    until the permanent burner solution is installed. **Bechtel anticipates restarting the unit mid-August with a new substantial completion date of 10/12/10.** This impact to commissioning was communicated through a formal letter to KYPSC.

  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Written agreement expected within next two weeks.
  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
  - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Schedule/Execution –NTR
  - Permitting – NTR
  - Engineering/General:
    - Reviewing Voith updated scope for rehabilitation minus automation.
    - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
  - Budget:
    - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
    - Revised project sanction planned for August IC meeting
  - Contracting:
    - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR

- Engineering/General
    - Bids have been received and the two lowest bidders were invited in for discussions the week of August 1, 2010. Project Engineering is reviewing the bids and anticipated an award by August 31, 2010.
    - Working with URS to develop RFQ for long lead equipment. (This process was delayed as options for Mill Creek Air Compliance strategies were explored. Activities associated with ordering the limestone equipment will resume the week of August 16, 2010.)
- Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
- Contracting – NTR
- Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
    - Permitting
        - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
    - Engineering
        - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
        - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
        - Transmission working towards relocation of the 69kV line.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
    - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
    - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
    - Schedule/Execution:
        - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
        - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
        - Work has begun on both Emergency Spillways.
        - Working continues on the fiberglass piping for the project

  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk
    - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
    - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
  - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
  - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCP transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Detailed Engineering for the Landfill is focusing on completion of construction drawings.
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  - Contract Disputes/Resolution – NTR

  - Issues/Risk:
    - Land Acquisition – a final offer that will discuss condemnation potential will be sent to the remaining three land owners in early July. A final recommendation will be presented to management for approval on whether to change designs or condemn the remaining property in late July.

- **General CCP Projects**
  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension. Summit demobilized 90% of equipment and performed requested gradework and site stabilization activity.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Continued rock embankment blasting at the Houp Property.
      - Began rock embankment placement on the East side foundation.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Proposals for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI received July 20.
    - Bid review meetings held with stations and all suppliers July 26 & 28.
    - Initial team evaluation sheets due COB Friday July 30. Summary discussion meeting to be set the week of Aug. 2.
    - Bid Summary – dry system pricing ranges from $2.2 to $6.3M per system with numerous clarifications and further engineering to be performed and evaluated. **Meaningful pricing not submitted for the wet system.**

            - URS – only offered core technology equipment, no BOP, no construction. 2 ppmv guarantee at the stack with LD to 10% of equipment cost
            - Nol-Tec – turn-key offer, similar to our existing systems with substantial upgrades. 2 ppmv guarantee with LD to contract price
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    - Budget – Spending $3M in 2010 is dependent on the procurement process and discussions surrounding delaying MC work.
    - Testing – Contracts need to be placed and test plans need to be prepared on the following:
        - Notify Air Quality Services that they will be doing testing from 8/16-8/27 at Brown.
        - Notify Clean Air Engineering that they will be doing testing from 8/16-8/27 at Ghent.
        - Notify EON Engineering that they will be doing testing from 8/22-9/3 at Ghent.

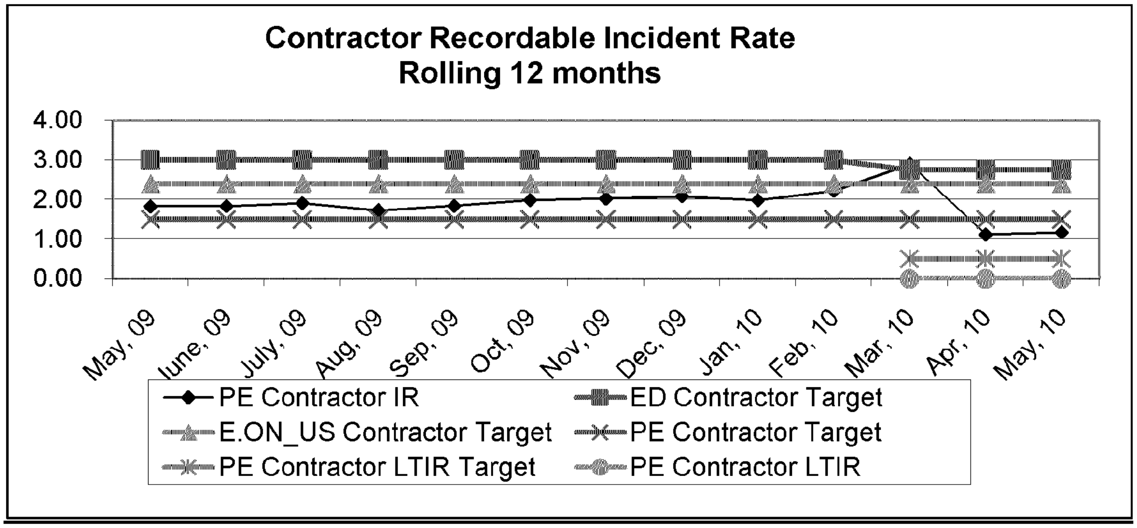
- **SO3 Mitigation (Ghent)**
    - Preparing for MgO injection at GH4.
    - Stoic Calculations for Ghent testing prepared.
    - B&V reworking SAM calculations for the Ghent Units based on Title V Heat Inputs..
    - B&V draft BACT analysis submitted and commented by E.ON.
    - B&V requested to prepare two more documents:
        - BACT based on 2005 RBLC database for emissions limits
        - Technology choice based on a 5 ppmv requirement

- **NBU1 and Other Generation Development**
    - LFG
        - Landfill Gas Sample Result completed – final sample report outstanding.
        - LFG Technologies completed landfill visits.
        - Draft report expected week of August 2.
    - NBU CR – Complete draft of documents submitted July 20. E.ON comments submitted July 28. Final draft expected week of August 2.
    - Biomass –
        - Complete draft report from B&V due the week of August 2.

        - Moore Ventures completed a fuel analysis assessment.
    - CCS 100 MW Project – Prepared a SOW and RFP for study work regarding a DOE/State/E.ON project. Submitted comment to presentation to DOE. Project will not get funding for a 2016 100 MW project – as such internal work ceased prior to releasing RFP to Bechtel, Fluor, Battelle, and EPRI.
    - FutureGen – NTR

- **General**
    - Impoundment Integrity Program – PE is transitioning this to Generation Services.
    - Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost. Plans are underway to extend the B&V contract to begin discussing various scenarios for compliance with upcoming environmental air regulations.
    - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A revised recommendation will be presented to officers within ES the week of 8/6/10.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Philip Imber has submitted for two postings outside of ES.
3. Jason Finn has submitted for positions.
4. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From:	Lively, Noel
To:	Straight, Scott
Sent:	8/16/2010 6:25:56 AM
Subject:	PE's Bi-Weekly Update of 7-30-10.docx
Attachments:	PE's Bi-Weekly Update of 7-30-10.docx

Energy Services - Bi-Weekly Update
August 16, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Chimney Coatings – Testing of the coating application remain.
      - SCR/FGD Icing Siding – Installation nearing completion.
      - Unit 4 ID Fans – An outage kickoff meeting is planned for 8/4/10.
      - Chimney Capping – Caps placed by helicopter on both chimneys on 7/25/10.
      - Elevators - Award Recommendation is circulating for signatures.
    - Brown
      - The FGD continues to operate very well.
      - E.W. Brown Gypsum Dewatering Facility
        - Product to be sent to the facility next week for final commissioning activity. This was delayed a week due to high ash content in gypsum stream.
        - Facility operation award recommendation being routed for signatures.
      - E.W. Brown Coal Pile Modification
        - Bid received for engineering from MACTEC and PO under development.
      - Balance of Project Items
        - Paving scope out for bid
        - Elevator scope out for bid
  - Budget – Slight reduction in the total Brown FGD Program ITC to $408.8m.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks - NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – Bechtel has completed installation of the new burner parts. Meetings were held Aug 11-12 to discuss operational issues and needed changes. **The unit is on schedule to restart Aug 16 for a completion date of Oct 12.** This impact to commissioning was communicated through a formal letter to KYPSC.
  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Written agreement expected within next two weeks.

  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
  - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Schedule/Execution –NTR
  - Permitting – NTR
  - Engineering/General:
    - Reviewing Voith updated scope for rehabilitation minus automation.
    - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
  - Budget:
    - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
    - Revised project sanction planned for August IC meeting
  - Contracting:
    - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR
  - Engineering/General
    - Pre-bid meeting for the building extension work was held at Mill Creek on July 8, 2010 and bids were received July 23, 2010.
    - Working with URS to develop RFQ for long lead equipment.
  - Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
  - Contracting – NTR

  - Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
    - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
    - Work has begun on both Emergency Spillways.
    - Working continues on the fiberglass piping for the project
  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk

        - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
        - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
    - Schedule/Execution - NTR
    - Budgeting - NTR
    - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
    - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
    - Schedule/Execution – NTR
    - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
    - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCP transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Detailed Engineering for the Landfill is focusing on completion of construction drawings.
    - Permitting – All permit applications have been made. Project Engineering is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with planning with the local authorities and the cemetery where the remains will be relocated.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk:
        - Land Acquisition – a final offer that will discuss condemnation potential will be sent to the remaining three land owners in early July. A final recommendation will be presented to management for approval on whether to change designs or condemn the remaining property in late July.

- **General CCP Projects**
    - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
  - Safety – NTR
  - Schedule/Execution:
    - Work on Phase I is being suspended until a decision is made on whether to convert the main pond to a landfill.
    - Working on evaluation and recommendation paper for the main pond conversion from a pond to a landfill .
    - Aux Pond Phase II work awarded to Charah.
  - Budget – NTR
  - Contract Disputes/Resolution - NTR
  - Issues/Risk – A decision is required in July on whether to continue with the Main Pond or convert to a dry landfill. Economics indicate conversion now to be least cost compared to continuing with pond and then converting once regulations are final.

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension except for rock embankment placement, dust control, and general site maintenance.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
      - Rock placement continued on the West and South Embankments.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Installation of erosion and sediment control measures.
      - Topsoil stockpiles were relocated.
      - Began rock embankment blasting at the Houp Property.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

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  - Safety – NTR
  - Schedule/Execution:
    - Proposals for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI received July 20.
    - Bid review meetings held with stations and all suppliers July 26 & 28.
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    - Landfill Gas Sample Result completed – final sample report outstanding.
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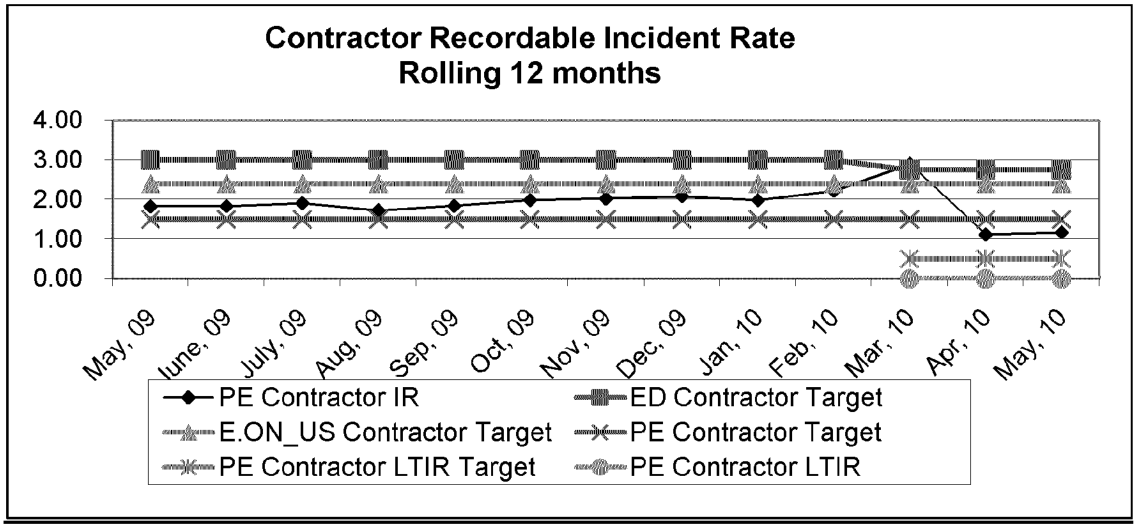

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From:	Hillman, Timothy M.
To:	Straight, Scott
CC:	Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Sent:	8/19/2010 2:46:19 PM
Subject:	15.0200 100819 Mill Creek AQC Workshop of Aug 5-6 - Final Meeting Minutes
Attachments:	Mill Creek AQC Workshop Aug 5-6 - Conf Memo Final 081910.pdf

Scott,

As we discussed in our Tuesday (8/17) conference call, please find attached final meeting minutes from our Mill Creek AQC Workshop of August 5th and 6th.

Best Regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Hillman, Timothy M.
Sent: Monday, August 16, 2010 8:18 AM
To: 'Straight, Scott'
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Scott,

Please find attached a revised table indicating 96 percent removal for the refurbished scrubbers. We also made a slight revision to the AQC schematic and cost table, adding a key to the legend indicating that Unit 1's ESP would be removed.

We look forward talking to you tomorrow during our conference call.

Best regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Straight, Scott [mailto:Scott.Straight@eon-us.com]
Sent: Thursday, August 12, 2010 1:34 PM
To: Hillman, Timothy M.; Saunders, Eileen
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Tim,

The targeted SO2 removal for the Unit 1, Unit 2 and Unit 4 (to serve Unit 3) FGDs is 96%, not 93%. They are doing this now at times.

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040
scott.straight@eon-us.com

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
igust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 19, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION

Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
    - Are they overly conservative?
    - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
    - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.

35. Plant access road and rail tracks are impacted with AQC additions.

36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.

37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.

38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.

39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.

40. Reagent costs are the down side to any DFGD addition to the units.

41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.

42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.

43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.

44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.

45. All pumps are routinely redesign/replaced.

46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.

    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.

