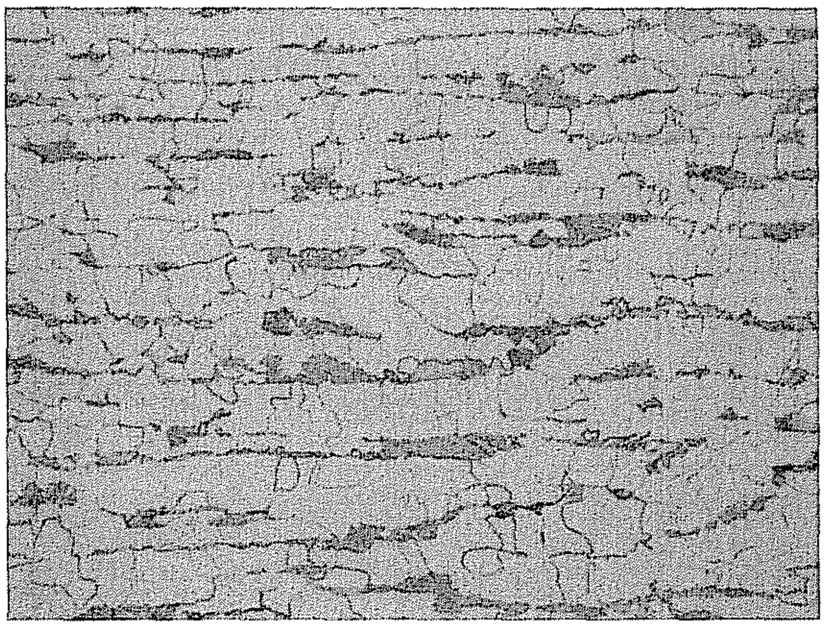


Figure 11. Typical pearlite and ferrite mid-wall microstructure at hot side of Tube E-6, and common in all East Wall tubes. 400x.

The fireside surface cross-section of East Wall Tube 14 is illustrated in **Fig. 12**, again ferrite and pearlite with a decarburized layer on the surface, fairly thin here. **Figure 13** illustrates the decarburized layer and the typical ferrite and pearlite structure at the waterside surface.

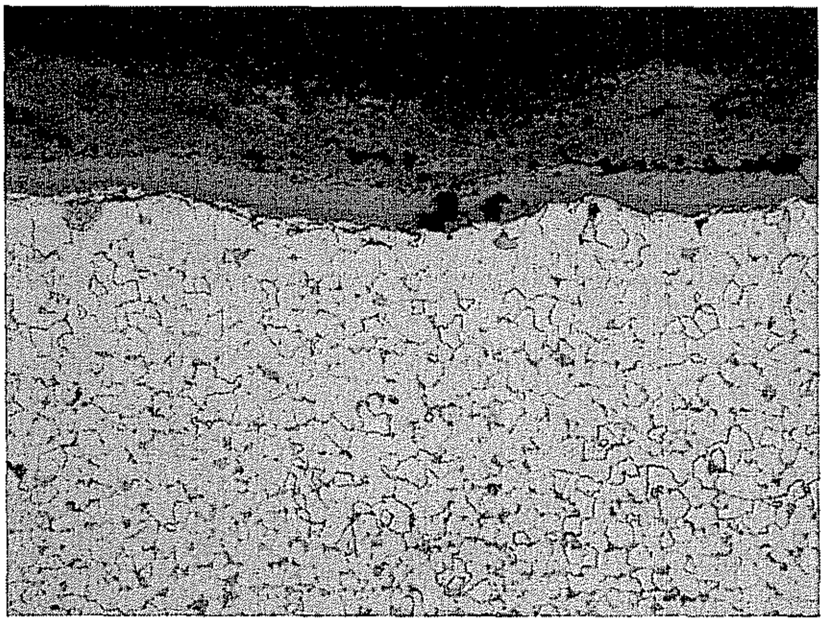


Figure 12. OD of Tube E-14, hot side. 200x.

Figure 13. Corrosion pits on ID of Tube E-14, hot side. 200x.

The OD cross-sections microstructures at the hot side of East Wall Tubes 27 and 41 are typical of new tube, **Fig. 14 and 15** respectively. There was no evidence of metallurgical degradation in the East Water Wall tubes.

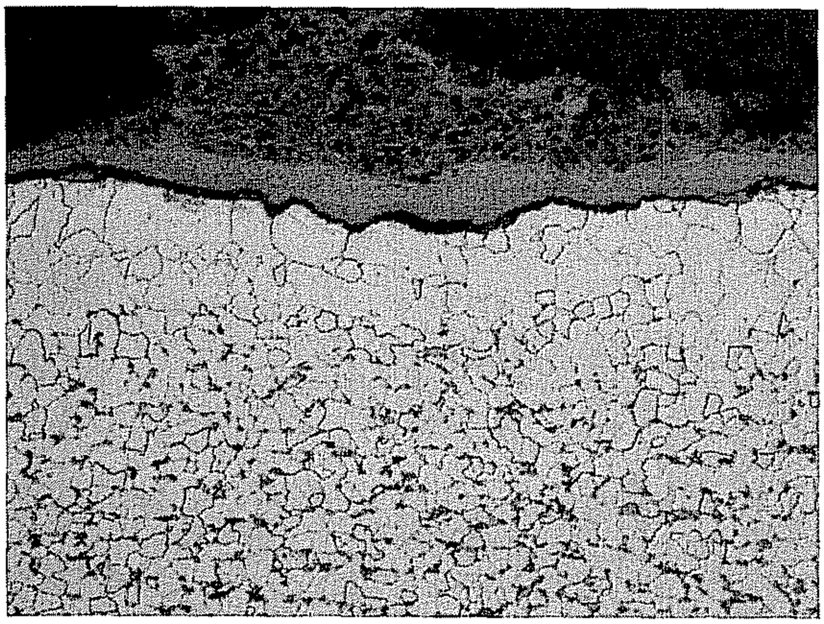


Figure 14. OD of Tube E-27, hot side. 200x.

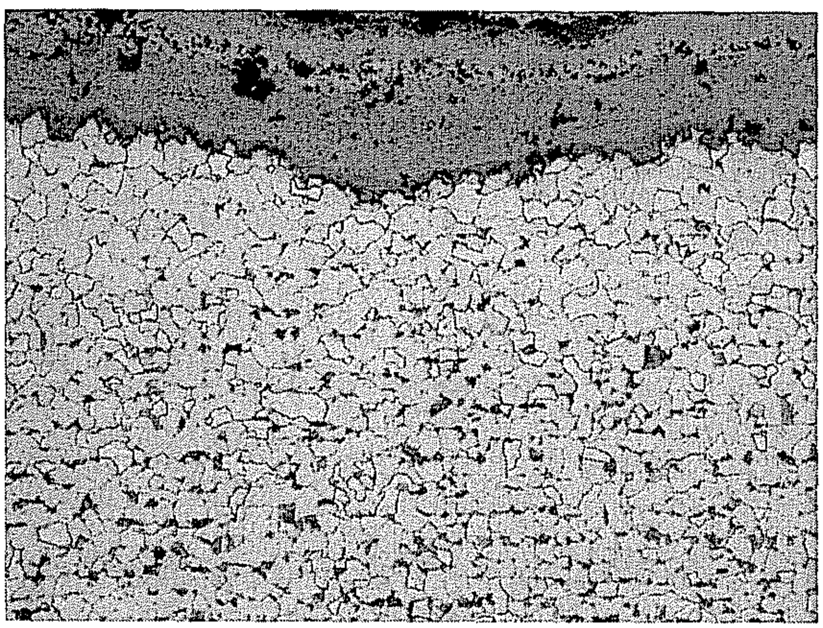


Figure 15. OD of Tube E-41, hot side. 200x.

Rings were cut from the sample tubes for dimensional and hardness measurements, **Fig. 16**. There was no visual evidence of thinning or distortion, although the measurements in **Table B** indicate the tubes were slightly wider from crown to crown than membrane to membrane, so the walls may be slightly deformed. Average hardnesses measuring 64, 65, 66 and 66 Rockwell B (R_B) were acceptable for this material. Cold side measurements (4, 6, 8 o'clock) were 66, 67, 67, and 68 compared with 62, 63, 65 and 64 for the hot side. These suggest that the hot side may have softened slightly, but this is not conclusive.

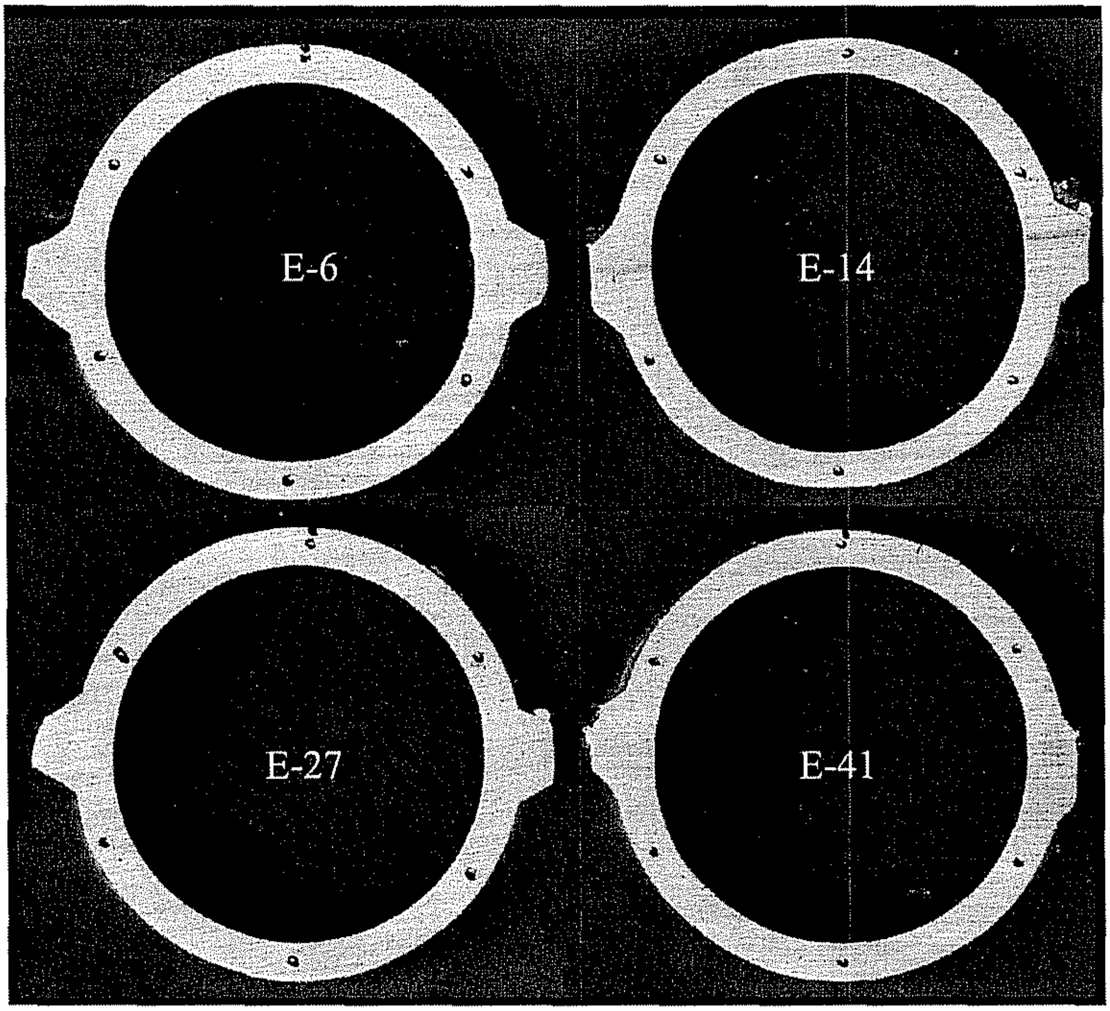


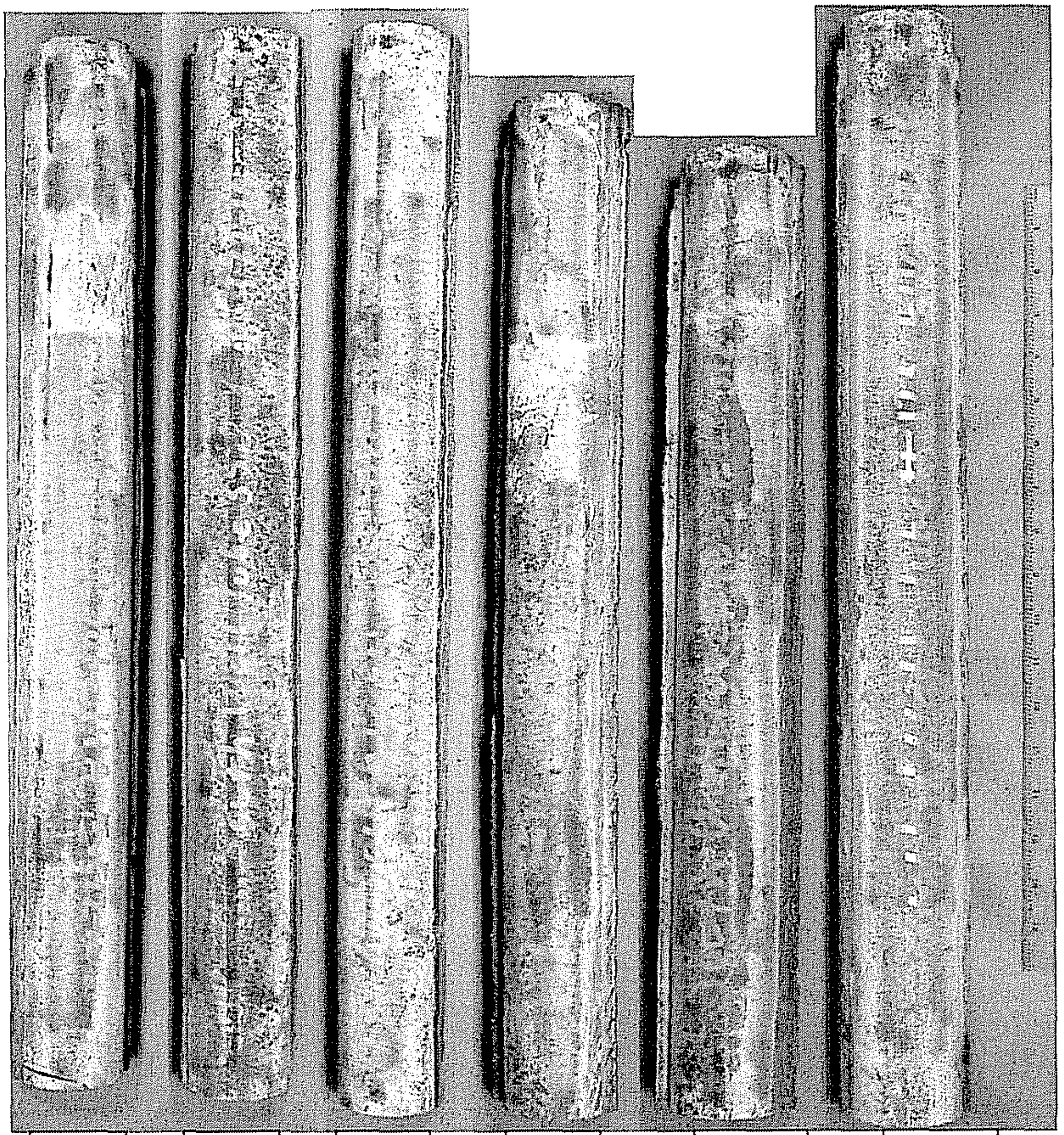
Figure 16. Removed rings from the East wall.

Table A
East Waterwall - Dimensional and hardness measurements

Ring	Position	OD (inch)	ID (inch)	Wall (inch)	Hardness (R_B)
E-6-A	12:00	2.524	2.099	0.211	62
	2:00	2.509	2.074	0.219	58
	4:00	2.508	2.079	0.216	66
	6:00			0.214	66
	8:00			0.218	65
	10:00			0.212	66
					64 Average
E-14-A	12:00	2.517	2.106	0.205	66
	2:00	2.513	2.091	0.209	62
	4:00	2.511	2.097	0.208	66
	6:00			0.206	68
	8:00			0.211	68
	10:00			0.206	62
					65 Average
E-27-A	12:00	2.519	2.090	0.216	67
	2:00	2.498	2.072	0.209	59
	4:00	2.504	2.078	0.210	65
	6:00			0.212	69
	8:00			0.215	68
	10:00			0.213	69
					66 Average
E-41-A	12:00	2.507	2.088	0.206	60
	2:00	2.500	2.078	0.208	71
	4:00	2.491	2.077	0.209	69
	6:00			0.214	67
	8:00			0.213	68
	10:00			0.202	61
					66 Average

South Waterwall tubes

Six tube samples, removed from the South Water Wall for condition assessment, are shown in **Fig. 17**. There was no visible evidence of surface damage or overheat. The inside of the tubes was clean.



S-14 S-35 S-51 S-65 S-103 S-123

Figure 17. As-received tubes from South Waterwall.

The cross-section at the surface of South Waterwall Tube 14, **Fig. 18**, shows a banded ferrite and pearlite microstructure, with a decarburized layer, seen in all the tubes. The decarburized layer was also observed on the ID, **Fig. 19**, and was seen on all the South Wall tubes. Some waterside pitting is also seen in **Fig. 19**.

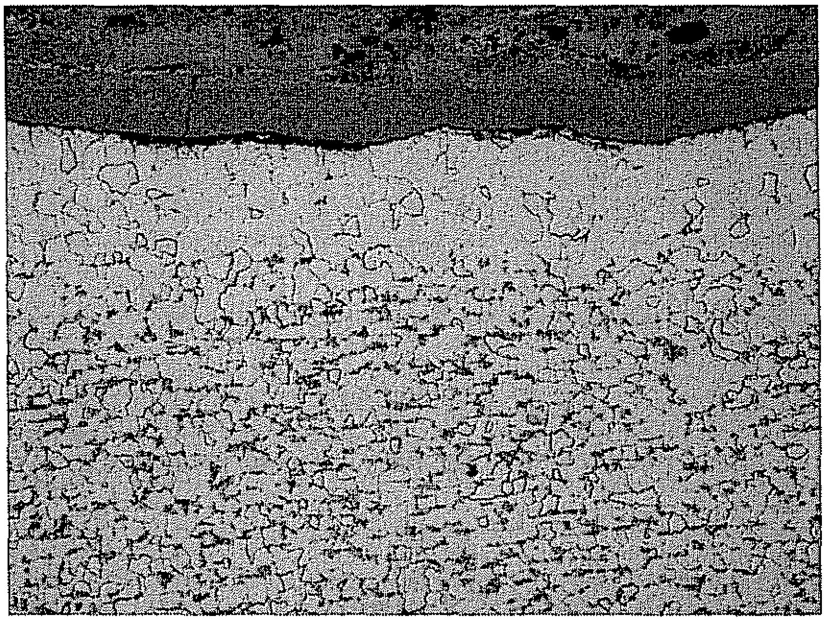


Figure 18. Tube S-14 hot side OD. 200x.

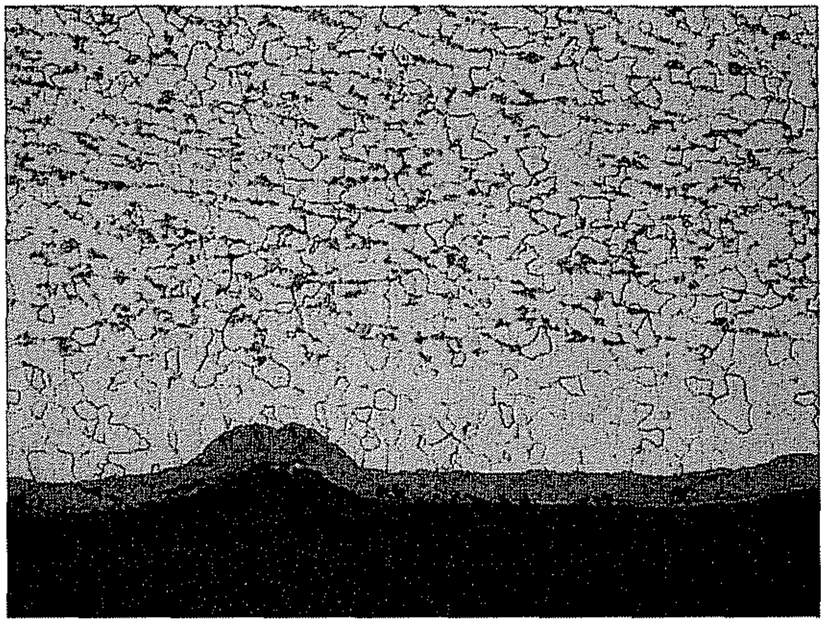


Figure 19. Tube S-14 hot side ID corrosion pit. 200x.

Figures 20 through 24 show the microstructure at the fireside OD of Tubes 35, 51, 103 and 123, all with ferrite and pearlite microstructures with a decarburized surface layer. None of them showed any evidence of overheating. **Figure 25** illustrates, again, some minor waterside corrosion.