47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:

    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.
49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.
50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.
51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.
    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised up from Gary R- during mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

		2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
Plant	Unit	SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	I NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			Average =	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.001	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.009	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			0	0	0	0.007	0.000	0.000		
							5,056	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994**	**-4,787**	**1,585**					
							Phase I	Phase						
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	**-**	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	> 0.5	> 0.5
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

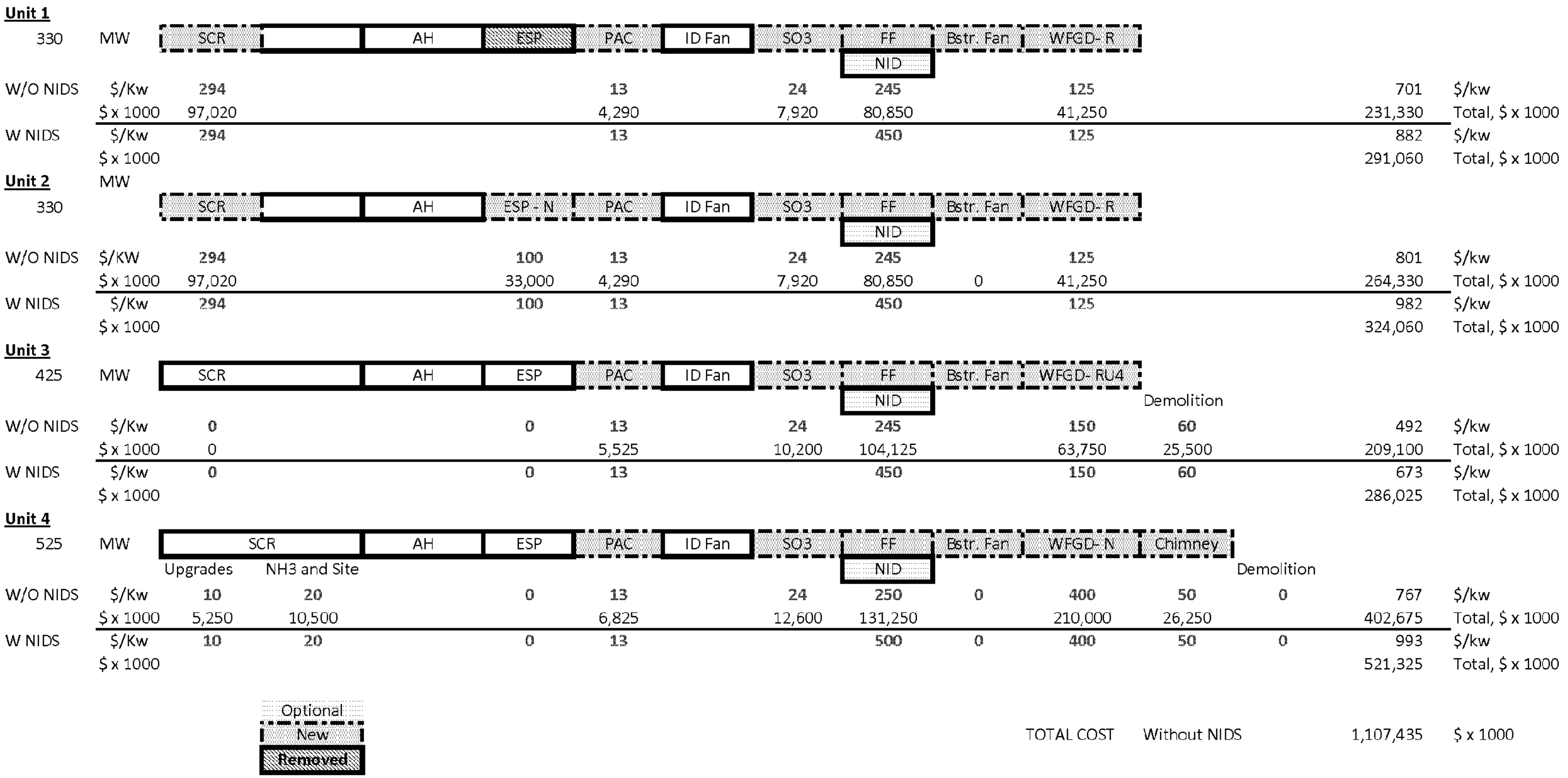
Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

	MW	Unit	Current Emissions lb/mmBtu	Current Removal %	Future Removal %	Planned future		Preliminary Schedule					
						TECH	**Priority**	**FGD**	**FF**	**SCR**	**Fans**	**Chimney**	**FF Location**
	330	1	0.48	92	96	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	96	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	96	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

Rev 1, 100813

Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results



Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional
New
Removed

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include
- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

Rev 1, 100813

From:	Hillman, Timothy M.
To:	Straight, Scott
CC:	Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Sent:	8/16/2010 9:17:35 AM
Subject:	RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Attachments:	EON cost Analysis Mill Creek Upgrade Final Rev 1.pdf

Scott,

Please find attached a revised table indicating 96 percent removal for the refurbished scrubbers. We also made a slight revision to the AQC schematic and cost table, adding a key to the legend indicating that Unit 1's ESP would be removed.

We look forward talking to you tomorrow during our conference call.

Best regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Straight, Scott [mailto:Scott.Straight@eon-us.com]
Sent: Thursday, August 12, 2010 1:34 PM
To: Hillman, Timothy M.; Saunders, Eileen
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Tim,

The targeted SO2 removal for the Unit 1, Unit 2 and Unit 4 (to serve Unit 3) FGDs is 96%, not 93%. They are doing this now at times.

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040
scott.straight@eon-us.com

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
gust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

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Rev 1, 100813

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- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

Rev 1, 100813

From: Straight, Scott
To: Straight, Scott; Thompson, Paul; Voyles, John; Bowling, Ralph; Sturgeon, Allyson; Hudson, Rusty; Hincker, Loren; Sinclair, David; Schetzel, Doug; Yussman, Eric; Jackson, Fred
CC: Waterman, Bob; Imber, Philip; Lively, Noel; Saunders, Eileen; Gregory, Ronald; Heun, Jeff; Hance, Chuck; Clements, Joe; Cooper, David (Legal); Jones, Greg; Keeling, Chip; Hendricks, Claudia; Ray, Barry; O'brien, Dorothy (Dot); Bellar, Lonnie; Blake, Kent
Sent: 8/16/2010 9:49:23 AM
Subject: RE: Project Engineering's ES Bi-Weekly Report - August 16, 2010
Attachments: PE's Bi-Weekly Update of 8-16-10.docx

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040
scott.straight@eon-us.com

Energy Services - Bi-Weekly Update
August 16, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Unit 4 ID Fans – On plan for fall outage.
      - Elevators - Abell Elevator Company has received the contract for their signature.
    - Brown
      - Fluor continues to work on punch-list items and demobilization activities.
      - On plan for Unit 1 outage tie-in.
      - Gypsum slurry sent to de-watering facility on 8/5.
      - Gypsum de-watering operational contract awarded to FPG.
      - MACTEC awarded engineering contract for coal yard extension. Soil borings and engineering have begun.
      - Paving scope bids received.
      - Elevator scope bids received.
  - Budget – NTR.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks – NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – Bechtel has completed installation of the new burner parts. Meetings were held Aug 11-12 with Bechtel and DBEL to discuss operational issues and needed changes for restart. **The unit is behind schedule for the planned restart on Aug 16 due to air balancing issues and erroneous thermocouple readings.**
  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Comments sent to Bechtel on change order draft with expectations of reaching agreement on language of FM and EE claims the week of 8/16.
  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
    - Schedule/Execution – NTR
    - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
    - Engineering – proceeding as planned to support the spring 2012 in-service.
    - Budget - NTR
    - Contracting – NTR
    - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
    - Schedule/Execution –NTR
    - Permitting – NTR
    - Engineering/General:
        - Engineering of Voith scope, automation, historic preservation and de-watering in progress.
    - Budget:
        - NTR
        - Revised project sanction planned for August IC meeting
    - Contracting:
        - Negotiations held with Voith on 8/12-8/13 went very well. PE is still pushing negotiations to support IC review/approval in August, albeit very tight. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
    - Issues/Risk
        - Release of third unit runner to Voith is required in August to maintain schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
    - Safety - NTR
    - Auditing - NTR
    - Permitting - NTR
    - Engineering/General
        - Bids have been received for the maintenance building. PE is reviewing the bids and anticipates an award by 8/31.
        - Working with URS to develop RFQ for long lead equipment. (This process was delayed as options for Mill Creek Air Compliance were explored. Activities associated with ordering the limestone equipment will resume the week of 8/16)
    - Budget
        - AIP complete.
        - Revised cash flow reflected in 2011 MTP
    - Contracting – NTR
    - Issue/Risk – NTR

- **Cane Run CCP Project**
    - Permitting
        - 404/401 and Landfill Permit applications remain under review by the agencies. To date permitting process has gone well.
    - Engineering
        - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
        - Transmission working towards relocation of the 69kV line.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
    - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
    - Working with UCC to update their equipment and material pricing.
    - 2010 budget reduced to $1m for this scope with the remainder moving to 2011.

- **TC CCP Project – BAP/GSP**
    - Schedule/Execution:
        - GSP's Flexible Membrane Liner (FML) and Geo-synthetic Clay Liner (GCL) scheduled to begin in September.
        - Work continues on fill placement and mechanically stabilized earth wall with the north and west dikes substantially completed.
        - Work has begun on both Emergency Spillways.
        - The fiberglass piping for the project has been substantially completed.
    - Budgeting – The $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations may require IC approval. PE is tracking the overall cost of the project against the remaining contingency before seeking increased authorization and revised AIP.
    - Engineering:
        - The study on the GSP clay liner originally installed to compare against potential new regulations has been completed. Path forward is to utilize the existing clay liner as part of a composite liner system.
        - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
    - Permitting – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk
        - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010. The contractor has also submitted financial claims for delays. The claim is being reviewed by PE.
        - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs are being reviewed.
  - Permitting – Both the June and July Anabat studies have been completed for the Indiana Bat. A third party has reviewed the June data and confirmed no findings of the Indiana Bat. The July data is being prepared to be sent to the third party.
  - Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – PE is working with Zachry Engineering to perform a sanity high-level scope and estimate check against the B&V scope and estimate on CCR Transport system. This review is planned to wrap up by the end of August.
  - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCR transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Drawings and Sepcifications for the Detailed Engineering for the Landfill have been submitted for review by EON-US.
  - Permitting – All permit applications have been made. PE is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with the final step in the relocation process being approved by the Carroll County Fiscal Court on 8/10. The relocation will occur in September or October.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk:
    - Land Acquisition – a final offer that discusses condemnation potential was sent to the McDole and Owens land owners. A second letter will be sent to the third remaining land owner the week of 8/16.

- **General CCP Projects**
  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These costs have been included in PE's 2011 MTP draft.
  - PE is working with Legal and US EPA in regards to defense of the KPDES Permit

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – NTR
    - Schedule/Execution:
      - Contract work remains under suspension. Summit demobilized 90% of equipment and performed requested grade work and site stabilization activity.

        - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning 7/6 until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
        - Continued rock embankment blasting at the Houp Property.
        - Began rock embankment placement on the East side foundation.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Held teleconferences with Nol-Tek and BCSI – both to provide initial draft of a conformed, redline version of the technical specification and GSA.
    - URS site visit to Ghent held on 8/12. URS to provide commercial response (GSA mark up and guarantee language) the week of 8/16. URS to provide a Ghent 2 technical proposal 9/10. Imber and Straight to visit URS in Austin on 8/23.
    - Sent letters of dismissal to the other three bidders.
        - FLS/CoaLogic – lack of competitive SO3 removal guarantee and the lack of a competitive commercial position regarding the SO3 removal
        - Clyde Bergemann - lack of a competitive the SO3 removal guarantee and no technical advancement
        - UCC – least robust system proposed, lack of confidence in the technical proposal as evaluated by the technical team
    - Path forward to October investment committee is convoluted due to URS submittal and the new options being considered at Mill Creek as a result of the fleet wide environmental studies.
  - Budget – Spending $3M in 2010 is dependent on the procurement process and discussions surrounding delaying MC work.
  - Testing – Contracts prepared but not finalized. Brown and Ghent testing plans published for Aug. 16 – Sep 3:
    - Air Quality Services will be doing testing from 8/16-8/27 at Brown.
    - Clean Air Engineering will be doing testing from 8/16-8/27 at Ghent.
    - EON Engineering will be doing testing from 8/22-9/3 at Ghent.

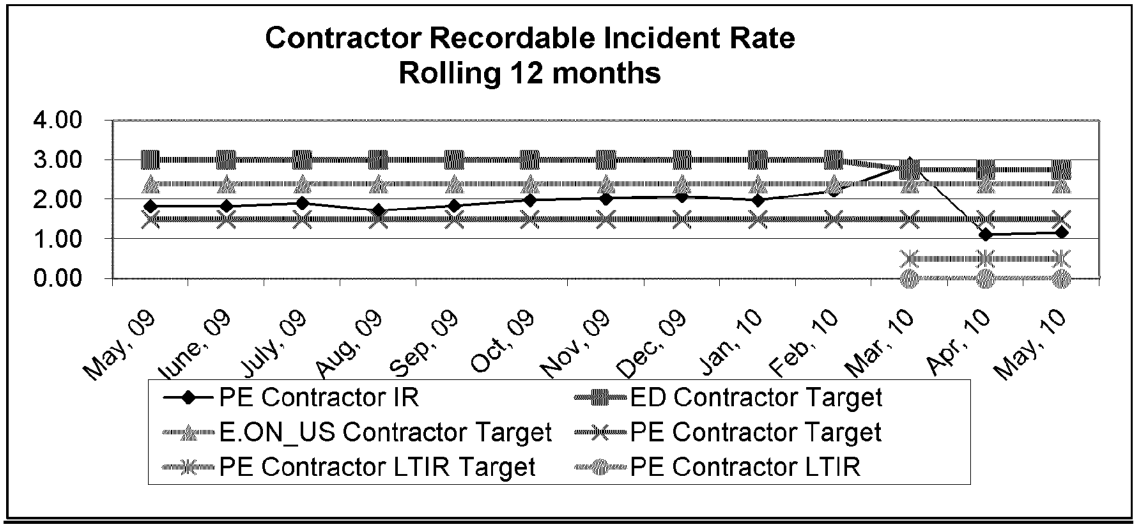
- **SO3 Mitigation (Ghent)**
  - AIPs being processed for each unit for $250k to allow charging of testing/engineering.
  - Preparing for MgO injection at GH4 with Breen. Breen has been at Ghent in preparation of the testing.