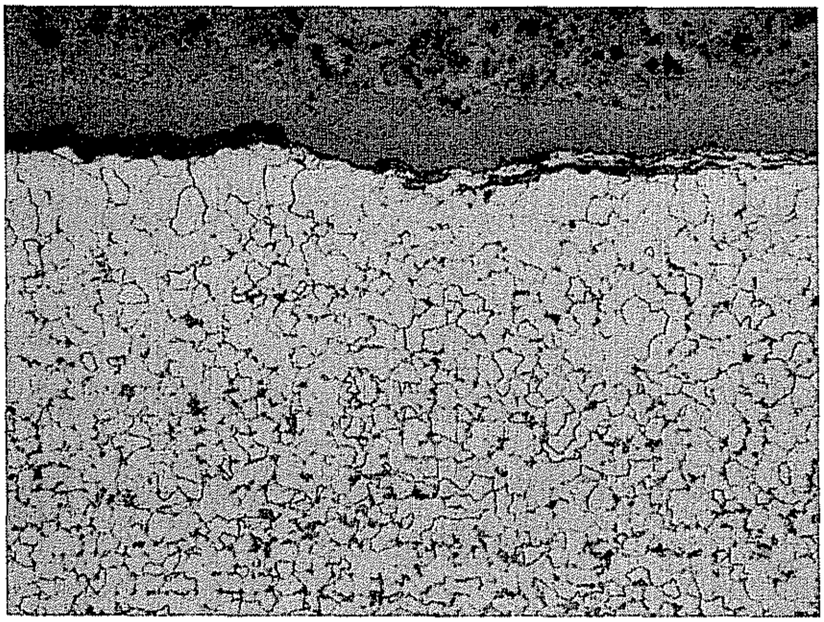


Figure 20. Tube S-35 hot side OD. 200x.

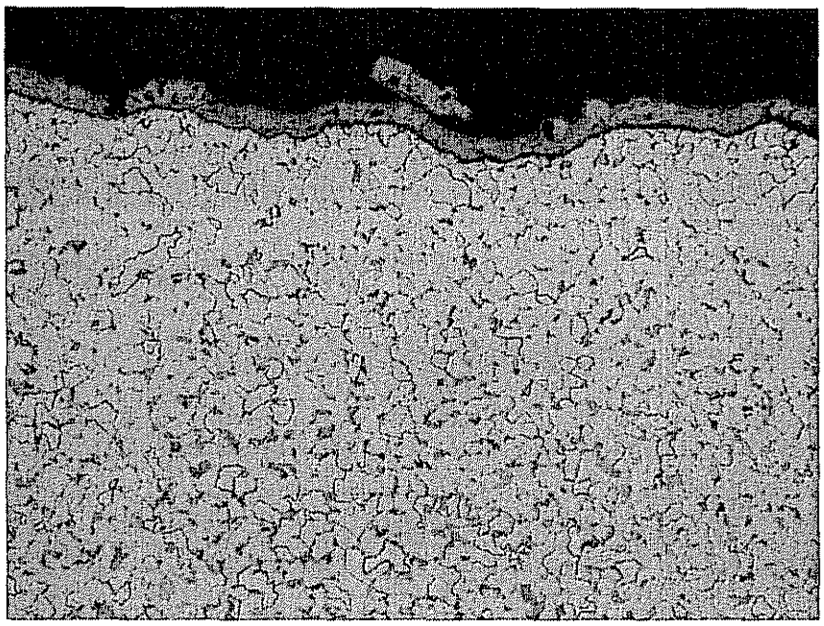


Figure 21. Tube S-51 hot side OD. 200x.

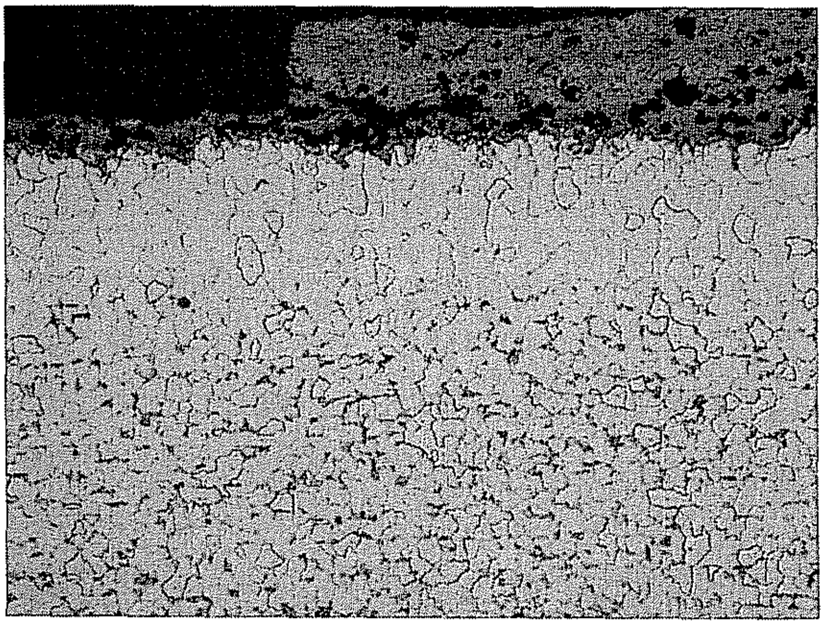


Figure 22. Tube S-65 hot side OD. 200x.

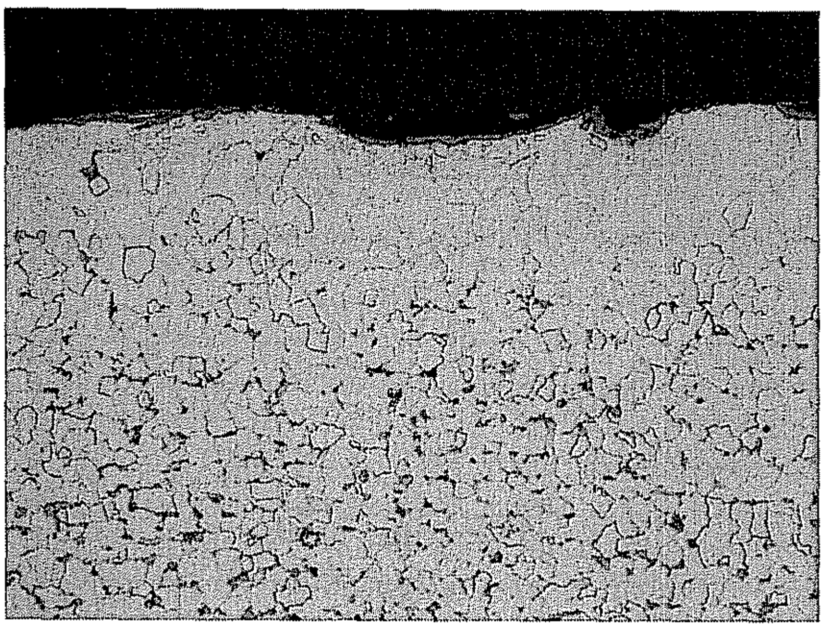


Figure 23. Tube S-103 hot side OD. 200x.

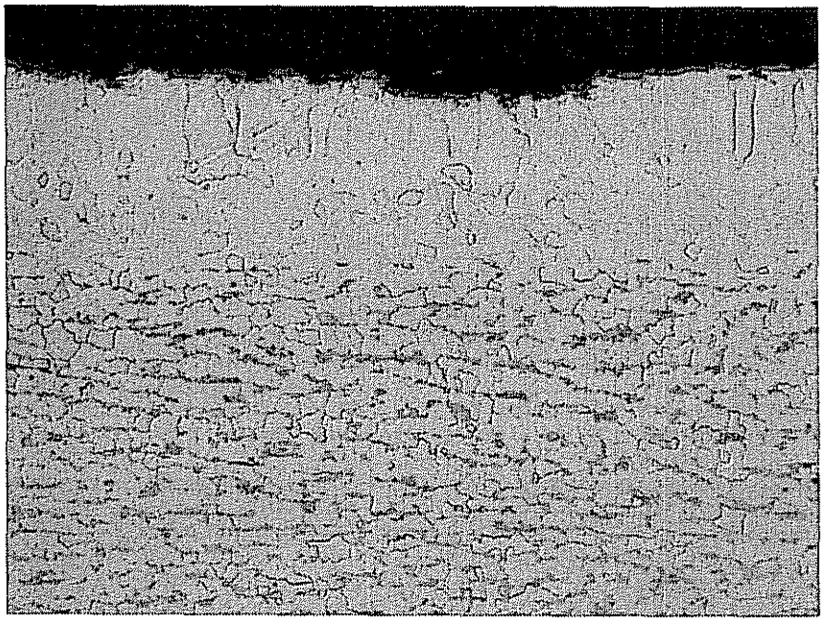


Figure 24. Tube S-123 hot side OD. 200x.

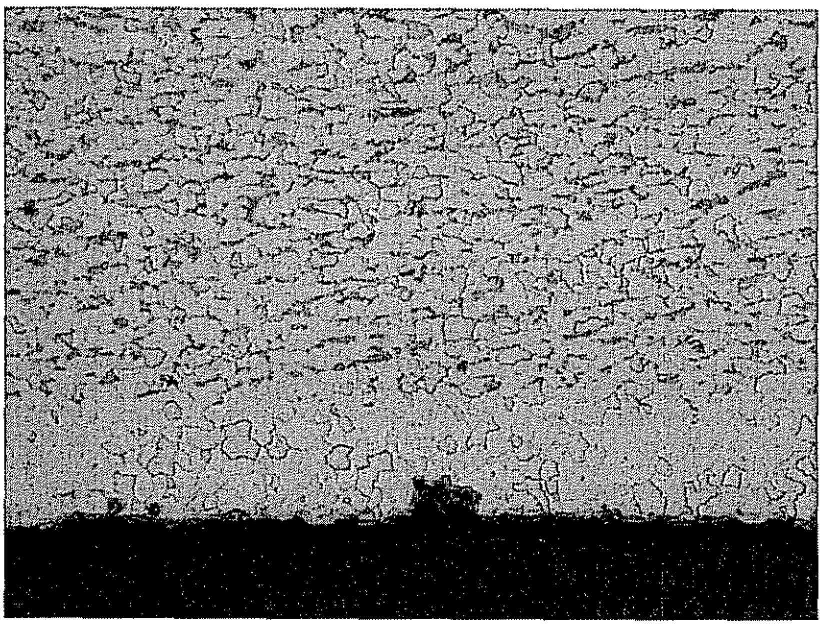


Figure 25. Tube S-123 hot side ID. 200x.

Ring samples from the South Waterwall are shown in **Fig. 26**. There was no visual evidence of distortion, although the tubes measured a larger diameter from crown to crown compared to membrane to membrane, **Table C,** like all the tubes measured here. No significant thinning was measured. The tube hardnesses averaged 65, 65, 62, 65, and 67 R_B, acceptable for this tube. There was not much difference in hardness when comparing the cold side with the hot side.

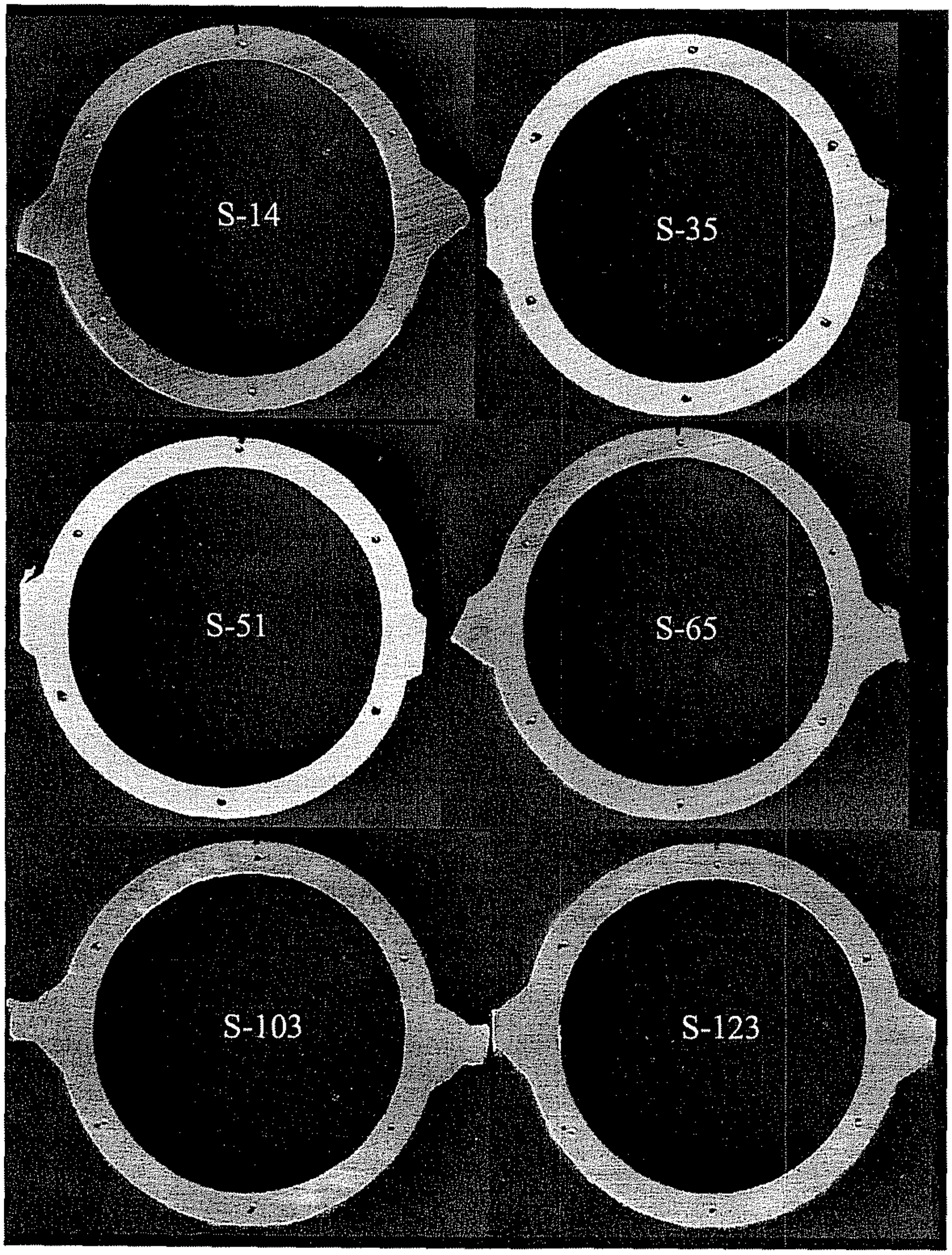


Figure 26. Ring samples removed from South Wall tubes.

Table C
South Wall Dimensional and hardness measurements

Ring	Position	OD (inch)	ID (inch)	Wall (inch)	Hardness (R_B)
S-14-A	12:00	2.544	2.088	0.221	65
	2:00	2.495	2.033	0.233	65
	4:00	2.504	2.058	0.227	66
	6:00			0.232	66
	8:00			0.230	65
	10:00			0.219	65
					65 Average
S-35-A	12:00	2.534	2.075	0.230	62
	2:00	2.498	2.040	0.229	65
	4:00	2.505	2.047	0.231	64
	6:00			0.228	67
	8:00			0.230	64
	10:00			0.228	66
					65 Average
S-51-A	12:00	2.535	2.117	0.205	54
	2:00	2.498	2.077	0.209	66
	4:00	2.497	2.070	0.215	61
	6:00			0.213	66
	8:00			0.209	65
	10:00			0.211	58
					62 Average
S-65-A	12:00	2.595	2.183	0.197	59
	2:00	2.514	2.087	0.212	66
	4:00	2.514	2.082	0.215	67
	6:00			0.216	65
	8:00			0.217	67
	10:00			0.214	68
					65 Average
S-123-A	12:00	2.538	2.082	0.230	65
	2:00	2.499	2.045	0.232	68
	4:00	2.524	2.060	0.228	65
	6:00			0.227	69
	8:00			0.226	66
	10:00			0.227	67
					67 Average
S-103-A	12:00	2.541	2.097	0.219	62
	2:00	2.489	2.057	0.217	67
	4:00	2.504	2.067	0.224	63
	6:00			0.221	60
	8:00			0.215	63
	10:00			0.216	67
					64 Average

Deposit Weight Density Measurements

Deposit weight density was measured on a tube from each wall with the following results:

1. East Wall Tube 6A Hot Side – 8 g/ft^2
2. East Wall Tube 6A Cold Side – 8 g/ft^2
3. South Wall Tube 14A Hot Side – 16 g/ft^2
4. South Wall Tube 14A Cold Side – 8 g/ft^2
5. West Wall Tube 47A Hot Side – 8 g/ft^2
6. West Wall Tube 47A Cold Side – 8 g/ft^2

All of these results indicate that the boiler is clean.

ATTACHMENT 5

RILEY-STOKER H-1 BOILER INSPECTION 12-28-1984

BIG RIVERS
ELECTRIC CORPORATION

INTEROFFICE CORRESPONDENCE

TO: *Earl Millspaugh*

FROM: *Lee Morgan* alm.

RE: *H-1 BOILER INSPECTION*

DATE: *December 28, 1984*

COPIES TO: *Richard Greenwell*
Kerry Hay
Darrell Anderson

The purpose of the inspection on the H-1 Boiler was to determine the damage that resulted from overheating of the Boiler on November 12, 1984. The inspection dates were from December 17th through December 21st, 1984.

All four walls were inspected by Riley Stoker's Engineer; Jim Banta of Continental Insurance; myself; Kerry Hay; and several other Big Rivers' employees. It was agreed to take five tube samples out of the Boiler Walls that appeared to be in the worst areas. These were: one tube out of the north Wall located at an elevation of 187'2" being the 17th tube from the N/W corner; one tube out of the east wall located at an elevation of 498'0" being the 45th tube from the N/E corner; one tube out of the south wall located at an elevation of 508'6" being the 34th tube from the S/E corner; and two tubes out of the west wall located at an elevation of 487'2" being the 32nd and 42nd tube from the N/E corner. See the attached sheet for all samples.

We also took a U.T. reading on all four Walls located at the same elevation that the tube samples were taken. See the attached sheet for tube sample thickness.

We dropped a plumb bob and took Wall deflection in the same areas as samples were taken which is given on the same sheet as the tube samples. Tube samples will be sent to both Riley Stoker and D. N. French for metal analyses and thickness testing. The results will be forwarded to you when we receive them.

There were several pictures taken by both Riley, Ed Chisholm, and R. D. Smith which are available if you need them.

Riley inspected the Back Pass of the Boiler; the outside structure and Backstay. They reported that they saw no problems other than what was visible on the inside. Mr. Richard Bubier, Riley's Engineer, said he would be sending us his report after seeing the tube analyses but, at present, saw no problems if the tube structures are not damaged.

The Wall Sootblowers were inspected and re-set to allow for wall deflection as necessary. As can be seen by the U.T. testing, we do have some thinning of some of the wall tubes - the thinnest being on one tube .160 whereas the original should have been .203 . Mr. Ralph Pentecost and Richard Bubier of Riley Stoker; Mr. Jim Banta with Continental Insurance; and myself all agreed there is no danger or immediate problems with continued running of the Unit at its fullest operating load at the present time or in the near future.

I feel that we did a good inspection and, when we see the tube analyses, we can determine the amount of shortened Boiler life due to the overheating.

ALM/lph

RILEY RILEY STOKER CORPORATION
POST OFFICE BOX 547, WORCESTER, MASS. 01613
A Subsidiary of United States Riley Corporation

H-1 OUTAGE
BOILER INSPECTION
11-17-84

CONSTRUCTION DIVISION

EAST WALL

El. 498'-0", From North to South

A 20 inch Dutchman was placed on the 45th tube. On the 43rd tube, the wall deflected outward 2 1/8". (On the East Wall all deflections face outwards, except approximately 18" at each end of the wall. The deflections began at El. 492'-0" and continued to El. 503'-0".

At elevation level 487'-2", a deflection of 3 1/2" outward occurred at approximately 18" from the North Side and continued over two-thirds of the way toward the South Wall. The span of the deflection was limited to approximately 10 feet in height.

WEST WALL

SA-210-203 WALL TUBE

From North to South

A 20 inch Dutchman was installed at El. 487'-2" on the 32nd tube and on the 42nd tube. These sample tubes and the deflections are even with the center line on the top burner.

The 17th tube deflected inwards 1 5/8".

On the 26th tube, the wall deflected outward 3 1/4". This was the biggest deflection in the entire boiler.

The 30th tube, (Located - Southside West Wall), Deflected outward 2 3/8".

At elevation level 498'-0". The 17th tube, LOOKING FROM SOUTH TO NORTH. (Southside West Wall), deflected outward 1 3/4".

NORTH WALL

From West to East

A 20 inch Dutchman was installed at El. 187'-2", on the 17th tube; and the deflection was outward at 2 1/2". This deflection however, is limited to a approximate 10 foot area.

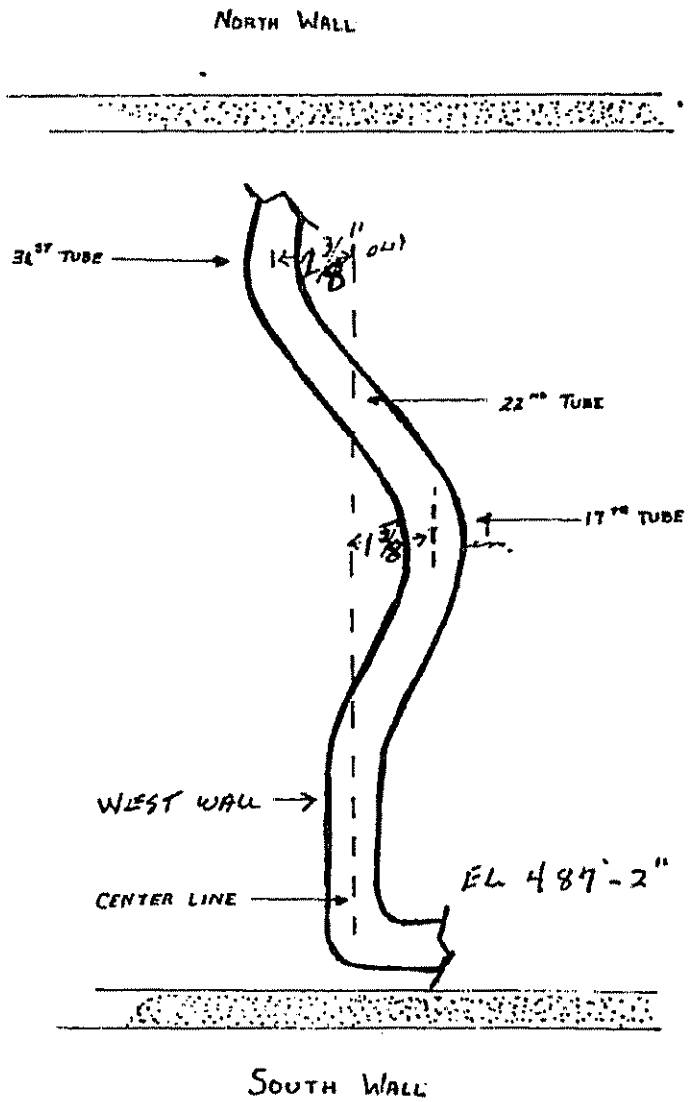
As well, the 17th tube at elevation 479'-2", is deflected outward, the distance of 2 5/8". Again, this deflection is confined into a limited area of approximately 10 foot area.