  - Calculations for Ghent SAM life cycle reviewed with B&V. Four sets of calculations are being prepared:
    - Base calculation for BACT analysis with all layers of catalyst in place
    - Calculation based on exact operation today.
    - Calculation based on pre-FGD operation with 1.2 lb SO2/mmbtu fuel
    - Calculation pre-SCR operation with 1.2 lb SO2/mmbtu fuel
  - B&V re-draft of BACT analysis and Life Cycle analysis expected week of 8/16
  - B&V requested to prepare two more documents:
    - BACT based on 2005 RBLC database for emissions limits
    - Technology choice based on a 5 ppmv requirement

- **NBU1 and Other Generation Development**
  - LFG - LFG Technologies provided a draft report and updates based on E.ON comment.
  - NBU Cane Run
    - New pro-forma submitted.
    - Outstanding items to be completed: property line drawing and schedule updates
  - Biomass
    - Draft report received with E.ON comments being prepared to release to B&V the week of 8/16.
  - CCS 100 MW Project – Director of Business Development still working on contract with the state. PE in discussion with Battelle, Fluor, Bechtel and EPRI for support of this study work.
  - FutureGen – New project announced in Indiana as a Oxyfuel plant. Path forward for technical committee not identified at this time.

- **General**
  - Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost. Plans are underway to extend the B&V contract to begin discussing various scenarios for compliance with upcoming environmental air regulations. Over $1B removed from Mill Creek Air Compliance after meeting with Kirkland, PE and B&V senior level engineers.
  - Revised Air Compliance cash flows communicated within ES on 8/13. The three scenarios are for a 2014, 2015 and 2016 CATR with all three scenarios having a 1-year delay on HAPs to 2017.
  - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A revised recommendation will be presented to officers within ES the week of 8/6/10.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Jason Finn has submitted for positions.
3. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From: JOE.CLEMENTS@EON-US.COM
To: Saunders, Eileen
Sent: 9/8/2010 9:54:51 AM
Subject: AIP Project Approval - 131693 - ORIGINAL
Attachments: 2011 MTP Level I Engineering - Air Compliance Projects.docx; 131693-6.pdf

LG&E project number 131693 (Envir Compliance Study-Air-LGE) has been submitted for your approval. Please login to PowerPlant and respond to the items awaiting your approval.

login to powerplant

Investment/Contract Proposal for IC: e-mail vote on 8/27/10

Project Name:	MTP Engineering – Air Compliance Projects
Total Expenditures:	$2,000K
Sole Source Amount:	$1,600K
Project Number:	131693 – LG&E 131694 - KU
Business Unit/Line of Business:	LG&E and KU Coal-Fired Generation
Prepared/Presented By:	Eileen Saunders/Scott Straight

Executive Summary

This request seeks authorization of $2,000K to continue refining the scopes, implementation schedules and cost estimates of projects identified in the development of the 2011 MTP as necessary for compliance with proposed or final local, State and Federal air compliance regulations through 2016.

In addition to requesting approval of a new engineering project that will continue refining the 2011 MTP air compliance scope, this request also seeks approval of a sole source award to Black &Veatch (B&V) engineering firm. B&V will perform the majority of studies included in the $2 million project sanction request; however, smaller valued contracts will be awarded to various technology firms to perform miscellaneous reviews of the LG&E and KU existing air pollution control technologies for potential upgrades to their performance.

Background

Starting this year and continuing for the next two years, the United States Environmental Protection Agency (USEPA) will be developing and implementing several new environmental regulations. These new regulations will significantly impact our coal-fired electric generating units and will affect all environmental areas of air, water and land. The pollutants targeted in three of the new air regulations are SO_2 and NO_x. There is a recent new 1-hour National Ambient Air Quality Standard (NAAQS) for SO_2 and NO_x that will require lower emission rates at several of the stations and the CAIR rule is proposed to be replace by a new Clean Air Transport Rule (CATR). Each will require additional reductions in SO_2 and NO_x. In 2011, the USEPA is expected to propose and finalize an Electric Utility Maximum Achievable Control Technology Rule (MACT). The MACT rule will require significant reductions in hazardous air pollutants such as mercury and acid gases (i.e., SO_3/H_2SO_4 emissions) which are also emitted from the LG&E and KU coal-fired electric generation fleet.

In May of 2010, Project Engineering was asked to investigate the technological and financial impacts of new environmental air regulations on the KU and LG&E coal-fired units. B&V was hired through a competitive bid process at a contract valued at $149K and given six weeks to provide a high level estimate based on site visits, data collection from the plants and industry experience. As a result of this Phase I effort, approximately $3 billion (escalated) of Air

Emissions Mitigation System additions and retrofits were identified as possible scenarios for bringing the fleet into compliance with the projected standards.

Through the approval of this investment/contract proposal, B&V will be contracted with to continue with Phase II of the engineering and estimating effort. This effort will provide a facility-specific project definition consisting of conceptual designs and budgetary cost estimates for selected air quality control technologies. This effort will result in a Level 1 Engineering assessment for Mill Creek, Ghent and EW Brown. The work for each facility will be staggered with the Mill Creek effort commencing first.

Award of the Phase II work to B&V will provide continuity to the initial study work. The contract will be on a time and material basis, not-to-exceed sole source contract, with a value of $1.6M. Black and Veatch will keep their original team in place to gain efficiencies for the Phase II work. The scope of their work will include activities/deliverables such as the following:

- Kick-Off Meetings at each facility
- Conceptual Design
- Building and Plant Arrangements
- Technology Screening
- Constructability Plans
- Project Cost Estimates including Cash Flows
- Refined Implementation Schedules

The remainder of the investment funding will cover costs of internal labor and expenses and the use of other external engineering /construction firms to review existing air pollution control technology performance enhancement options. Two examples of this would be hiring Riley Power (the original SCR technology firm) to review/model NOx emission reduction improvements on the existing Mill Creek 4 SCR that they originally design in 2002 and their review of improvements to the Mill Creek FGDs similar to the improvements they designed for TC1's FGD improvements as part of the TC2 Project.

Project timeline:

Level I Engineering	**Begin**	**Complete**
Mill Creek	August 2010	March 2011
Ghent	October 2010	April 2011
Brown	January 2011	May 2011

Economic Analysis and Risks

No economic or risk analyses have been performed as this request seeks only sanction to continue refining and developing the scopes, schedules and cost estimates for projects throughout the coal-fired fleet within LG&E and KU to comply with pending air regulations. Each project identified in this continuance of studies will seek sanction independent of this sanction and thus will have economic and risk analyses performed specifically for each project or coal-fired unit.

Assumptions

Assumptions that will be used as a basis for the continuance of analyses performed within this sanction are the Energy Services 2011 MTP Assumptions. The primary assumptions are described in the Background section above.

Financial Summary ($000s)

None performed. This sanction will be capitalized and spread pro-rata across the air compliance projects that are sanctioned in the future.

Cash Flow Comparison ($000s)

Project Expenditures ($Millions)	2010	2011	Total
2010 MTP/LTP	$0.0	$0.0	$0.0
Current Proposal	$.75	$1.25	$2.0

Sensitivities

None performed.

Risks

The 2011 draft MTP includes approximately $3 billion in air compliance projects identified with scope identification, schedules and cost estimates based on minimum (much less than Level I Engineering) engineering analyses. Disapproving this sanction will result in the continuance of generation planning for compliance with pending or proposed air regulations with scopes, schedules and estimates that have a significant margin of error.

Other Alternatives Considered

None

Conclusions and Recommendation

It is the recommendation of Project Engineering and Power Production to approve the continuance of studying and analyzing the scopes and options necessary to comply with pending or proposed air compliance regulations for the KU and LG&E coal-fired generating units. The continuance of these studies will lead to better definition of scopes, implementation schedules and cost estimates of major capital projects to comply with the air regulations that will be incorporated into the 2011 and 2012 MTP plans. Approval is also requested to award B&V a sole source award for $1.6 million on a time-and-material basis for Phase II of the Air Compliance portion of the 2011 MTP.

Eileen Saunders Manager Major Capital Projects	Scott Straight Director Project Engineering
John Voyles VP Transmission & Gen. Services	Ralph Bowling VP Power Production
Paul Thompson SVP Energy Services	Brad Rives Chief Financial Officer
Victor Staffieri Chief Executive Officer	

AUTHORIZATION FOR INVESTMENT PROPOSAL - ORIGINAL

☐ EON U.S. Services Co. ☒ Louisville Gas and Electric Co. ☐ Kentucky Utilities Company

Name of Project: Envir Compliance Study-Air-LGE

Funding Project Type: LGE Steam NonBlnk Excluding Land

Date Requested: 8/5/2010

Project Number: 131693

Budgeted: no

Related Project Numbers:
131694

If unbudgeted, list alternate budget ref. Number(s):
Going before Investment Committee on 8-26-10

Expected Start Date: 1/1/2010

Expected In Service Date: 12/31/2011

Expected Completion Date: 3/31/2012

AIP Prepared by: Mooney, Michael Allen

Phone: 502/627-3671

Project Manager: Saunders, Eileen

Phone: 502/627-2431

Asset Location: Mill Creek Unit 4

Environmental Code: Air

Resp. Center: 002020-GENERATION SUPPORT - LGE

Product Code: 111 - WHOLESALE GENERATION

REASONS AND DETAILED DESCRIPTION OF PROJECT

131693-Envir Compliance Study-Air-LGE

Environmental Compliance Studies - Air for Mill Creek
AIP is requesting $2M for Environmental Air Studies for Mill Creek on LGE (36%), Ghent and Brown (64%) on KU. To be going to IC on 8-26-10.
Approved by IC on 9-3-10

Costs	Capital Investment	Cost of Removal/ Retirement	Capital Cost Subtotal	Inital O&M Cost	Lifetime Maintenance Cost	O&M Cost Subtotal	TOTAL INVESTMENT
	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Contract Labor	$2,000,000.00	$0.00	$2,000,000.00	$0.00	$0.00	$0.00	$2,000,000.00
Subtotal - GAAP	$2,000,000.00	$0.00	$2,000,000.00	$0.00	$0.00	$0.00	$2,000,000.00
Net Expenditures - GAAP	$2,000,000.00	$0.00	$2,000,000.00	$0.00	$0.00	$0.00	$2,000,000.00
Net Expenditures - IFRS	$2,000,000.00	$0.00	$2,000,000.00	$0.00	$0.00	$0.00	$2,000,000.00
2010 Total	$1,250,000.00	$0.00	$1,250,000.00	$0.00	$0.00	$0.00	$1,250,000.00
2011 Total	$750,000.00	$0.00	$750,000.00	$0.00	$0.00	$0.00	$750,000.00
2012 Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Approval Type: Non-IT Projects

Authorized by	Amount	Name	Date Approved	Req'd
Supervisor	$25,000.00			N
Manager	$100,000.00	Clements, Joseph	9/8/2010	Y
Budget Coordinator	$0.00	Ritchey, Stacy		Y
Special Approvers	$0.00	Saunders, Eileen		Y
Budget Coordinator	$0.00	Dowd, Deborah		Y
Director	$300,000.00	Straight, Ronald		Y
Vice President	$750,000.00	Voyles, John		Y
Investment Committee Coordinator	$0.00	Wright, Sharon		Y
Financial Planning Director	$0.00	Garrett, Christopher		Y
Senior Officer	$1,000,000.00	Thompson, Paul		Y
CFO	$1,000,001.00	Rives, Stephen		Y
CEO	$1,000,002.00	Staffieri, Victor		Y
Property Accounting	$0.00	Rose, Bruce		Y

INVESTMENT MATERIALS

UOP #	Utility Account Id		Quantity	Total Cost	
06677	131100	MISCELLANEOUS STRUCTURES (066	0	$720,000.00	

RETIRED EQUIPEMENT (OR MATERIALS)

UOP #	Utility Account Id		Quantity	Vintage Year	Original Project Number

AIP QUESTIONS

Are there Related Project Numbers?
Provide related project numbers or indicate 'N/A'.
131694

Is this an IT related project?
IT project is any project that requires IT involvement or the purchase of hardware and software.
no

Purchase/Sale of Real Estate?
Is this a transaction related to the sale/purchase of land or buildings?
no

Budgeted?
Is the project budgeted or unbudgeted?
no

AIP QUESTIONS

Alternate Budget Numbers?
If the project is unbudgeted, list alternate budget reference numbers. Enter N/A, if none.
Going before Investment Committee on 8-26-10

Legal Asset Retirement Obligation?
Is there a legal or environmental requirement governing disposal of this asset?
no

Leased Asset?
Does this project involve a leased asset?
no

Obsolete Inventory?
Will this project create obsolete inventory?
no

Environmental Project
Is this an Environmental Project?
yes

Environmental Cost Recovery
If an environmental project, is this an approved environmental cost recovery (ECR) project?
yes

ECR Project Type
If this is an ECR project, indicate the project type.
Air

ECR Compliance Number
If this is an ECR project, provide the ECR compliance plan number (see the approved project list on the Rates and Regulatory intranet site).
Not Assigned Yet

Environmental Affairs
Does Environmental Affairs need to review this project for environmental permitting issues (based on responses to the six questions in the Investment Proposal)?
no

Research and Experimental Credit
Is this an experimental project with the purpose of improving, enhancing, or adding to a current manufacturing process?
no

Sales Tax-Pollution Control
Is this project done for environmental regulations or statutes? (If yes, may qualify for the Pollution Control Exemption.)
no

Sales Tax-Manufacturing Integration
Is this project integrated in the Manufacturing Process? (Yes to this question and the following two questions may qualify for the New and Expanded Exemption.)
no

Sales Tax-State Equipment Use
Is this equipment used in the state for the first time?
no

Sales Tax-Upgrade or Improvement?
Is this project considered an upgrade or improvement? If yes, enter description on next line.
no

Sales Tax-Upgrade Description
Description of upgrade, if applicable (i.e., improved materials, increased capacity, longer life, etc.) from prior question. Enter N/A, if not applicable.
N/A

From:	Saunders, Eileen
To:	Straight, Scott
Sent:	8/17/2010 11:36:56 AM
Subject:	2011 MTP Level I Engineering - Air Compliance Projects (Rev 3).docx
Attachments:	2011 MTP Level I Engineering - Air Compliance Projects (Rev 3).docx

Investment Proposal for IC:	August XX, 2010
Project Name:	MTP Engineering – Air Compliance Projects
Total Expenditures:	$2,000K
Project Number:	XXXXXX – LG&E YYYYYY - KU
Business Unit/Line of Business:	LG&E and KU Coal-Fired Generation
Prepared/Presented By:	Scott Straight

Executive Summary

This request seeks authorization of $2,000K to continue refining the scopes, implementation schedules and cost estimates of projects identified in the development of the 2011 MTP as necessary for compliance with proposed or final local, State and Federal air compliance regulations through 2016.