SOUTH WALL

From East to West

A 20" Dutchman was installed at El. 508'-6", on the 34th tube, which had a deflection outward of 2". This deflection started at approximately 18" on the East Wall and continued unformily to approximately 18" from the West Wall.

Soot blowers 2, 3 and 4 are located at center of this deflection. When unit is turned on line, these units must be relocated.


NORTH WALL
31ST TUBE
$1\frac{3}{8}$" OUT
22ND TUBE
17TH TUBE
$1\frac{3}{8}$"
WEST WALL
CENTER LINE
EL 487'-2"
SOUTH WALL

PLAN VIEW

North
East wall start ⇒ south #3 = .196, #5 = .200
7 = .212, 9 = .206, 11 = .201, 13 = .208 15 - .204, 17 = .20.
19 = .207, 21 = .202, 23 = .196, 25 = .208 27 = .201, 29 = .202,
31 = .201, 33 = .183, 35 = .204 37 = .202, 39 = .197 41 = .182
53 43 = .182, 45 = .189, 47 = .188, 49 = .182, 51 = .186, 53 = .160,
55 = .201, 57 = .195, 59 = .198, 61 = .196, 63 = .197, 65 = .192
67 = .199, 69 = .200, 71 = .205 73 = .196 75 = .200 79 = .198
81 = .202 83 = .200, 85 = .179, 87 = .193, 89 = .192
91 = .194, 93 = .202, 95 = .196 97 = .200, 99 = .197, 101 = .200,
103 = .200, 105 = .201, 107 = .206, 109 = .202, 111 = .206
113 = .200, 115 = .200, 117 = .180 119 = .202 121 = .195
123 = .199 125 = .201 127 = .206 129 = .207 131 = .206
133 = .200 135 = .200
#33 & #52 Rupture

TOP = .191
51 = .194
BTM m .190

TOP = .194
52 = .190
BTM m = .218

TOP = .165
53 = .173
BTM m .163
4'
.178

#33 = .215
BTM Dutchman

#33 TOP .162

#33 = .192 BTM

10 ft down N ⇒ S #1 = .208, #6 = .205, #11 = .206 #16 = .210
#21 = .209 #26 = .212 #31 = .200, #36 = .200, #40 = .190, #46 = .202
#50 = .184, #55 = .200, #60 = .201 #65 = .201 70 = .210
75 = .206, 80 = .208, 85 = .183 #90 = .196, #95 = .204 100 = .206
105 = .205 110 = .210, 115 = .208, #120 = .201 125 = .202 #130 = .202
135 = .207 -

South wall E-W
#3=.218, #8=.217 #13=.218 #18=.201 #23=.202
28=.208, 33=.218, 38=.204, 43=.206, 48=.208,
53=.211, 58=.207 63=.210 68=.197, 73=.206,
78=.208, 83=.211 88=.206, 93=.212

8' down #3=.204, #8=.200, #13=.190, #18=.190 23=.206
28=.214, 33=.210 38=.198, 43=.204, 48=.207, 53=.207
58=.202 63=.208 68.213 73=.212 78=.200 83=.208
88=.214 93=.208

#2 #3 #4

#8 X #9 #10

#15 #16 #17

#21 #22 #23

#14?

Sample

North Wall

W TO E #4 = .190 #9 = .190 #14 = 180 #19 = .170

#24 = 172 #50 = 196 #55 = 206 #82 = .206

#87 = .212 #114 = .214, #119 = .211. #124 = .209

Six ft higher

#11 = .188	#16 = .240	21 = .238	26 .243
31 = .214	36 = .231	41 = .248	46 .242
51 = .214	56 = 236	61 = 252	66 .247
71 = .236	76 = 243	81 = 240	86 = .212
91 .247	96 242	101 241	106 = .216
111 = .254	116 = .246		

Runtime 54 | Sample 53 | 10/43 | 10/33 |

West Wall N to S

#2=.206, #7=.200, #12=.207, #17=.208, #22.217

27=.224, 32=.213, 37=213, 42=.207, #47.200

52.195, 57.211, 62=.214, 67 213, 72.208

77 214, 82 209, <u>87=177</u>, 92 202, 97.=200

102=216, 107=208, 112=208, 117=209, 122=<u>.184</u>

127=.192, 132=.195, 137=211,

01-00-00-00-00

HENDERSON I OUTAGE

DAMAGE ONLY

1.	Insulation 3" x 4" x 48" Delta Board x 24	$122.88
2.	Lagging (Same re-used old material)	--
3.	Insulation and Lagging (Labor) 36 Hours	412.64
4.	Tube Cost	568.00
5.	Soot Blower Inspection (B.R. Labor)	232.56
6.	Soot Blower Adjustment (B.R. Labor)	118.80
7.	Boiler Inspection (B.R. Labor)	68.00
8.	Tube Sample Analysis (Cost)	—
9.	Riley Boiler	
	A. Thickness Testing, Welding (Labor)	11,880.00
	B. Scaffold and Equipment	—
	C. Materials (Rods, etc.)	—
	D. Outside Specialist	--
10.	Thickness Testing (B.R. Labor)	45.00
11.	Misc. Labor (Chemist, Engineers, Prod. Supt. Maint. Supt., etc.)	255.00

Henderson I

OFF: 10:31 P.M. on 12-15-84

ON: 11:04 P.M. on 12-21-84

<u>TUBE REPAIRS</u>

UNIT H-1

DATE 11/24/84

CONTRACTOR OR FOREMAN Riley Stocker Corp.

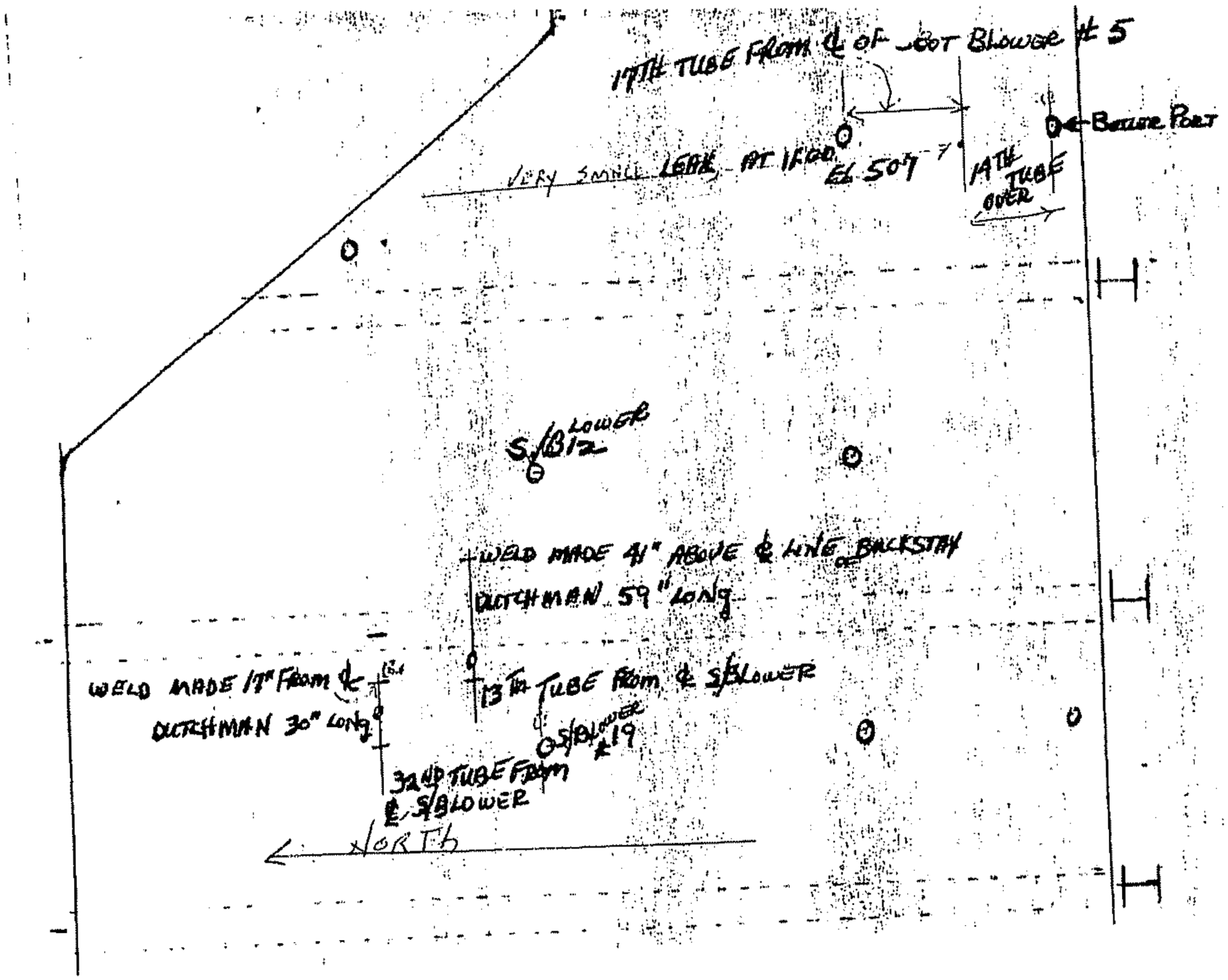
LOCATION

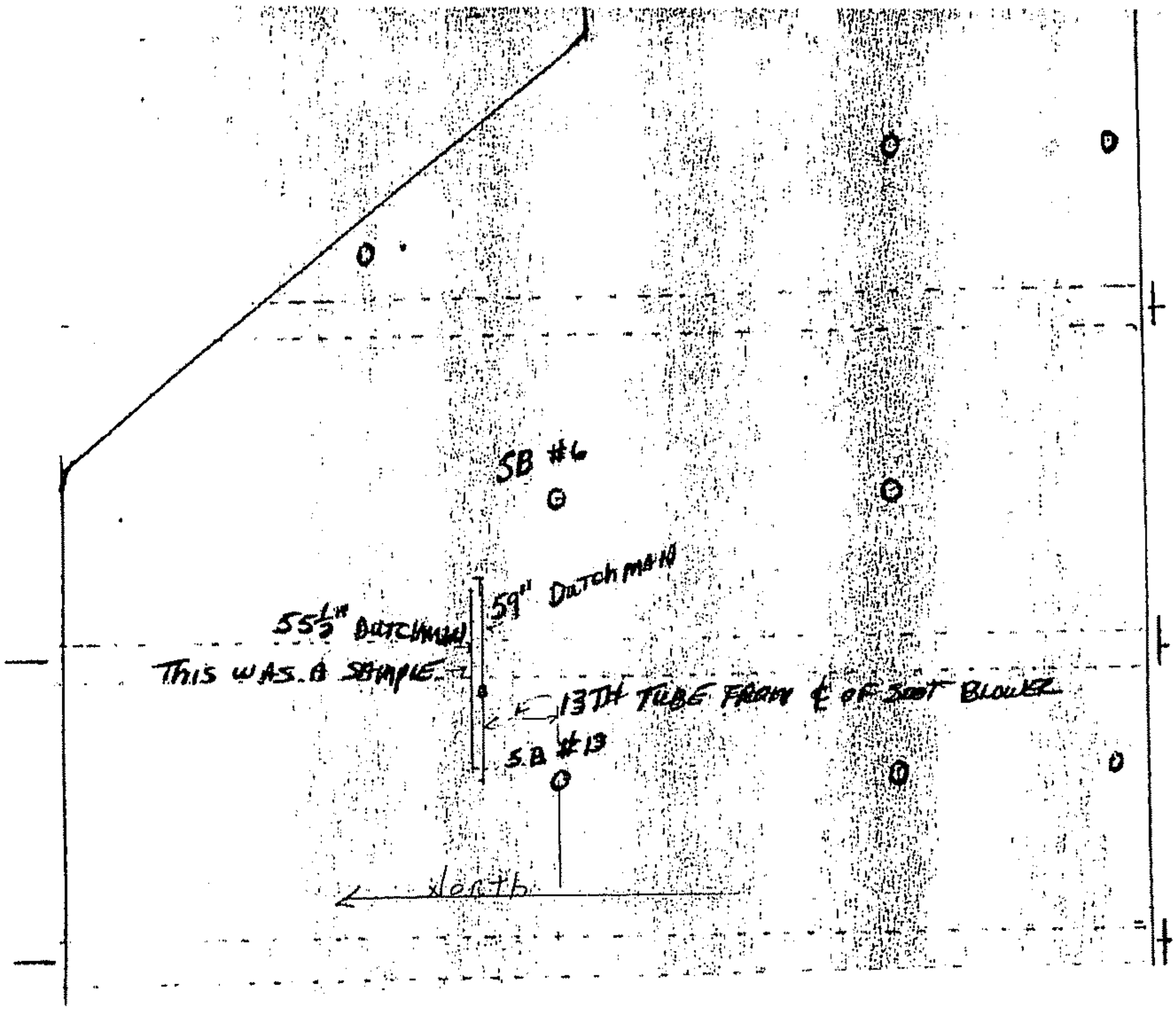
CAUSE

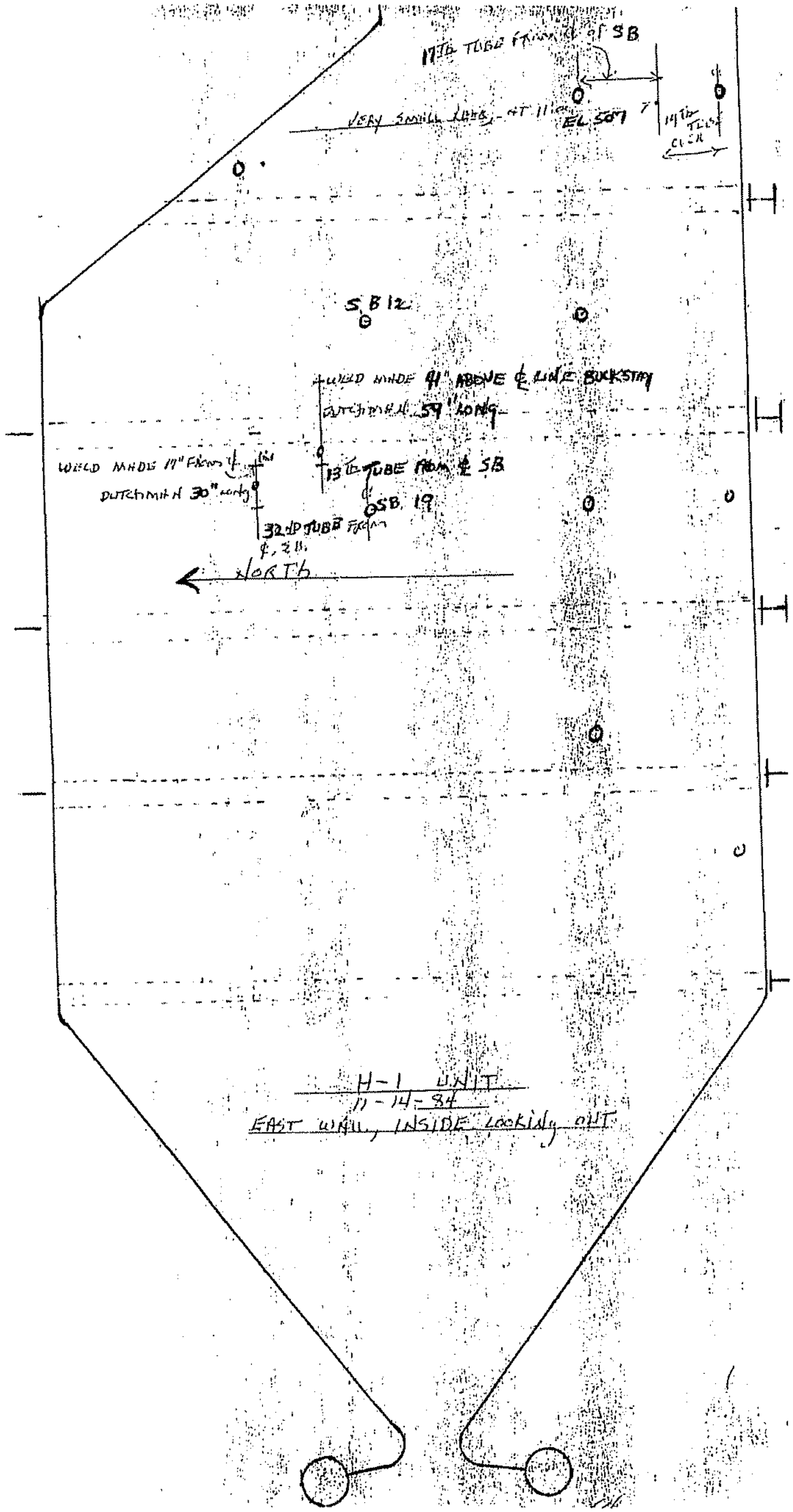
WELDERS AND I.D. NOS. Riley Stoker Certified Welders

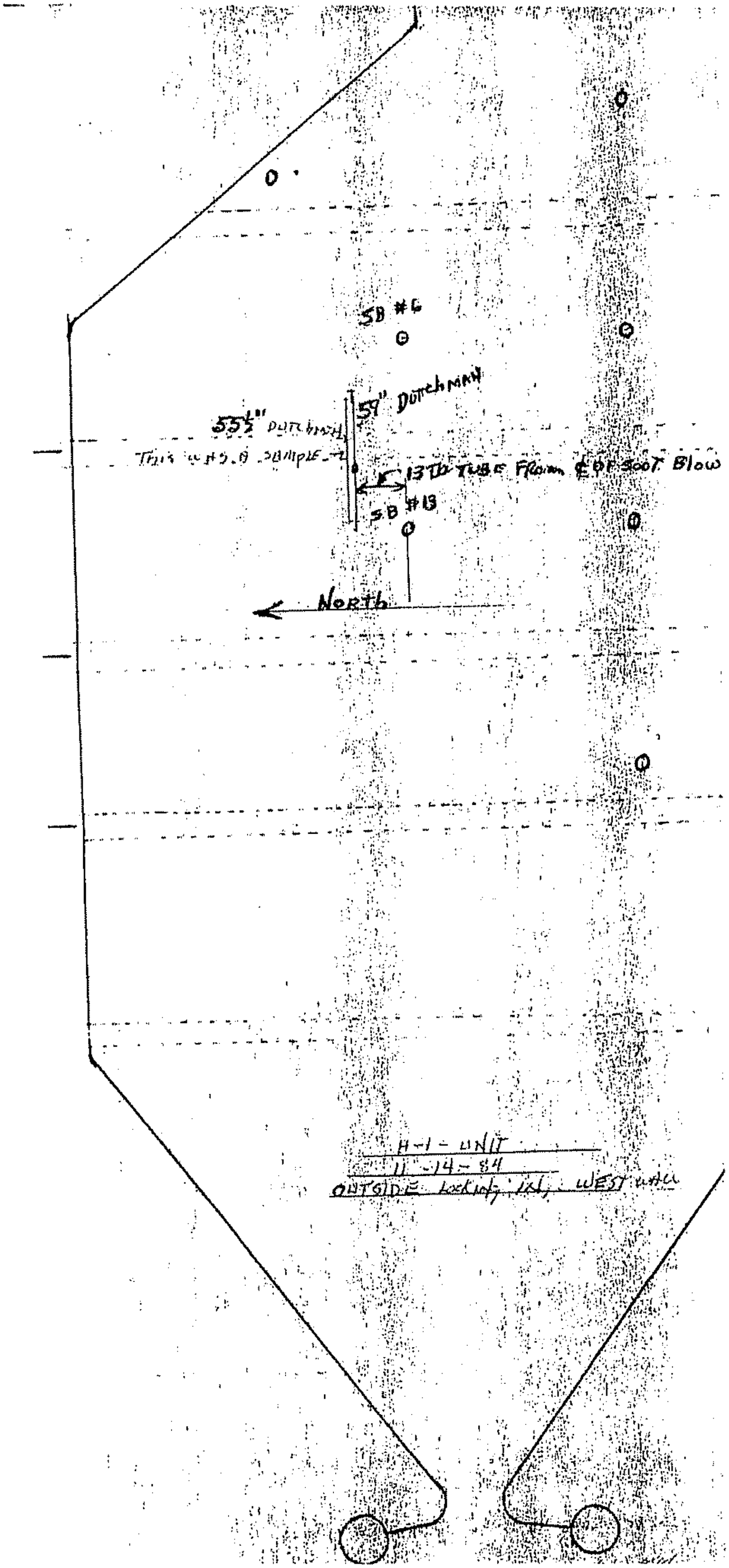
DESCRIPTION OF WORK On November 12, 1984, (3) Water Wall Tubes ruptured, (1) on West Wall and (2) on East Wall. On the West Wall, 13th tube North of center line of # 13 Wall Sootblower had thin lip rupture. The East Wall,(2) tubes ruptured and one had a pin hole, (found after hydroing). The 13th and 32nd tubes, North of center line of # 19 Wall Sootblower had thin lip ruptures, 17th tube, South of center line of # 5 Sootblower has a pin hole at approximatley 11:00 o'clock. Boilermakers installed a 59" Dutchman to replace ruptured tube on West Wall and removed a tube sample from the 14th tube, North of center line of # 13 Wall Sootblower and installed a 55 1/2" Dutchman in its place. Installed a 59" Dutchman for the 13th tube & a 30" Dutchman for # 32 tube, North of center line of # 19 Wall Sootblower and pad welded pin hole on # 17 tube, South of center line of # 5 Wall Sootblower, all on East Wall.