In May of 2010, Project Engineering was asked to investigate the technological and financial impacts of new Environmental Air regulations on the EON U.S. fleet of coal fired units. Black and Veatch was hired through a competitive bid process at a contract valued at $149K and given four to six weeks to provide a high level estimate based on site visits, data collection from the plants and industry experience. As a result of this Phase I effort, approximately $4 billion (escalated) of Air Emissions Mitigation System additions and retrofits were identified as possible scenarios for bringing the fleet into compliance with the projected standards.

Approval of this investment/contract proposal will allow funding of a Phase II engineering and estimating effort that will provide a facility-specific project definition consisting of conceptual designs and budgetary cost estimates for selected air quality control technologies. This effort will result in a Level 1 assessment for the Mill Creek, Ghent and EW Brown facilities. The work for each facility will be staggered with the Mill Creek effort commencing first.

For work product continuity purposes, Project Engineering proposes to award the Phase II work to Black & Veatch on a time and material not to exceed sole source contract, with a value of $1.6M (plus 20 % contingency). Black and Veatch will keep their original team in place to gain efficiencies for the Phase II work. The scope of their work will include activities/deliverables such as the following:

- Kick-Off Meetings at each facility
- Conceptual Design
- Building and Plant Arrangements
- Technology Screening
- Constructability Plans
- Project Cost Estimates including Cash Flows
- Implementation Schedules

The remainder of the investment funding will cover costs of internal labor and expenses and the use of other external engineering /construction firms that may be hired to apply their expert opinions of the constructability of the options put forth by Black and Veatch or to conduct independent assessments as directed by Project Engineering (i.e. BPEI assessing Mill Creek FGD upgrades).

Background

Starting this year and continuing for the next two years, the United States Environmental Protection Agency (USEPA) will be developing and implementing several new environmental regulations. These new regulations will significantly impact our coal-fired electric generating units and will affect all environmental areas of air, water and land. The pollutants targeted in three of the new air regulations are SO_2 and NO_x. There is a recent new 1-hour National Ambient Air Quality Standard (NAAQS) for SO_2 and NO_x that will require lower emission rates at several of the stations and the CAIR rule is proposed to be replace by a new Clean Air Transport Rule (CATR). Each will require additional reductions in SO_2 and NO_x. In 2011, the USEPA is expected to propose and finalize an Electric Utility Maximum Achievable Control Technology Rule (MACT). The MACT rule will require significant reductions in hazardous air pollutants such as mercury and acid gases (i.e., SO_3/H_2SO_4 emissions) which are also emitted from the LG&E and KU coal-fired electric generation fleet.

Project timeline:

Level I Engineering	**Begin**	**Complete**
Mill Creek	August 2010	March 2011
Ghent	October 2010	April 2011
Brown	January 2011	May 2011

Economic Analysis and Risks

No economic or risk analyses have been performed as this request seeks only sanction to continue refining and developing the scopes, schedules and cost estimates for projects throughout the coal-fired fleet within LG&E and KU to comply with pending air regulations. Each project identified in this continuance of studies will seek sanction independent of this sanction and thus will have economic and risk analyses performed specifically for each project or coal-fired unit.

Assumptions

Assumptions that will be used as a basis for the continuance of analyses performed within this sanction are the Energy Services 2011 MTP Assumptions.

Financial Summary ($000s)

None performed. This sanction will be capitalized and spread pro-rata across the air compliance projects that are sanctioned in the future.

Cash Flow Comparison ($000s)

Project Expenditures ($000s)	2010	2011	Total
2010 MTP/LTP	$0.0	$0.0	$0.0
Current Proposal	$.7	$1.2	$2.0

Sensitivities

None performed.

Risks

The 2011 draft MTP includes some $4 billion in air compliance projects identified with scope identification, schedules and cost estimates based on minimum (much less than Level I Engineering) engineering analyses. Disapproving this sanction will result in the continuance of generation planning for compliance with pending or proposed air regulations with scopes, schedules and estimates that have a significant margin of error.

Other Alternatives Considered

None

Conclusions and Recommendation

It is the recommendation of Project Engineering and Power Production to approve the continuance of studying and analyzing the scopes and options necessary to comply with pending or proposed air compliance regulations for the KU and LG&E coal-fired generating units. The continuance of these studies will lead to better definition of scopes, implementation schedules and cost estimates of major capital projects to comply with the air regulations that will be incorporated into the 2011 and 2012 MTP plans.

From: Mahabaleshwarkar, Anand
To: Straight, Scott
CC: Hillman, Timothy M.
Sent: 8/17/2010 2:09:42 PM
Subject: FW: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Attachments: EON AQC Workshop Mill Creek - Meeting Minutes 081010.pdf

FYI

Anand

From: Hillman, Timothy M.
Sent: Tuesday, August 10, 2010 6:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Hillman, Timothy M.
Sent: Tuesday, August 10, 2010 2:18 PM
To: Saunders, Eileen; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Subject: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
When: Wednesday, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
Where: P3A-W (B&V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 10, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION

Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
    - Are they overly conservative?
    - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
    - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.
35. Plant access road and rail tracks are impacted with AQC additions.
36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.
37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.
38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.
39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.
40. Reagent costs are the down side to any DFGD addition to the units.
41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.
42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.
43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.
44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.
45. All pumps are routinely redesign/replaced.
46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.
    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.
47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:
    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.
49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.
50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.
51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.
    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised up from Gary R- during mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			**Average =**	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.001	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.009	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			0	0	0	0.007	0.000	0.000		
							5,056	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994**	**-4,787**	**1,585**					
							Phase I	Phase II						
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	**-**	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	**> 0.5**	**> 0.5**
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

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Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

	MW	Unit	Current Emissions lb/mmBtu	Current Removal %	Future Removal %	Planned future		Preliminary Schedule				Chimney	FF Location
						TECH	Priority	FGD	FF	SCR	Fans		
	330	1	0.48	92	93	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	93	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	94	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

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Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional

New

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include

- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

From:	Sinclair, David
To:	Schram, Chuck; Wilson, Stuart; Brunner, Bob; Pfeiffer, Caryl
Sent:	8/17/2010 5:57:43 PM
Subject:	FW: Project Engineering's ES Bi-Weekly Report - August 16, 2010
Attachments:	PE's Bi-Weekly Update of 8-16-10.docx

fyi

From: Straight, Scott
Sent: Monday, August 16, 2010 9:49 AM
To: Straight, Scott; Thompson, Paul; Voyles, John; Bowling, Ralph; Sturgeon, Allyson; Hudson, Rusty; Hincker, Loren; Sinclair, David; Schetzel, Doug; Yussman, Eric; Jackson, Fred
Cc: Waterman, Bob; Imber, Philip; Lively, Noel; Saunders, Eileen; Gregory, Ronald; Heun, Jeff; Hance, Chuck; Clements, Joe; Cooper, David (Legal); Jones, Greg; Keeling, Chip; Hendricks, Claudia; Ray, Barry; O'brien, Dorothy (Dot); Bellar, Lonnie; Blake, Kent
Subject: RE: Project Engineering's ES Bi-Weekly Report - August 16, 2010

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
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Energy Services - Bi-Weekly Update
August 16, 2010
PROJECT ENGINEERING

- **KU SOx**
    - Safety – Nothing new to report (NTR).
    - Auditing – NTR.
    - Schedule/Execution:
        - Ghent
            - Unit 4 ID Fans – On plan for fall outage.
            - Elevators - Abell Elevator Company has received the contract for their signature.
        - Brown
            - Fluor continues to work on punch-list items and demobilization activities.
            - On plan for Unit 1 outage tie-in.
            - Gypsum slurry sent to de-watering facility on 8/5.
            - Gypsum de-watering operational contract awarded to FPG.
            - MACTEC awarded engineering contract for coal yard extension. Soil borings and engineering have begun.
            - Paving scope bids received.
            - Elevator scope bids received.
    - Budget – NTR.
    - Contract Disputes/Resolution - NTR
    - Issues/Risks – NTR

- **TC2**
    - Safety – NTR
    - Permitting – NTR
    - Auditing – NTR
    - Schedule/Execution:
        - Bechtel EPC – Bechtel has completed installation of the new burner parts. Meetings were held Aug 11-12 with Bechtel and DBEL to discuss operational issues and needed changes for restart. **The unit is behind schedule for the planned restart on Aug 16 due to air balancing issues and erroneous thermocouple readings.**
    - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
    - Contract Disputes/Resolution:
        - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Comments sent to Bechtel on change order draft with expectations of reaching agreement on language of FM and EE claims the week of 8/16.
    - Issues/Risk:
        - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
    - Schedule/Execution – NTR
    - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
    - Engineering – proceeding as planned to support the spring 2012 in-service.
    - Budget - NTR
    - Contracting – NTR
    - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
    - Schedule/Execution –NTR
    - Permitting – NTR
    - Engineering/General:
        - Engineering of Voith scope, automation, historic preservation and de-watering in progress.
    - Budget:
        - NTR
        - Revised project sanction planned for August IC meeting
    - Contracting:
        - Negotiations held with Voith on 8/12-8/13 went very well. PE is still pushing negotiations to support IC review/approval in August, albeit very tight. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
    - Issues/Risk
        - Release of third unit runner to Voith is required in August to maintain schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
    - Safety - NTR
    - Auditing - NTR
    - Permitting - NTR
    - Engineering/General
        - Bids have been received for the maintenance building. PE is reviewing the bids and anticipates an award by 8/31.
        - Working with URS to develop RFQ for long lead equipment. (This process was delayed as options for Mill Creek Air Compliance were explored. Activities associated with ordering the limestone equipment will resume the week of 8/16)
    - Budget
        - AIP complete.
        - Revised cash flow reflected in 2011 MTP
    - Contracting – NTR
    - Issue/Risk – NTR

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.
  - 2010 budget reduced to $1m for this scope with the remainder moving to 2011.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - GSP's Flexible Membrane Liner (FML) and Geo-synthetic Clay Liner (GCL) scheduled to begin in September.
    - Work continues on fill placement and mechanically stabilized earth wall with the north and west dikes substantially completed.
    - Work has begun on both Emergency Spillways.
    - The fiberglass piping for the project has been substantially completed.
  - Budgeting – The $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations may require IC approval. PE is tracking the overall cost of the project against the remaining contingency before seeking increased authorization and revised AIP.
  - Engineering:
    - The study on the GSP clay liner originally installed to compare against potential new regulations has been completed. Path forward is to utilize the existing clay liner as part of a composite liner system.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk
    - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010. The contractor has also submitted financial claims for delays. The claim is being reviewed by PE.
    - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs are being reviewed.
  - Permitting – Both the June and July Anabat studies have been completed for the Indiana Bat. A third party has reviewed the June data and confirmed no findings of the Indiana Bat. The July data is being prepared to be sent to the third party.
  - Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – PE is working with Zachry Engineering to perform a sanity high-level scope and estimate check against the B&V scope and estimate on CCR Transport system. This review is planned to wrap up by the end of August.
  - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCR transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Drawings and Sepcifications for the Detailed Engineering for the Landfill have been submitted for review by EON-US.
  - Permitting – All permit applications have been made. PE is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with the final step in the relocation process being approved by the Carroll County Fiscal Court on 8/10. The relocation will occur in September or October.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk:
    - Land Acquisition – a final offer that discusses condemnation potential was sent to the McDole and Owens land owners. A second letter will be sent to the third remaining land owner the week of 8/16.

- **General CCP Projects**
  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These costs have been included in PE's 2011 MTP draft.
  - PE is working with Legal and US EPA in regards to defense of the KPDES Permit

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – NTR
    - Schedule/Execution:
      - Contract work remains under suspension. Summit demobilized 90% of equipment and performed requested grade work and site stabilization activity.

        - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
      - Budget – NTR
      - Contract Disputes/Resolution: NTR
      - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning 7/6 until further notice.
    - **E.W. Brown Aux Pond 900'**
      - Schedule/Execution:
        - Continued rock embankment blasting at the Houp Property.
        - Began rock embankment placement on the East side foundation.
      - Budget – NTR
      - Contract Disputes/Resolution – NTR
      - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Held teleconferences with Nol-Tek and BCSI – both to provide initial draft of a conformed, redline version of the technical specification and GSA.
    - URS site visit to Ghent held on 8/12. URS to provide commercial response (GSA mark up and guarantee language) the week of 8/16. URS to provide a Ghent 2 technical proposal 9/10. Imber and Straight to visit URS in Austin on 8/23.
    - Sent letters of dismissal to the other three bidders.
      - FLS/CoaLogic – lack of competitive SO3 removal guarantee and the lack of a competitive commercial position regarding the SO3 removal
      - Clyde Bergemann - lack of a competitive the SO3 removal guarantee and no technical advancement
      - UCC – least robust system proposed, lack of confidence in the technical proposal as evaluated by the technical team
    - Path forward to October investment committee is convoluted due to URS submittal and the new options being considered at Mill Creek as a result of the fleet wide environmental studies.
  - Budget – Spending $3M in 2010 is dependent on the procurement process and discussions surrounding delaying MC work.
  - Testing – Contracts prepared but not finalized. Brown and Ghent testing plans published for Aug. 16 – Sep 3:
    - Air Quality Services will be doing testing from 8/16-8/27 at Brown.
    - Clean Air Engineering will be doing testing from 8/16-8/27 at Ghent.
    - EON Engineering will be doing testing from 8/22-9/3 at Ghent.