FUTURE REPAIRS REQUIRED


17TH TUBE FROM ℄ OF SOOT BLOWER #5
BOILER PORT
VERY SMALL LEAK AT 1500 EL 507 7
14TH TUBE OVER
S/B12 LOWER
WELD MADE 41" ABOVE ℄ LINE BACKSTAY
DUTCHMAN 59" LONG
WELD MADE 17" FROM ℄
DUTCHMAN 30" LONG
13TH TUBE FROM ℄ S/BLOWER
S/BLOWER #19
32ND TUBE FROM ℄ S/BLOWER
NORTH


SB #6
59" Dutchman
55½" Dutchman
This was a Sample
13TH TUBE FROM ℄ OF SOOT BLOWER
S.B #13
North


17th TUBE FROM ℄ of SB
VERY SMALL LEAK AT 11 o'c
EL 507
7"
14th TUBE CLEAR
SB 12
WELD MADE 41" ABOVE ℄ LINE BUCKSTAY
DUTCHMAN 59" LONG
WELD MADE 17" FROM ℄
DUTCHMAN 30" LONG
13th TUBE FROM ℄ SB
SB 19
32nd TUBE FROM ℄ SB
NORTH
H-1 UNIT
11-14-84
EAST WALL, INSIDE LOOKING OUT


SB #6
59" DUTCHMAN
55½" DUTCHMAN
This WAS A SAMPLE
13TH TUBE FROM ℄ OF SOOT BLOW
SB #13
North
H-1 - UNIT
11-14-84
OUTSIDE Looking In, WEST WALL

ATTACHMENT 6

SEBREE STATION ENERGY REPORTS FOR EFOR 2005-2007

HMP'L 1 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	YTD
EFOR, %	9.98	13.09	0.00	4.10	0.00	0.00	0.00	2.10	0.00	15.88	10.14	13.52	5.14
EFOR KPI Target, %	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
EAF, %	90.02	86.91	100.00	95.90	100.00	100.00	100.00	97.90	93.10	32.73	89.79	82.60	89.03
EAF KPI Target, %	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	86.60	35.90	92.80	92.80	87.50
Forced Outage Hours	65.50	82.10	0.00	26.90	0.00	0.00	0.00	15.00	0.00	23.30	69.40	72.60	354.80
Unplanned(4) Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.60	32.60
Planned Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.70	454.30	0.00	0.00	504.00
Planned Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unplanned(4) Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	82.5	115.0	227.5
Forced Derating MWH	1440.0	965.5	0.0	432.5	0.0	0.0	0.0	100.0	0.0	3747.5	617.0	3887.5	11,190.0
Equivalent Derated Hours	8.73	5.85	0.00	2.62	0.00	0.00	0.00	0.61	0.00	22.89	4.24	24.26	69.20
Equiv. Forced Derated Hours	8.73	5.85	0.00	2.62	0.00	0.00	0.00	0.61	0.00	22.71	3.74	23.56	67.82
Forced Outage Rate, %	8.80	12.22	0.00	3.74	0.00	0.00	0.00	2.02	0.00	8.04	9.63	10.21	4.31
Availability Factor, %	91.20	87.78	100.00	96.26	100.00	100.00	100.00	97.98	93.10	35.81	90.37	85.86	89.82
Gross Capacity Factor, %	85.53	83.89	96.41	91.23	91.77	92.49	92.54	90.26	86.18	30.69	83.88	76.94	83.43
Gross Output Factor, %	93.79	95.57	96.41	94.77	91.77	92.49	92.54	92.12	92.57	85.70	92.82	89.61	92.88

HMP'L 2 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	YTD
EFOR, %	12.42	0.00	0.99	10.24	9.56	8.02	0.00	0.00	5.34	19.35	5.25	5.25	5.42
EFOR KPI Target, %	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
EAF, %	87.58	100.00	99.01	89.76	90.44	91.98	100.00	100.00	94.66	12.80	73.50	90.29	85.70
EAF KPI Target, %	91.70	91.70	91.70	91.70	91.70	91.70	91.70	91.70	91.70	5.30	91.70	91.70	88.20
Forced Outage Hours	83.50	0.00	6.70	69.90	69.10	54.10	0.00	0.00	36.50	21.80	14.90	5.10	361.60
Unplanned(4) Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.90	33.90
Planned Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	625.90	157.90	0.00	783.80
Planned Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	412.5	0.0	412.5
Unplanned(4) Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	202.5	175.0	377.5
Forced Derating MWH	1535.0	0.0	117.5	652.5	347.5	632.5	0.0	0.0	337.5	180.0	2526.5	5538.0	11,867.0
Equivalent Derated Hours	8.92	0.00	0.68	3.79	2.02	3.68	0.00	0.00	1.96	1.05	18.26	33.22	73.59
Equiv. Forced Derated Hours	8.92	0.00	0.68	3.79	2.02	3.68	0.00	0.00	1.96	1.05	14.69	32.20	68.99
Forced Outage Rate, %	11.22	0.00	0.90	9.71	9.29	7.51	0.00	0.00	5.07	18.46	2.65	0.72	4.55
Availability Factor, %	88.78	100.00	99.10	90.29	90.71	92.49	100.00	100.00	94.93	12.94	76.03	94.76	86.54
Gross Capacity Factor, %	79.19	89.65	89.51	80.99	78.82	80.86	88.10	87.76	82.15	11.23	63.20	79.00	75.75
Gross Output Factor, %	89.20	89.65	90.32	89.70	86.89	87.43	88.10	87.76	86.53	86.79	83.12	83.37	87.53

HMP'L 1 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	YTD
EFOR, %	7.77	0.00	1.01	0.33	1.64	0.00	0.00	1.93	6.96	0.25	0.77	0.27	1.77
EFOR KPI Target, %	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
EAF, %	90.88	98.75	97.85	98.83	96.52	99.43	90.54	98.07	93.04	98.44	98.91	99.73	96.73
EAF KPI Target, %	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80	92.80
Forced Outage Hours	55.20	0.00	0.00	0.00	11.80	0.00	0.00	0.00	19.50	1.30	0.00	0.00	87.80
Unplanned(4) Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	53.70	0.00	0.00	9.50	0.00	0.00	63.20
Planned Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Planned Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unplanned(4) Derating MWH	1654.5	1385.0	1400.0	996.0	2249.0	672.0	2753.9	0.0	0.0	40.0	378.0	0.0	11,528.4
Forced Derating MWH	430.5	0.0	1240.0	393.0	70.0	0.0	0.0	2370.0	5047.5	92.5	915.0	330.0	10,888.5
Equivalent Derated Hours	12.64	8.39	16.00	8.42	14.05	4.07	16.69	14.36	30.59	0.80	7.84	2.00	135.86
Equiv. Forced Derated Hours	2.61	0.00	7.52	2.38	0.42	0.00	0.00	14.36	30.59	0.56	5.55	2.00	65.99
Forced Outage Rate, %	7.42	0.00	0.00	0.00	1.59	0.00	0.00	0.00	2.71	0.18	0.00	0.00	1.01
Availability Factor, %	92.58	100.00	100.00	100.00	98.41	100.00	92.78	100.00	97.29	98.55	100.00	100.00	98.28
Gross Capacity Factor, %	87.67	96.74	94.86	96.23	90.78	95.95	86.23	91.01	87.12	94.46	94.74	93.70	92.41
Gross Output Factor, %	94.69	96.74	94.86	96.23	92.24	95.95	92.94	91.01	89.54	95.85	94.74	93.70	94.03

HMP'L 2 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	YTD
EFOR, %	6.83	7.10	8.47	0.05	9.93	0.95	7.02	1.39	2.13	11.61	7.12	0.00	5.55
EFOR KPI Target, %	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
EAF, %	90.56	90.10	91.31	28.49	77.10	97.35	89.48	95.67	87.69	88.39	92.88	100.00	85.82
EAF KPI Target, %	91.70	91.70	50.30	70.30	91.70	91.70	91.70	91.70	91.70	91.70	911.70	91.70	86.50
Forced Outage Hours	49.20	39.80	44.30	0.00	67.00	6.40	45.10	0.00	0.00	84.10	46.90	0.00	382.80
Unplanned(4) Outage Hours	0.00	0.00	0.00	0.00	49.50	0.00	0.00	0.00	59.30	0.00	0.00	0.00	108.80
Planned Outage Hours	0.00	0.00	0.00	501.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	501.80
Planned Derating MWH	0.0	0.0	0.0	1566.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,566.5
Unplanned(4) Derating MWH	3345.6	3239.1	280.0	542.2	8925.7	2100.0	4473.0	3768.1	2620.0	0.0	0.0	0.0	29,293.7
Forced Derating MWH	277.5	1357.0	3221.2	19.0	340.0	75.0	1227.5	1777.5	2425.7	415.0	748.0	0.0	11,883.4
Equivalent Derated Hours	21.06	26.72	20.36	12.37	53.87	12.65	33.14	32.24	29.34	2.41	4.35	0.00	248.51
Equiv. Forced Derated Hours	1.61	7.89	18.73	0.11	1.98	0.44	7.14	10.33	14.10	2.41	4.35	0.00	69.09
Forced Outage Rate, %	6.61	5.92	5.95	0.00	9.65	0.89	6.06	0.00	0.00	11.29	6.51	0.00	4.70
Availability Factor, %	93.39	94.08	94.05	30.21	84.34	99.11	93.94	100.00	91.76	88.71	93.49	100.00	88.66
Gross Capacity Factor, %	86.12	84.78	88.20	26.99	72.30	92.82	85.36	88.99	81.97	82.68	85.38	89.59	80.50
Gross Output Factor, %	92.22	90.12	93.78	89.34	85.72	93.66	90.87	88.99	89.33	93.20	91.33	89.59	90.79