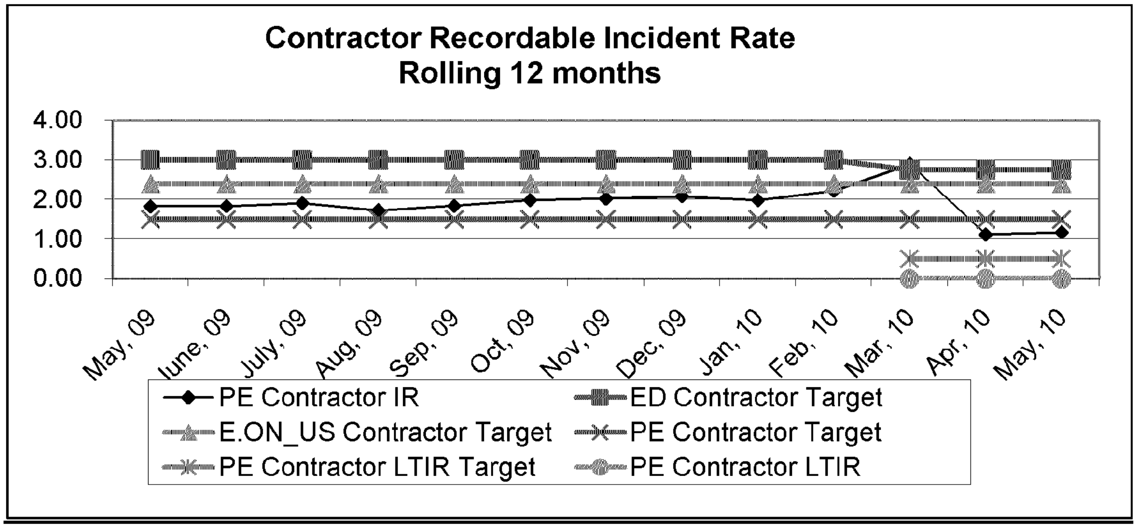
- **SO3 Mitigation (Ghent)**
  - AIPs being processed for each unit for $250k to allow charging of testing/engineering.
  - Preparing for MgO injection at GH4 with Breen. Breen has been at Ghent in preparation of the testing.

  - Calculations for Ghent SAM life cycle reviewed with B&V. Four sets of calculations are being prepared:
    - Base calculation for BACT analysis with all layers of catalyst in place
    - Calculation based on exact operation today.
    - Calculation based on pre-FGD operation with 1.2 lb SO2/mmbtu fuel
    - Calculation pre-SCR operation with 1.2 lb SO2/mmbtu fuel
  - B&V re-draft of BACT analysis and Life Cycle analysis expected week of 8/16
  - B&V requested to prepare two more documents:
    - BACT based on 2005 RBLC database for emissions limits
    - Technology choice based on a 5 ppmv requirement

- **NBU1 and Other Generation Development**
  - LFG - LFG Technologies provided a draft report and updates based on E.ON comment.
  - NBU Cane Run
    - New pro-forma submitted.
    - Outstanding items to be completed: property line drawing and schedule updates
  - Biomass
    - Draft report received with E.ON comments being prepared to release to B&V the week of 8/16.
  - CCS 100 MW Project – Director of Business Development still working on contract with the state. PE in discussion with Battelle, Fluor, Bechtel and EPRI for support of this study work.
  - FutureGen – New project announced in Indiana as a Oxyfuel plant. Path forward for technical committee not identified at this time.

- **General**
  - Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost. Plans are underway to extend the B&V contract to begin discussing various scenarios for compliance with upcoming environmental air regulations. Over $1B removed from Mill Creek Air Compliance after meeting with Kirkland, PE and B&V senior level engineers.
  - Revised Air Compliance cash flows communicated within ES on 8/13. The three scenarios are for a 2014, 2015 and 2016 CATR with all three scenarios having a 1-year delay on HAPs to 2017.
  - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A revised recommendation will be presented to officers within ES the week of 8/6/10.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Jason Finn has submitted for positions.
3. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From:	Lively, Noel
To:	Straight, Scott
Sent:	8/25/2010 7:08:27 AM
Subject:	PE's Bi-Weekly Update of 8-27-10.docx
Attachments:	PE's Bi-Weekly Update of 7-30-10.docx

Energy Services - Bi-Weekly Update
Aug 27, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Chimney Coatings – Testing of the coating application remain.
      - SCR/FGD Icing Siding – Installation nearing completion.
      - Unit 4 ID Fans – An outage kickoff meeting is planned for 8/4/10.
      - Chimney Capping – Caps placed by helicopter on both chimneys on 7/25/10.
      - Elevators - Award Recommendation is circulating for signatures.
    - Brown
      - The FGD continues to operate very well.
      - E.W. Brown Gypsum Dewatering Facility
        - Product to be sent to the facility next week for final commissioning activity. This was delayed a week due to high ash content in gypsum stream.
        - Facility operation award recommendation being routed for signatures.
      - E.W. Brown Coal Pile Modification
        - Bid received for engineering from MACTEC and PO under development.
      - Balance of Project Items
        - Paving scope out for bid
        - Elevator scope out for bid
  - Budget – Slight reduction in the total Brown FGD Program ITC to $408.8m.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks - NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – Burner test run of Aug 20 was unsuccessful since slagging was still evident. Burner damage was avoided and the E-row burners were fitted with the pumpkin tooth modification. Another test run is scheduled for Aug 25 that will include increased secondary air. If this is successful, then all burners will be revised with this modification and possibly with a further modification of "ski ramps" at the burner tip, depending on timing of delivery. **We are still working towards a substantial completion date of 10/12/10.** This impact to commissioning was communicated through a formal letter to KYPSC.

  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Change order is in progress.
  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
  - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Schedule/Execution –NTR
  - Permitting – NTR
  - Engineering/General:
    - Reviewing Voith updated scope for rehabilitation minus automation.
    - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
  - Budget:
    - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
    - Revised project sanction planned for August IC meeting
  - Contracting:
    - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR
  - Engineering/General
    - Pre-bid meeting for the building extension work was held at Mill Creek on July 8, 2010 and bids were received July 23, 2010.
    - Working with URS to develop RFQ for long lead equipment.

  - Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
  - Contracting – NTR
  - Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
    - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
    - Work has begun on both Emergency Spillways.
    - Working continues on the fiberglass piping for the project
  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.

  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk
    - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
    - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
  - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
  - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCP transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Detailed Engineering for the Landfill is focusing on completion of construction drawings.
  - Permitting – All permit applications have been made. Project Engineering is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with planning with the local authorities and the cemetery where the remains will be relocated.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk:
    - Land Acquisition – a final offer that will discuss condemnation potential will be sent to the remaining three land owners in early July. A final recommendation will be presented to management for approval on whether to change designs or condemn the remaining property in late July.

- **General CCP Projects**
  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential

additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
  - Safety – NTR
  - Schedule/Execution:
    - Work on Phase I is being suspended until a decision is made on whether to convert the main pond to a landfill.
    - Working on evaluation and recommendation paper for the main pond conversion from a pond to a landfill .
    - Aux Pond Phase II work awarded to Charah.
  - Budget – NTR
  - Contract Disputes/Resolution - NTR
  - Issues/Risk – A decision is required in July on whether to continue with the Main Pond or convert to a dry landfill. Economics indicate conversion now to be least cost compared to continuing with pond and then converting once regulations are final.

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension except for rock embankment placement, dust control, and general site maintenance.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
      - Rock placement continued on the West and South Embankments.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Installation of erosion and sediment control measures.
      - Topsoil stockpiles were relocated.
      - Began rock embankment blasting at the Houp Property.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Proposals for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI received July 20.
    - Bid review meetings held with stations and all suppliers July 26 & 28.

        - Initial team evaluation sheets due COB Friday July 30. Summary discussion meeting to be set the week of Aug. 2.
        - Bid Summary – dry system pricing ranges from $2.2 to $6.3M per system with numerous clarifications and further engineering to be performed and evaluated. **Meaningful pricing not submitted for the wet system.**
            - URS – only offered core technology equipment, no BOP, no construction. 2 ppmv guarantee at the stack with LD to 10% of equipment cost
            - Nol-Tec – turn-key offer, similar to our existing systems with substantial upgrades. 2 ppmv guarantee with LD to contract price
            - BCSI – turnkey in concept, construction partners not finalized (systems pre-packaged to minimize on site fabrication). Highly redundant process, similar to our existing systems with upgrades. 1.9 ppmv guarantee with LD to contract price
            - UCC – turnkey, system designed to minimize cost at every point, 1 ppmv guarantee offered with LD to contract price. Based on our experience their proposal is not a technically sound offer.
            - FLS – turnkey, we are not familiar with the construction partners, 5 ppmv guarantee with LD to 20% contract price
            - Clyde Bergemann – turnkey system, similar to our existing systems but equipment is sized small, 3-5 ppmv guarantee (not firm in the discussion) and not firm on extent of LD.
        - All vendors owe further information/clarification by COB Tuesday August 4.
        - Path forward to October investment committee is convoluted due to URS submittal. Planning to pick 1 or 2 dry vendor systems to continue commercial and technical conformance. Likely hire URS to perform an engineering study to price Ghent 2 (with common systems sized for all Ghent units).
    - Budget – Spending $3M in 2010 is dependent on the procurement process and discussions surrounding delaying MC work.
    - Testing – Contracts need to be placed and test plans need to be prepared on the following:
        - Notify Air Quality Services that they will be doing testing from 8/16-8/27 at Brown.
        - Notify Clean Air Engineering that they will be doing testing from 8/16-8/27 at Ghent.
        - Notify EON Engineering that they will be doing testing from 8/22-9/3 at Ghent.

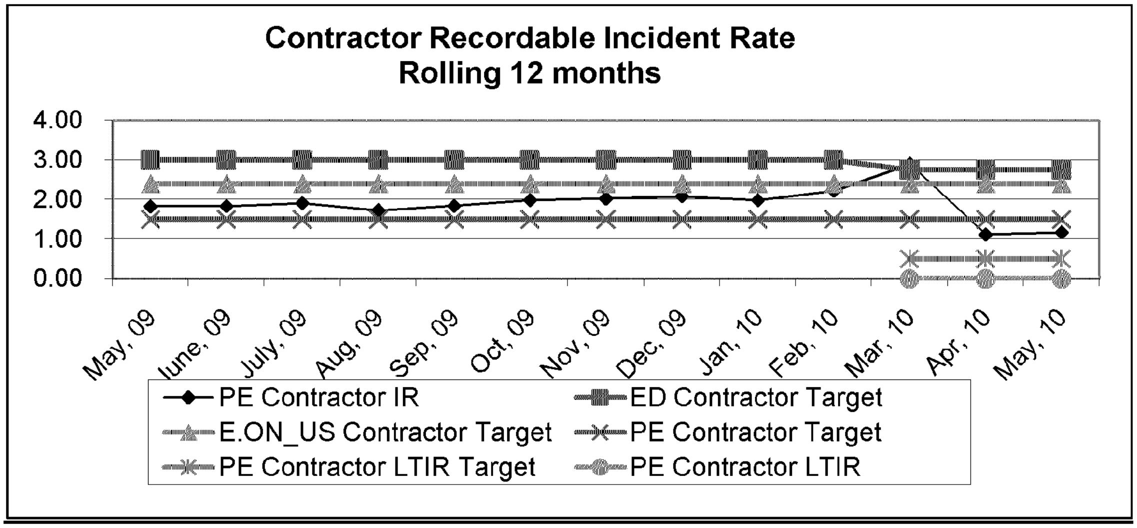
- **SO3 Mitigation (Ghent)**
    - Preparing for MgO injection at GH4.
    - Stoic Calculations for Ghent testing prepared.
    - B&V reworking SAM calculations for the Ghent Units based on Title V Heat Inputs..
    - B&V draft BACT analysis submitted and commented by E.ON.
    - B&V requested to prepare two more documents:
        - BACT based on 2005 RBLC database for emissions limits
        - Technology choice based on a 5 ppmv requirement

- **NBU1 and Other Generation Development**
    - LFG
        - Landfill Gas Sample Result completed – final sample report outstanding.
        - LFG Technologies completed landfill visits.

    - Draft report expected week of August 2.
  - NBU CR – Complete draft of documents submitted July 20. E.ON comments submitted July 28. Final draft expected week of August 2.
  - Biomass –
    - Complete draft report from B&V due the week of August 2.
    - Moore Ventures completed a fuel analysis assessment.
  - CCS 100 MW Project – Prepared a SOW and RFP for study work regarding a DOE/State/E.ON project. Submitted comment to presentation to DOE. Project will not get funding for a 2016 100 MW project – as such internal work ceased prior to releasing RFP to Bechtel, Fluor, Battelle, and EPRI.
  - FutureGen – NTR

- **General**
  - Impoundment Integrity Program – PE is transitioning this to Generation Services.
  - Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost. Plans are underway to extend the B&V contract to begin discussing various scenarios for compliance with upcoming environmental air regulations.
  - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A revised recommendation will be presented to officers within ES the week of 8/6/10.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Philip Imber has submitted for two postings outside of ES.
3. Jason Finn has submitted for positions.
4. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From:	Saunders, Eileen
To:	Kirkland, Mike; Revlett, Gary; Imber, Philip; Gregory, Ronald
CC:	Straight, Scott
Sent:	8/26/2010 7:48:35 AM
Subject:	FW: 15.0200 100819 Mill Creek AQC Workshop of Aug 5-6 - Final Meeting Minutes
Attachments:	Mill Creek AQC Workshop Aug 5-6 - Conf Memo Final 081910.pdf

All,

Here are the final minutes from the Workshop on August 5-6 issued by B&V.

Thank you,

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Thursday, August 19, 2010 2:46 PM
To: Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: 15.0200 100819 Mill Creek AQC Workshop of Aug 5-6 - Final Meeting Minutes

Scott,

As we discussed in our Tuesday (8/17) conference call, please find attached final meeting minutes from our Mill Creek AQC Workshop of August 5th and 6th.

Best Regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Hillman, Timothy M.
Sent: Monday, August 16, 2010 8:18 AM
To: 'Straight, Scott'
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Scott,

Please find attached a revised table indicating 96 percent removal for the refurbished scrubbers. We also made a slight revision to the AQC schematic and cost table, adding a key to the legend indicating that Unit 1's ESP would be removed.

We look forward talking to you tomorrow during our conference call.

Best regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services

Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Straight, Scott [mailto:Scott.Straight@eon-us.com]
Sent: Thursday, August 12, 2010 1:34 PM
To: Hillman, Timothy M.; Saunders, Eileen
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Tim,

The targeted SO2 removal for the Unit 1, Unit 2 and Unit 4 (to serve Unit 3) FGDs is 96%, not 93%. They are doing this now at times.

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040
scott.straight@eon-us.com

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
ıgust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 19, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION
Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
   - Are they overly conservative?
   - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
   - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.
35. Plant access road and rail tracks are impacted with AQC additions.
36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.
37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.
38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.
39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.
40. Reagent costs are the down side to any DFGD addition to the units.
41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.
42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.
43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.
44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.
45. All pumps are routinely redesign/replaced.
46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.
    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.
47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:
    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.
49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.
50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.
51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.
    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised up from Gary R- during Mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	I NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			Average =	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.009	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.007	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			**5,056**	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

		2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
Plant	Unit	SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994**	**-4,787**	**1,585**					
							Phase	Phase						
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	-	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	> 0.5	> 0.5
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

			Current Emissions	Current Removal	Future Removal	Planned future		Preliminary Schedule					
	MW	Unit	lb/mmBtu	%	%	TECH	Priority	FGD	FF	SCR	Fans	Chimney	FF Location
	330	1	0.48	92	96	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	96	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	96	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

Rev 1, 100813

Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional
New
Removed

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include
- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

Rev 1, 100813

From: Gregory, Ronald
To: Saunders, Eileen
Sent: 8/26/2010 11:31:09 AM
Subject: PE's Bi-Weekly Update of 8-26-10 (rdg).docx
Attachments: PE's Bi-Weekly Update of 8-26-10 (rdg).docx

Energy Services - Bi-Weekly Update
August 27, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Unit 4 ID Fans – On plan for fall outage.
      - Elevators - Abell Elevator Company has received the contract for their signature.
    - Brown
      - Fluor continues to work on punch-list items and demobilization activities.
      - On plan for Unit 1 outage tie-in.
      - Fluor is nearing completion of work with ABB to design and install logic and graphic modifications to provide enhanced automatic operation of the BR2 ID and FD fans and dampers. This work will be implemented, tested and commissioned during the scheduled BR2 Fall 2010 outage.
      - Gypsum De-watering
        - Minor checkout issues pertaining to the takeaway conveyor and radial stacker require field modification.
        - Facility operational contract awarded to FPG, whose labor continues to support the commissioning effort when needed.
      - E.W. Brown Coal Pile Modification
        - MACTEC continues engineering design.
        - KU transmission performed site visit to plan the rerouting of power feeds to the coal yard lighting and retention pond sump pumps.
      - Paving scope has been awarded to Asphalt Paving & Maintenance, Inc. and is scheduled to be completed by mid September.
      - Elevator scope has been awarded to United Group Services, Inc. and is scheduled to be completed by the end of February next year.
  - Budget – The Brown FGD Program Current Budget with Fluor this period is at $490.4m. There is $1.7m included in the forecast for un-approved change orders and $3.9m included in the forecast for the "Non-Target" structural reinforcement work. The current month Fluor forecast for Brown was reduced by $104k, for a Total Brown FGD Program ITC of $408.7m..
  - Contract Disputes/Resolution - NTR
  - Issues/Risks – NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:

    - Bechtel EPC – Bechtel has completed installation of the new burner parts. Meetings were held Aug 11-12 with Bechtel and DBEL to discuss operational issues and needed changes for restart. **The unit is behind schedule for the planned restart on Aug 16 due to air balancing issues and erroneous thermocouple readings.**
- Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
- Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Comments sent to Bechtel on change order draft with expectations of reaching agreement on language of FM and EE claims the week of 8/16.
- Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – NTR
  - Issues/Risk – NTR

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    - Engineering of Voith scope, automation, historic preservation and de-watering in progress.
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    - Revised project sanction planned for August IC meeting
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    - Negotiations held with Voith on 8/12-8/13 went very well. PE is still pushing negotiations to support IC review/approval in August, albeit very tight. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR
  - Engineering/General
    - Bids have been received for the maintenance building. PE is reviewing the bids and anticipates an award by 8/31.
    - Working with URS to develop RFQ for long lead equipment. (This process was delayed as options for Mill Creek Air Compliance were explored. Activities associated with ordering the limestone equipment will resume the week of 8/16)
  - Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
  - Contracting – NTR
  - Issue/Risk – NTR

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
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  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
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  - 2010 budget reduced to $1m for this scope with the remainder moving to 2011.

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    - GSP's Flexible Membrane Liner (FML) and Geo-synthetic Clay Liner (GCL) scheduled to begin in September.
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    - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCR transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Drawings and Sepcifications for the Detailed Engineering for the Landfill have been submitted for review by EON-US.
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        - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
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  - AIPs being processed for each unit for $250k to allow charging of testing/engineering.

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    - Base calculation for BACT analysis with all layers of catalyst in place
    - Calculation based on exact operation today.
    - Calculation based on pre-FGD operation with 1.2 lb SO2/mmbtu fuel
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  - Revised Air Compliance cash flows communicated within ES on 8/13. The three scenarios are for a 2014, 2015 and 2016 CATR with all three scenarios having a 1-year delay on HAPs to 2017.
  - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

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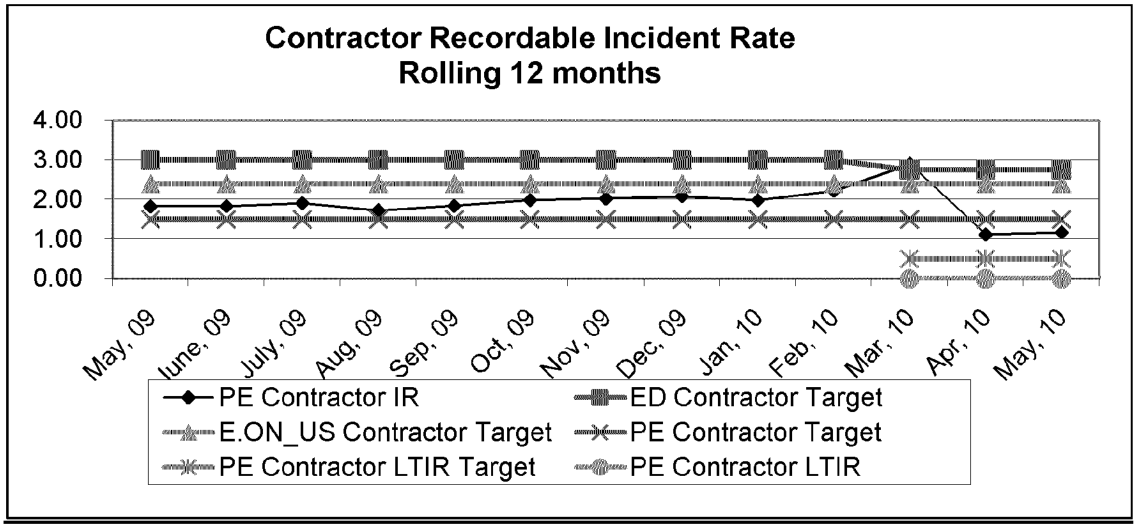

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2. Jason Finn has submitted for positions.
3. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From: Saunders, Eileen
To: Straight, Scott
CC: Gregory, Ronald; Saunders, Eileen
Sent: 8/26/2010 1:54:47 PM
Subject: PE's Bi-Weekly Update of 8-26-10 (rdg-els).docx
Attachments: PE's Bi-Weekly Update of 8-26-10 (rdg-els).docx

Scott,

Here is the report for Brown and Ghent.

Thanks,

Eileen

Energy Services - Bi-Weekly Update
August 27, 2010
PROJECT ENGINEERING

- **KU SOx**
    - Safety – The Ghent FGD Program has achieved 4.5 million safe work hours. A safety celebration will take place on September 2, 2010 at the Ghent Station.
    - Auditing – NTR.
    - Schedule/Execution:
        - Ghent
            - Unit 4 ID Fans – On plan for fall outage.
            - Elevators - Abell Elevator Company has received the contract for their signature.
            - Siding project nearing completion.
        - Brown
            - Fluor continues to work on punch-list items and demobilization activities.
            - On plan for Unit 1 outage tie-in.
            - Fluor is nearing completion of work with ABB to design and install logic and graphic modifications to provide enhanced automatic operation of the BR2 ID and FD fans and dampers. This work will be implemented, tested and commissioned during the scheduled BR2 Fall 2010 outage.
            - Gypsum De-watering
                - Minor checkout issues pertaining to the takeaway conveyor and radial stacker require field modification.
                - Facility operational contract awarded to FPG, whose labor continues to support the commissioning effort when needed.
            - E.W. Brown Coal Pile Modification
                - MACTEC continues engineering design.
                - KU transmission performed site visit to plan the rerouting of power feeds to the coal yard lighting and retention pond sump pumps.
            - Paving scope has been awarded to Asphalt Paving & Maintenance, Inc. and is scheduled to be completed by mid September.
            - Elevator scope has been awarded to United Group Services, Inc. and is scheduled to be completed by the end of February next year.
    - Budget – The Brown FGD Program Current Budget with Fluor this period is at $490.4m. There is $1.7m included in the forecast for un-approved change orders and $3.9m included in the forecast for the "Non-Target" structural reinforcement work. The current month Fluor forecast for Brown was reduced by $104k, for a Total Brown FGD Program ITC of $408.7m..
    - Ghent Budget: NTR
    - Contract Disputes/Resolution - NTR
    - Issues/Risks – NTR

- **TC2**
    - Safety – NTR
    - Permitting – NTR

- Auditing – NTR
- Schedule/Execution:
    - Bechtel EPC – Bechtel has completed installation of the new burner parts. Meetings were held Aug 11-12 with Bechtel and DBEL to discuss operational issues and needed changes for restart. **The unit is behind schedule for the planned restart on Aug 16 due to air balancing issues and erroneous thermocouple readings.**
- Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
- Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Comments sent to Bechtel on change order draft with expectations of reaching agreement on language of FM and EE claims the week of 8/16.
- Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
    - Schedule/Execution – NTR
    - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
    - Engineering – proceeding as planned to support the spring 2012 in-service.
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        - Revised project sanction planned for August IC meeting
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    - Issues/Risk
        - Release of third unit runner to Voith is required in August to maintain schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
    - Safety - NTR
    - Auditing - NTR
    - Permitting - NTR
    - Engineering/General
        - Award recommendation to East and Westbrook is in the signature stage.
        - Metso proposal is in the review process. Initial technical comments/clarifications have been forwarded back to Metso through URS. Commercial review is also underway.
    - Budget
        - AIP complete.
        - Revised cash flow reflected in 2011 MTP
    - Contracting – NTR
    - Issue/Risk – NTR

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- Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. To date permitting process has gone well.
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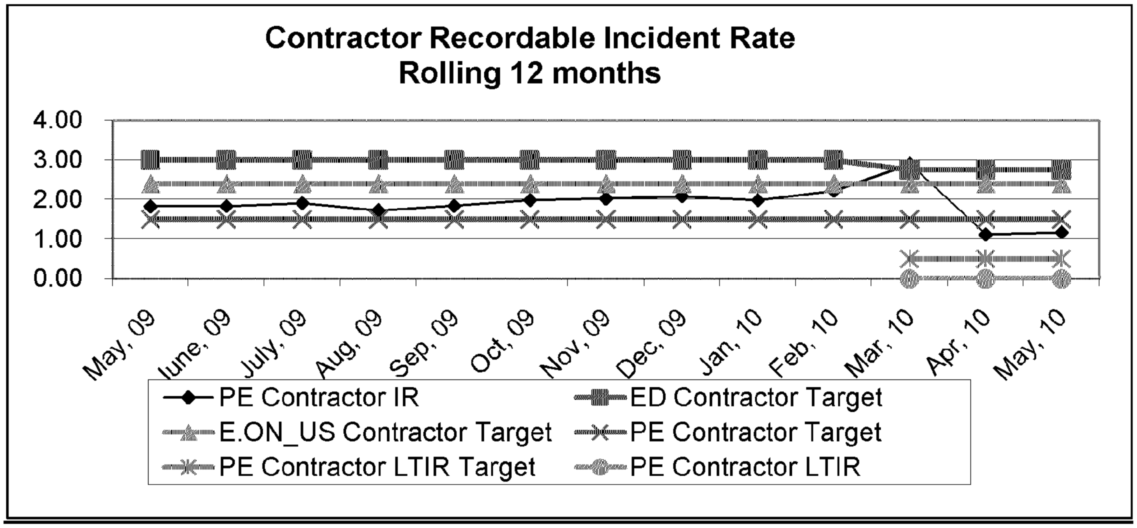

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From: Hillman, Timothy M.
To: Saunders, Eileen; Straight, Scott
CC: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Sent: 8/10/2010 7:47:00 PM
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Attachments: EON AQC Workshop Mill Creek - Meeting Minutes 081010.pdf

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Hillman, Timothy M.
Sent: Tuesday, August 10, 2010 2:18 PM
To: Saunders, Eileen; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Subject: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
When: Wednesday, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
Where: P3A-W (B&V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 10, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION

Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
    - Are they overly conservative?
    - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
    - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.
35. Plant access road and rail tracks are impacted with AQC additions.
36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.
37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.
38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.
39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.
40. Reagent costs are the down side to any DFGD addition to the units.
41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.
42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.
43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.
44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.
45. All pumps are routinely redesign/replaced.
46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.
    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.
47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:
    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.

49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.

50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.

51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.

    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised up from Gary R- during mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

		2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
Plant	Unit	SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			**Average =**	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.001	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.009	0.000	0.000		
							0	0	0	0.007	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			**5,056**	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	(lbs/mmBtu) SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994** Phase I	**-4,787** Phase	**1,585**					
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	**-**	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	> 0.5	> 0.5
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

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Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

	MW	Unit	Current Emissions lb/mmBtu	Current Removal %	Future Removal %	Planned future TECH	Planned future Priority	Preliminary Schedule FGD	Preliminary Schedule FF	Preliminary Schedule SCR	Preliminary Schedule Fans	Chimney	FF Location
	330	1	0.48	92	93	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	93	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	94	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

DRAFT

Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional

New

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include
- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

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From:	Saunders, Eileen
To:	Karavayev, Louanne
Sent:	8/26/2010 5:01:35 PM
Subject:	FW: 15.0200 100819 Mill Creek AQC Workshop of Aug 5-6 - Final Meeting Minutes
Attachments:	Mill Creek AQC Workshop Aug 5-6 - Conf Memo Final 081910.pdf

LouAnne,

We will focus on the final page of this document for our discussion tomorrow.

Thanks,

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Thursday, August 19, 2010 2:46 PM
To: Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: 15.0200 100819 Mill Creek AQC Workshop of Aug 5-6 - Final Meeting Minutes

Scott,

As we discussed in our Tuesday (8/17) conference call, please find attached final meeting minutes from our Mill Creek AQC Workshop of August 5th and 6th.

Best Regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Hillman, Timothy M.
Sent: Monday, August 16, 2010 8:18 AM
To: 'Straight, Scott'
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Scott,

Please find attached a revised table indicating 96 percent removal for the refurbished scrubbers. We also made a slight revision to the AQC schematic and cost table, adding a key to the legend indicating that Unit 1's ESP would be removed.