HMP'L 1 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	YTD
EFOR, %	4.50	2.04	0.00	0.00	0.00	2.12	0.00	12.22	0.05	2.78	#DIV/0!	0.34	2.29
EFOR KPI Target, %	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
EAF, %	95.29	96.70	91.68	99.88	91.97	97.21	93.35	87.78	99.82	22.04	0.00	53.88	77.33
EAF KPI Target, %	89.60	89.60	37.60	80.60	89.60	89.60	89.60	89.60	89.60	89.60	89.60	89.60	84.50
Forced Outage Hours	6.90	13.20	0.00	0.00	0.00	0.00	0.00	90.00	0.00	4.10	0.00	0.70	114.90
Unplanned(4) Outage Hours	0.00	0.00	53.40	0.00	50.80	0.00	45.50	0.00	0.00	0.00	0.00	0.00	149.70
Planned Outage Hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	576.10	720.00	338.60	1634.70
Planned Derating MWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	522.5	522.5
Unplanned(4) Derating MWH	262.5	1400.0	1397.5	140.4	1480.5	791.5	658.0	0.0	152.0	0.0	0.0	0.0	6,282.4
Forced Derating MWH	4381.0	85.0	0.0	0.0	0.0	2522.5	0.0	152.5	62.5	97.5	0.0	115.0	7,416.0
Equivalent Derated Hours	28.14	9.00	8.47	0.85	8.97	20.08	3.99	0.92	1.30	0.59	0.00	3.86	86.19
Equiv. Forced Derated Hours	26.55	0.52	0.00	0.00	0.00	15.29	0.00	0.92	0.38	0.59	0.00	0.70	44.95
Forced Outage Rate, %	0.93	1.96	0.00	0.00	0.00	0.00	0.00	12.10	0.00	2.43	#DIV/0!	0.17	1.65
Availability Factor, %	99.07	98.04	92.82	100.00	93.17	100.00	93.88	87.90	100.00	22.12	0.00	54.40	78.32
Gross Capacity Factor, %	88.56	90.25	87.07	96.01	86.85	91.84	89.63	84.57	96.19	21.23	0.00	52.42	73.60
Gross Output Factor, %	89.39	92.06	93.80	96.01	93.22	91.84	95.47	96.21	96.19	95.99	#DIV/0!	96.36	93.98

HMP'L 2 MONTHLY REPORT

AVAILABILITY REPORT

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	YTD
EFOR, %	5.89	0.00	11.54	0.00	0.00	0.00	0.00	0.17	0.52	0.00	0.81	0.00	**1.67**
EFOR KPI Target, %	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	**10.00**
EAF, %	86.98	85.60	77.88	93.09	71.26	90.37	90.19	91.50	85.31	91.89	95.88	89.08	**87.39**
EAF KPI Target, %	87.40	87.40	56.40	78.70	87.40	87.40	87.40	87.40	87.40	87.40	87.40	87.40	**84.10**
Forced Outage Hours	24.90	0.00	83.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**108.60**
Unplanned(4) Outage Hours	0.00	52.00	0.00	0.00	0.00	0.00	0.00	0.00	53.50	0.00	0.00	51.60	**157.10**
Planned Outage Hours	0.00	0.00	0.00	0.00	181.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**181.50**
Planned Derating MWH	0.0	0.0	0.0	0.0	455.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**455.0**
Unplanned(4) Derating MWH	9121.2	7697.6	13540.7	8546.0	5101.8	11920.0	12552.0	10655.4	8384.0	10392.0	4098.0	5098.4	**107,107.1**
Forced Derating MWH	3255.0	0.0	370.0	0.0	0.0	0.0	0.0	217.5	600.0	0.0	1008.0	0.0	**5,450.5**
Equivalent Derated Hours	71.95	44.75	80.88	49.69	32.31	69.30	72.98	63.21	52.23	60.42	29.69	29.64	**657.05**
Equiv. Forced Derated Hours	18.92	0.00	2.15	0.00	0.00	0.00	0.00	1.26	3.49	0.00	5.86	0.00	**31.69**
Forced Outage Rate, %	3.35	0.00	11.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**1.29**
Availability Factor, %	96.65	92.26	88.75	100.00	75.60	100.00	100.00	100.00	92.57	100.00	100.00	93.06	**94.89**
Gross Capacity Factor, %	81.01	80.12	72.19	86.70	66.34	85.52	85.20	86.20	81.77	87.97	91.53	83.99	**82.35**
Gross Output Factor, %	83.81	86.83	81.34	86.70	87.74	85.52	85.20	86.20	88.34	87.97	91.53	90.25	**86.78**

ATTACHMENT 7

COMPARISON OF EXHIBIT C TO THE BREC PRODUCTION WORK PLAN

	Item #	Description	Exhibit C Amount ($)	Amount in BREC Production Work Plan ($)	Difference	Comment
Section A						
	I.	2008 Capital Budget	$ 4,095,684	$ 4,095,684	$ -	
	II	2009 Capital Budget	$ 5,653,192	$ 6,747,809	$ 1,094,617	
	III	2010 Capital Budget	$ 3,783,080	$ 3,829,333	$ 46,253	
	IV	2008 O&M Non-Labor Budget	$ 10,573,064	$ 10,573,064	$ -	
	V	2009 O&M Non-Labor Budget	$ 10,944,055	$ 11,626,950	$ 682,895	
	VI	2010 O&M Non-Labor Budget	$ 11,768,042	$ 12,235,146	$ 467,104	
					$ -	
					$ -	
Section B						
	VII	H-1 Precipitator Repairs	$ 3,224,074	$ 280,000	$ (2,944,074)	Precip. Hoppers 9-12 are budgeted to be replaced in 2009 at 250k and new controls in 2011 at 30k
	VIII	H-2 Precipitator Repairs	$ 3,224,074	$ 230,000	$ (2,994,074)	Precip. Hoppers 9-12 are budgeted to be replaced in 2010 at 200k and new controls in 2012 at 30k
	IX	H-1 Repair Dry Side Ductwork	$ 297,222	$ -	$ (297,222)	H-1 had major duct work repairs completed in 2005
	X	H-2 Repair Dry Side Ductwork	$ 297,222	$ 300,000	$ 2,778	The precipitator outlet duct to the pass-bass stack breeching is budgeted to be replaced during the Spring 2010 outage at 300k.
	XI	H-1 Structural & Life Assessments	$ 1,192,362	$ 265,225	$ (927,137)	Structural and Life Assessments are budgeted to be performed during the 2009 Spring outage.
	XII	H-2 Structural & Life Assessments	$ 1,192,362	$ 273,182	$ (919,180)	Structural and Life Assessments are budgeted to be performed during the 2010 Spring outage.
	XIII	H-1 Booster Fan	$ 104,901	$ 50,000	$ (54,901)	The booster fan blade erosion covers are scheduled to be replaced during the Spring 2009 outage.
	XIV	H-2 Booster Fan	$ 104,901	$ 50,000	$ (54,901)	The booster fan blade erosion covers are scheduled to be replaced during the Spring 2010 outage.
	XV	H-1 Clean Coal Dust and Fly Ash	$ 346,045	$ 53,045	$ (293,000)	Major cleaning was completed in 2008 and additional cleaning is scheduled in 2009.
	XVI	H-2 Clean Coal Dust and Fly Ash	$ 346,045	$ 53,045	$ (293,000)	Major cleaning was completed in 2008 and additional cleaning is scheduled in 2009.
	XVII	H-1 Boiler Structural Painting	$ 3,000,000	$ -	$ (3,000,000)	Exhibit C has $3M per unit and the Exothermic report on the enclosed CD has $1.75M per unit
	XVIII	H-2 Boiler Structural Painting	$ 3,000,000	$ -	$ (3,000,000)	Exhibit C has $3M per unit and the Exothermic report on the enclosed CD has $1.75M per unit
	XIX	H-1 SCI Baseline Repairs	$ 1,192,362	$ -	$ (1,192,362)	The SCI baseline report is outdated and most major items have been addressed.
	XX	H-2 SCI Baseline Repairs	$ 1,192,362	$ -	$ (1,192,362)	The SCI baseline report is outdated and most major items have been addressed.
					$ -	

	Item #	Description	Exhibit C Amount ($)	Amount in BREC Production Work Plan ($)	Difference	Comment
					$ -	
Section C						
	XXI	H-1 and H-2 Exothermic Eng Repair List	$ 17,134,000	$ 5,729,840	$ (11,404,160)	The difference of $11.4M is made up by two items. 1) $3.5M for boiler painting. This is a double dip because $6M is also included in Section B for boiler structural painting. 2) The remaining $7.9M is cost estimates from the Exothermic Engineering report to repair the remaining 1371 items in the photographs. **Note: These numbers represent Exothermic estimates which we have found to be about 80% higher than needed. WKE has repaired 738 of the 2109 items in the Exothermic report at a cost of less than $600,000. The estimated cost in the Exothermic report to repair these same items is $3,163,840.**
	XXII	H-1 Exothermic Engineering Dry Fire Assessment Repair	$ 3,484,344	$ -	$ (3,484,344)	No repairs are necessary. Metallurgical reports from both the WKE vendor and the Exothermic vendor confirms there were no issues found in the visual and dimensional inspection of the tube samples. There were no concerns with the microstructure, and no lose of expected life for the waterwalls and the radiant superheater.
					$ -	
Section D					$ -	
	XXIII	Dredging Station Two Ash Pond	$ 5,424,000	$ 5,508,362	$ 84,362	Included in the BREC Production Work Plan in 2015
					$ -	
Totals			**$ 91,573,393**	**$ 61,900,685**	**$ (29,672,708)**	The difference ($29.6M) is the amount of the $92M not funded in the BREC Production Work plan. About 20% of this number is a more realistic estimate as we have found it only takes about 20% of the Exothermic estimate to actually make the repairs.

Notes:
Section "B" is items contained in the BREC initial draft work plan. After obtaining additional information, it was determined that several projects were overstated in the draft plan.

ATTACHMENT 8

EMAIL FROM WAYNE THOMPSON TO WKE PERSONNEL

Crosby, W. Duncan

From: Wayne Thompson [WThompson@hmpl.net]
Sent: Monday, April 09, 2007 5:35 PM
To: Berry, Bob
Cc: Ken Brooks; Baronowsky, Larry
Subject: 2007/2008 Station Two Budget

Bob

I would like to thank you and your staff for your time on April 5th to discuss the draft 2007/2008 budget year Station Two Budget. This meeting was a good start but we have a long ways to go in this area.

As was discussed in that meeting it will be hard for HMP&L to support a $13,000,000 increase over last year's budget of $23,000,000 for a total budget of over $36,000,000 in this budget year.

I understand what the major cost drivers are (outages, capital expenditures)and that we have agreed to fund some major capital improvements at Station Two such as controls replacement, and the dry fly ash system. We will continue to support those projects that we have started but we can not all of the capital improvements in the draft budget.

We need to reduce this budget a lot more than what was agreed to so for. I would like to request that your staff go back over the budget and look at any item that may be moved out of this budget. I would like for you or your staff to look at the possible of the Spring 2008 H2 Planned Outage being moved to the Fall of 2008 to help with this year budget I understand that this is a lot of work and that WKE will have to look at this request from what impact it may have on the WKE system as a whole.

I appreciate your help in this matter.

Wayne