We look forward talking to you tomorrow during our conference call.

Best regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™

11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Straight, Scott [mailto:Scott.Straight@eon-us.com]
Sent: Thursday, August 12, 2010 1:34 PM
To: Hillman, Timothy M.; Saunders, Eileen
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Tim,

The targeted SO2 removal for the Unit 1, Unit 2 and Unit 4 (to serve Unit 3) FGDs is 96%, not 93%. They are doing this now at times.

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040
scott.straight@eon-us.com

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
ıgust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
/, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 19, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION

Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
   - Are they overly conservative?
   - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
   - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.
35. Plant access road and rail tracks are impacted with AQC additions.
36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.
37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.
38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.
39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.
40. Reagent costs are the down side to any DFGD addition to the units.
41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.
42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.
43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.
44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.
45. All pumps are routinely redesign/replaced.
46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.
    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.
47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:
    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.

49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.

50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.

51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.

    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised ~~up~~ from Gary R- during Mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	I NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			Average =	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.009	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.007	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			**5,056**	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

		2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
Plant	Unit	SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994**	**-4,787**	**1,585**					
							Phase	Phase.						
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	-	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	**> 0.5**	**> 0.5**
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

						Planned future		Preliminary Schedule					
	MW	Unit	Current Emissions lb/mmBtu	Current Removal **%**	Future Removal **%**	**TECH**	**Priority**	**FGD**	**FF**	**SCR**	**Fans**	**Chimney**	**FF Location**
	330	1	0.48	92	96	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	96	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	96	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

Rev 1, 100813

Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional

New

Removed

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include

- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

Rev 1, 100813

From:	Saunders, Eileen
To:	Karavayev, Louanne
Sent:	8/26/2010 5:03:07 PM
Subject:	FW: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Attachments:	EON cost Analysis Mill Creek Upgrade Final Rev 1.pdf

This should help as well. I will send the MTP stuff in the morning since I am leaving for a meeting in a few minutes.

Thanks,

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Monday, August 16, 2010 9:18 AM
To: Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Saunders, Eileen
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Scott,

Please find attached a revised table indicating 96 percent removal for the refurbished scrubbers. We also made a slight revision to the AQC schematic and cost table, adding a key to the legend indicating that Unit 1's ESP would be removed.

We look forward talking to you tomorrow during our conference call.

Best regards,

Tim Hillman | Project Manager
Power Generation - Environmental Services
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

From: Straight, Scott [mailto:Scott.Straight@eon-us.com]
Sent: Thursday, August 12, 2010 1:34 PM
To: Hillman, Timothy M.; Saunders, Eileen
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work

Tim,

The targeted SO2 removal for the Unit 1, Unit 2 and Unit 4 (to serve Unit 3) FGDs is 96%, not 93%. They are doing this now at times.

Scott Straight, P.E.
Project Engineering - E.ON U.S.
Director, Project Engineering
O (502) 627-2701
F (502) 217-2040

scott.straight@eon-us.com

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
igust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
/, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

			Current Emissions	Current Removal	Future Removal	Planned future		Preliminary Schedule					
		Uncontrolled SO2	6.2	lb/Mmbtu									
	MW	Unit	lb/mmBtu	%	%	TECH	Priority	FGD	FF	SCR	Fans	Chimney	FF Location
	330	1	0.48	92	96	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	96	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	96	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

Rev 1, 100813

Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
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Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
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Optional
New
Removed

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include
- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

Rev 1, 100813

From:	Lively, Noel
To:	Straight, Scott
Sent:	8/27/2010 7:47:22 AM
Subject:	FW: PE's Bi-Weekly Update of 8-27-10.docx
Attachments:	PE's Bi-Weekly Update of 7-30-10.docx

Scott,

I had already sent it, but I've updated it.

Noel

From: Lively, Noel
Sent: Wednesday, August 25, 2010 7:08 AM
To: Straight, Scott
Subject: PE's Bi-Weekly Update of 8-27-10.docx

Energy Services - Bi-Weekly Update
Aug 27, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Chimney Coatings – Testing of the coating application remain.
      - SCR/FGD Icing Siding – Installation nearing completion.
      - Unit 4 ID Fans – An outage kickoff meeting is planned for 8/4/10.
      - Chimney Capping – Caps placed by helicopter on both chimneys on 7/25/10.
      - Elevators - Award Recommendation is circulating for signatures.
    - Brown
      - The FGD continues to operate very well.
      - E.W. Brown Gypsum Dewatering Facility
        - Product to be sent to the facility next week for final commissioning activity. This was delayed a week due to high ash content in gypsum stream.
        - Facility operation award recommendation being routed for signatures.
      - E.W. Brown Coal Pile Modification
        - Bid received for engineering from MACTEC and PO under development.
      - Balance of Project Items
        - Paving scope out for bid
        - Elevator scope out for bid
  - Budget – Slight reduction in the total Brown FGD Program ITC to $408.8m.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks - NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – Burner test run of Aug 20 was unsuccessful since slagging was still evident. Burner damage was avoided and the E-row burners were fitted with the pumpkin tooth modification. Test run in progress that includes increased secondary air. If this is successful, then all burners may be revised with this modification and possibly with a further modification of “ski ramps” at the burner tip, unless the planned run on unmodified B-row burners is successful following the E-mill run, which would demonstrate the main issue was air flow. **We are still working towards a substantial completion date of 10/12/10.** This impact to commissioning was communicated through a formal letter to KYPSC.

  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Change order is in progress.
  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
  - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Schedule/Execution –NTR
  - Permitting – NTR
  - Engineering/General:
    - Reviewing Voith updated scope for rehabilitation minus automation.
    - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
  - Budget:
    - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
    - Revised project sanction planned for August IC meeting
  - Contracting:
    - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR
  - Engineering/General
    - Pre-bid meeting for the building extension work was held at Mill Creek on July 8, 2010 and bids were received July 23, 2010.
    - Working with URS to develop RFQ for long lead equipment.

  - Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
  - Contracting – NTR
  - Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
    - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
    - Work has begun on both Emergency Spillways.
    - Working continues on the fiberglass piping for the project
  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.

  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk
    - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
    - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
  - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
  - Engineering – Detailed Engineering of gypsum fines continues with Black & Veatch. Bids have been received and currently under review for the CCP transport Detailed Design. Procurement activities for the gypsum fines project are in progress. Detailed Engineering for the Landfill is focusing on completion of construction drawings.
  - Permitting – All permit applications have been made. Project Engineering is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with planning with the local authorities and the cemetery where the remains will be relocated.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk:
    - Land Acquisition – a final offer that will discuss condemnation potential will be sent to the remaining three land owners in early July. A final recommendation will be presented to management for approval on whether to change designs or condemn the remaining property in late July.

- **General CCP Projects**
  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential

additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
  - Safety – NTR
  - Schedule/Execution:
    - Work on Phase I is being suspended until a decision is made on whether to convert the main pond to a landfill.
    - Working on evaluation and recommendation paper for the main pond conversion from a pond to a landfill .
    - Aux Pond Phase II work awarded to Charah.
  - Budget – NTR
  - Contract Disputes/Resolution - NTR
  - Issues/Risk – A decision is required in July on whether to continue with the Main Pond or convert to a dry landfill. Economics indicate conversion now to be least cost compared to continuing with pond and then converting once regulations are final.

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension except for rock embankment placement, dust control, and general site maintenance.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
      - Rock placement continued on the West and South Embankments.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Installation of erosion and sediment control measures.
      - Topsoil stockpiles were relocated.
      - Began rock embankment blasting at the Houp Property.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Proposals for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI received July 20.
    - Bid review meetings held with stations and all suppliers July 26 & 28.

        - Initial team evaluation sheets due COB Friday July 30. Summary discussion meeting to be set the week of Aug. 2.
        - Bid Summary – dry system pricing ranges from $2.2 to $6.3M per system with numerous clarifications and further engineering to be performed and evaluated. **Meaningful pricing not submitted for the wet system.**
            - URS – only offered core technology equipment, no BOP, no construction. 2 ppmv guarantee at the stack with LD to 10% of equipment cost
            - Nol-Tec – turn-key offer, similar to our existing systems with substantial upgrades. 2 ppmv guarantee with LD to contract price
            - BCSI – turnkey in concept, construction partners not finalized (systems pre-packaged to minimize on site fabrication). Highly redundant process, similar to our existing systems with upgrades. 1.9 ppmv guarantee with LD to contract price
            - UCC – turnkey, system designed to minimize cost at every point, 1 ppmv guarantee offered with LD to contract price. Based on our experience their proposal is not a technically sound offer.
            - FLS – turnkey, we are not familiar with the construction partners, 5 ppmv guarantee with LD to 20% contract price
            - Clyde Bergemann – turnkey system, similar to our existing systems but equipment is sized small, 3-5 ppmv guarantee (not firm in the discussion) and not firm on extent of LD.
        - All vendors owe further information/clarification by COB Tuesday August 4.
        - Path forward to October investment committee is convoluted due to URS submittal. Planning to pick 1 or 2 dry vendor systems to continue commercial and technical conformance. Likely hire URS to perform an engineering study to price Ghent 2 (with common systems sized for all Ghent units).
    - Budget – Spending $3M in 2010 is dependent on the procurement process and discussions surrounding delaying MC work.
    - Testing – Contracts need to be placed and test plans need to be prepared on the following:
        - Notify Air Quality Services that they will be doing testing from 8/16-8/27 at Brown.
        - Notify Clean Air Engineering that they will be doing testing from 8/16-8/27 at Ghent.
        - Notify EON Engineering that they will be doing testing from 8/22-9/3 at Ghent.

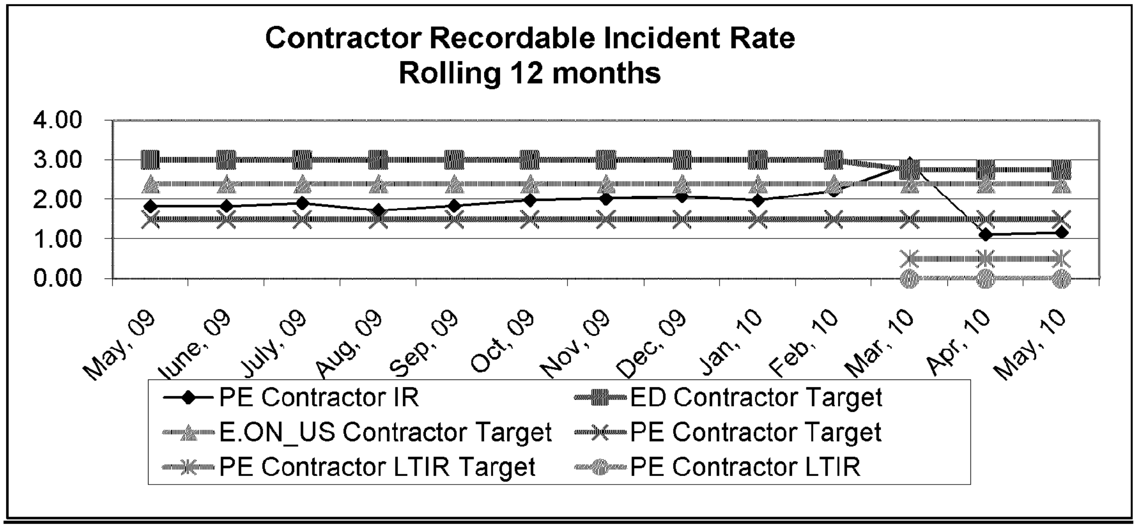
- **SO3 Mitigation (Ghent)**
    - Preparing for MgO injection at GH4.
    - Stoic Calculations for Ghent testing prepared.
    - B&V reworking SAM calculations for the Ghent Units based on Title V Heat Inputs..
    - B&V draft BACT analysis submitted and commented by E.ON.
    - B&V requested to prepare two more documents:
        - BACT based on 2005 RBLC database for emissions limits
        - Technology choice based on a 5 ppmv requirement

- **NBU1 and Other Generation Development**
    - LFG
        - Landfill Gas Sample Result completed – final sample report outstanding.
        - LFG Technologies completed landfill visits.

        - Draft report expected week of August 2.
    - NBU CR – Complete draft of documents submitted July 20. E.ON comments submitted July 28. Final draft expected week of August 2.
    - Biomass –
        - Complete draft report from B&V due the week of August 2.
        - Moore Ventures completed a fuel analysis assessment.
    - CCS 100 MW Project – Prepared a SOW and RFP for study work regarding a DOE/State/E.ON project. Submitted comment to presentation to DOE. Project will not get funding for a 2016 100 MW project – as such internal work ceased prior to releasing RFP to Bechtel, Fluor, Battelle, and EPRI.
    - FutureGen – NTR

- **General**
    - Impoundment Integrity Program – PE is transitioning this to Generation Services.
    - Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost. Plans are underway to extend the B&V contract to begin discussing various scenarios for compliance with upcoming environmental air regulations.
    - Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A revised recommendation will be presented to officers within ES the week of 8/6/10.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Philip Imber has submitted for two postings outside of ES.
3. Jason Finn has submitted for positions.
4. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From:	Saunders, Eileen
To:	Kirkland, Mike; Gregory, Ronald; Revlett, Gary; Imber, Philip
CC:	Straight, Scott
Sent:	8/11/2010 10:06:38 AM
Subject:	FW: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Attachments:	EON AQC Workshop Mill Creek - Meeting Minutes 081010.pdf

All,

Here are the notes from the workshop you participated in last week. Please review and let me know if you have any comments.

Thanks,

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, August 10, 2010 7:47 PM
To: Saunders, Eileen; Straight, Scott
Cc: Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike); Wehrly, M. R.; Ballard, Michael W; Lucas, Kyle J.; Hillman, Timothy M.
Subject: RE: E.ON Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
Importance: High

Scott and Eileen,

Please find attached the draft meeting minutes and spreadsheet with schematic and costs from our AQC Workshop last Thursday and Friday in your office. We look forward to reviewing this with you during our conference call on Wednesday (2 pm your time).
Best regards,

Tim Hillman | Project Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-7928**
Email: **hillmantm@bv.com**

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nothy M.
igust 10, 2010 2:18 PM
en; Wehrly, M. R.; Straight, Scott; Mahabaleshwarkar, Anand; Lausman, Rick L.; Harris, David K. (Dave); King, Michael L. (Mike)
Conference Call - Review Workshop Meeting Minutes and Next Phase Scope of Work
/, August 11, 2010 1:00 PM-2:00 PM (GMT-06:00) Central Time (US & Canada).
V Folks)

Call in number

877-603-8688

Conf ID: 8791684

BLACK & VEATCH CORPORATION
CONFERENCE MEMORANDUM

E.ON US	B&V Project 167987
AQC Evaluation Project	B&V File 15.0200
Mill Creek Workshop Meeting	August 10, 2010

An AQC Technology Screening Meeting for Mill Creek (MC) was held on August 5th and 6th at E.ON's Broadway Office Complex in Louisville, Kentucky.

Recorded by: Rick Lausman/Tim Hillman

Attending:

E.ON US

Scott Straight	Dir. Proj. Engin
Phillip Imber	Sr. Chem. Eng
Ronald Gregory	Mgr Major Project
Gary Revlett (Aug 5 Only, part time)	Mgr Air Section
Mike Kirkland	Mill Creek Plt Mgr

Black & Veatch

Tim Hillman	Proj Mgr
Mike Ballard	Oper Mgr. Constr.
Anand Mahabaleshwarkar	AQCS
Rick Lausman	AQCS

The purpose of the meeting was to provide a workshop for discussing the retrofit AQC costs and strategy for the Mill Creek plant.

DISCUSSION

Day 1, August 5, 2010

1. The meeting began with introductions and distribution of the agenda (attached herein for reference).
2. E.ON reviewed the major issues for discussion during the AQC workshop. Two (2) billion dollars was the cost developed by B&V for the Mill Creek facility during the Phase I study in July 2010. The Mill Creek units alone were approximately half of the fleet-wide AQC costs estimated in the Phase I study.
    - Are they overly conservative?
    - Need to prioritize Mill Creek unit AQC additions in light of future regulations.
3. E.ON wants to look at various combinations to reduce the costs for the AQC retrofit, including wet, dry, and hybrid SO2 removal technologies.

MILL CREEK SITE SPECIFIC

4. E.ON provided a matrix of the potential emission limits and regulations for Mill Creek entitled Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations (attached herein for reference).
    - Shaded items in the table represent final rules.

- E.ON has final SAM BART determination for MC3 and MC4, with no specific implementation date specified. MC1 and MC2 were not affected. E.ON expects BART implementation to coincide with Title V Operating Permit Renewal in mid 2011.
- It may be possible for E.ON to get an extension of the BART SAM implementation date if they go forward with additional AQC controls.
- CATR compliance date for first round of allowances is 2012. E.ON is targeting 2014 for SO2 CATR controls for all 4 MC units, while trying to negotiate a schedule relief for SAM BART implementation.
- E.ON believes MC controls will primarily be focused on Hg, SAM, and SO2. NOx compliance is thought to be satisfactory for MC, although MC4's SCR requires improvement. SCRs for MC1 and MC2 will only be necessary in the event a fleet-wide NOx compliance margin is necessary.

5. E.ON provided a document entitled KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx for discussion (attached herein for reference).
6. Regulators called a meeting last week with E.ON. An SO2 monitor within a couple of blocks of the plant already has shown exceedances of the new 1–hr limit.

NOx ISSUES

7. In general, E.ON believes that MC's existing NOx controls will meet proposed CATR and NAAQS requirements, although MC4's SCR will need improved performance.
8. NOx controls also likely in 2016 – concern is mostly CATR not NAAQS. Limit is tons/year with an annual limitation.
9. E.ON reported that MC 4 SCR is limited compared to MC 3 and needs some upgrades. MC 3 initially did not meet limits, but they added some more mixers since they had the fan, so now it is one of the best SCRs in the country. That is where Unit 4 needs to go.
10. Brown 3 getting SCR for 2013 and then Ghent 2 would be the next target, so Mill Creek U1 and U2 SCRs may not be needed. Cane Run – repowering with combined cycle by 2016.
11. MC 4 may be only SCR changes at Mill Creek. E.ON is looking at improving SCR and improving staging O2 in furnace, which creates a reducing atmosphere. Plant is currently overlaying the boiler tubes to handle this.
12. No other NOx changes for Mill Creek. This means MC1 and MC2 do not necessarily need SCRs from a facility perspective, but may be considered in the future to allow margin from fleet-wide perspective. MC2 would be the easiest to add an SCR to since it is on the end of the line of the units. **E.ON wants to keep space available for MC1 and MC2 SCRs just in case they are required in the future.**

SO2 ISSUES

13. Mill Creek can not easily switch to and burn PRB because fan/air issues.
14. For SO2, the real driver at MC is the new 1-hour NAAQS. 2016 end of year is when NAAQS standard must be met, but regulators will try to push that out further. Nearby SO2 ambient monitors are already indicating problems with the new 1-hour standard. The state has already contacted E.ON inquiring about what they intend to do about it. Currently, MC is emitting approximately 0.5 lb/MBtu (facility average), but air dispersion

modeling indicates MC needs to be about 0.25 lb/MBtu on average to be in compliance with NAAQS.

15. Plant is currently running about 0.6 lb/MBTU emissions on 6.2 lb/MBtu fuel. This equates to approximately 90 percent removal.
16. It is uncertain how the NAAQS will be implemented – will regulators allow a 24-hr emission limit, or a 1-hr limit.
17. The plant will need to see an overall FGD removal efficiency of 95 -96 percent for compliance with a 6.2 lb/MBtu fuel.
18. CATR does not allow old credits to be used for new program. Dates for compliance are set for 2012. Regulators may provide some relief.
19. The fleet wide SO2 emissions are sufficiently low with respect to the first phase of CATR in 2012, so SO2 may not be a worry until 2014.

HAPS ISSUES

20. With respect to Hg and MACT regulatory compliance, E.ON reports that ICR tests are just finishing up at four stations. Based on the initial ICR test results, EON estimates that MC will require Hg control, and believes that acid gases are probably alright at approximately 95 percent control. Hg will be an issue at Mill Creek; MC3 and MC4 will be close to the limit.
21. Regulators may allow plant-wide averaging for Hg, but this is uncertain.
22. E.ON reports that Trimble 1 and 2 98 percent scrubbers are getting 91-92 percent Hg removal.
23. Acid gas emissions should be compliant at Mill Creek.
24. Metals emissions are also low at Mill Creek with FGD.

BYPRODUCT ISSUES

25. Mill Creek needs to be able to sell ash due to landfill limitations.
26. E.ON worried about water emission issues and future limitations that may be forthcoming that would impact the site.

SITE/UNIT SPECIFIC ISSUES

27. Major outages allowed every 8 years (8 weeks). Most of these longer outages are in the next couple of years. Typical outages are 4 weeks in other years. The spring of 2014 outage is MC 4's major outage.
28. MC1 and 2 had trays added in 2002 which are now wearing thin. All duct work needs replaced. Top of modules need to be placed.
29. MC 3 and 4 FGD had trays added in 2000.
30. MC 4 top of modules and duct work needs to be replaced.
31. MC 4 contact trays were initially installed with thinner trays to save cost, but have thinned further due to erosion and also need replacement.
32. Do not necessarily need to replace the pumps on the units. MC 1 and 2 had some pumps replaced previously.
33. E.ON reports all scrubbers are basically in a constant rebuilding mode, and are generally good for another 20 years structurally speaking.

34. Do not necessarily need to replace the recycle piping on the units. MC 1 and 2 had most replaced.
35. Plant access road and rail tracks are impacted with AQC additions.
36. If access road area is required for AQC equipment location, then access during construction becomes an issue. May have to cut in to coal pile storage area for construction/plant access.
37. New FGDs will require approximately the same or more aux power than the existing equipment. Assume the units will need new fans. CDS or NIDS technology has about 6-7" w.g. pressure drop across reactor, while spray dry absorber may be less.
38. Rail Tracks – Four tracks currently run along the access road. One set has been abandoned, and only the two inner tracks are used. The two outer tracks could be demolished.
39. Water/Wastewater – DFGD would have less impact on water and landfill issues. Currently, the wastewater is routed to the ash ponds.
40. Reagent costs are the down side to any DFGD addition to the units.
41. E.ON reports that chlorine is going up in the Illinois basin coals, so DFGDs would be beneficial because of their acid gas removal capability. High chlorides will also impact the wastewater stream that is currently going to ash ponds.
42. MC1 and MC2 need replacement of the top of the scrubber modules. All duct work has been replaced that wasn't replaced during the wet stack conversion.
43. MC4 top of scrubber module needs replacement. Duct work needs replacement, and trays are thin and need replacement.
44. MC3 scrubber structure is good, although mixing is poor. MC3 also has the underground reaction tanks and recycle pumps, which cause maintenance and reliability issues.
45. All pumps are routinely redesign/replaced.
46. Rick Lausman (B&V) led a discussion and presentation of alternative FGD technologies for new systems and for upgrading existing units.
    - E.ON questioned if Mill Creek had to reduce water emissions for chlorides and metals with wastewater treatment, what would be a rule of thumb cost? B&V noted that they would need to get an answer from their Chemical section.
    - Skipped much of the WFGD to get to Semi-Dry discussion.
    - Of the semi-dry FGD technologies, the Alstom NIDs system would allow most flexibility from a site retrofit aspect because it is modular and has less footprint impact.
47. Various AQCS upgrade and retrofit scenarios were discussed for the station. As the result of discussions during the workshop, the technology scenario deemed to provide the best balance of cost and performance was as follows:
    - Build a new WFGD for MC4.
    - Upgrade MC4's existing WFGD and use it for MC3.
    - Upgrade MC1 and MC2's existing WFGDs.
    - Add fabric filters to all four units.
    - Add PAC for Hg control.

- Add duct injection systems for SO3 control.
- As an alternative to the fabric filter, add NID system.

Day 2, August 6, 2010

48. E.ON reported that after yesterday's meeting, that they had talked to B&W and Babcock Power about the having them look at MC 1 & 2 for estimates about what it would take to modify the units to improve performance.

49. Support systems are reported to be satisfactory for limestone slurry. Dewatering should be satisfactory, but could be reviewed. Much of the piping has been replaced during maintenance over the last several years.

50. There is an 8 week outage in 2011 on Unit 2 that may be utilized for part of the FGD upgrade.

51. Anand Mahabaleshwarkar (B&V) lead a white board discussion focused on developing high-level costs of the scenario discussed in the item 47 above. A spreadsheet that captures the results of the discussion and provides information on the following is attached herein for reference.

    - Schematics of the AQC scenarios
    - Priorities
    - High-level costs
    - Schedule
    - Performance targets

ACTION ITEMS

- Provide rule of thumb costs for wastewater treatment if chlorides and metals in wastewater require reduction.

Attachments:

- Agenda
- Estimated Coal-fired Boiler Air Emission Limits Under Future Environmental Regulations.
- KU and LG&E Modeled Emissions Requirements Under CATR and NAAQS for SO2 and NOx
- Spreadsheet schematic and $/kW costs

cc: All Attendees
File

AGENDA

AQC Technology Screening Workshop
E.ON - Mill Creek Station
August 5th and 6th, 2010
(8:30 am – 4:00 pm)
Location: E.ON Broadway Office Complex

Day 1, Aug 5th

I. Introductions

II. Mill Creek Site-Specific Issues

III Review Phase I Study Results/Background/Conclusions

IV. Technology Overview Presentation

V. Pros and Cons of AQC Technologies Applied to Mill Creek

Day 2, Aug 6th

VI. Constructability Challenges

VII. High Level Cost Estimate (Interactive during the workshop)

VIII. Workshop Conclusions - Next Steps

Adjourn

Revised
Gary
Handout

Estimated Coal-fired Boiler Air Emission Limits under Future Environmental Regulations

Program Name	Regulated Pollutants		Coal -fired Power Plants						Forcasted Date for Compliance
	Pollutant	Units	Brown	Ghent	Green River	Cane Run	Mill Creek	Trimble	
BART	MC3 - SAM	lbs/hour	-	-	-	-	MC3 - 64.3 MC4 - 76.5	-	Within 6 months of final Title V
New 1-hour NAAQS for NO_x	NO_x	lbs/mmBtu	> 0.5	0.47	0.56	0.07	0.39	> 0.5	2016 2015 - 2017
New 1-hour NAAQS for SO_2	SO_2	lbs/mmBtu	> 0.4	0.31	0.15	0.06	0.25	> 0.5	2016
Clean Air Transport Rule (CATR)*	NO_x	lbs/mmBtu	0.145	0.041	0.314	0.315	0.114	0.047	Beginning in 2012 & Phase II in 2014
	SO_2		0.108	0.186	0.887	0.187	0.311	0.162	
New EGU MACT	Mercury	Removal lbs/GWH	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	90% or 0.012	Estimated January, 2015; with 1-yr extension - January, 2016
	Acids (HCl)	lbs/mmBtu	0.002	0.002	0.002	0.002	0.002	0.002	
	Metals (PM)	lbs/mmBtu	0.03	0.03	0.03	0.03	0.03	0.03	
	Metals (As)	lbs/mmBtu	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	0.5×10^{-5}	
	Organics (CO)	lbs/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	
	Dioxin/Furan	lbs/mmBtu	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	15×10^{-18}	

☐ - Regulation or requirements are final

* - Intrastate Cap & Trade Program with KU and LG&E estimated total being: 22,832 t/y NO_x in 2012; 65,235 t/y SO_2 in 2012; and 41,774 t/y SO_2 in 2014.

Revised up from Gary R- during Mtng

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

Plant	Unit	2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
		SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	NO_x-2015
KU														
Brown	1	3,452.4	606.2	2,591,990	2.66	0.47	2,851	795	1,346	1.530	0.203	0.372		
Brown	2	6,726.2	903.27	5,098,318	2.64	0.35	678	650	1,913	0.211	0.108	0.318		
Brown	3	22,070.9	2,716.10	16,803,275	2.63	0.32	1,525	1,463	915	0.164	0.093	0.058		
				Average=	**2.63**	**0.35**			Average =	**0.318**	**0.108**	**0.145**	> 0.4	> 0.5
Brown CT	5	0.0	2.4	64,040	0.00	0.07	0	0	0	0.001	0.000	0.000		
Brown CT	6	0.1	19.2	510,439	0.00	0.08	0	0	0	0.001	0.000	0.000		
Brown CT	7	0.2	12.7	328,815	0.00	0.08	2	0	0	0.008	0.000	0.000		
Brown CT	8	0.0	8.9	132,139	0.00	0.13	0	0	0	0.001	0.000	0.000		
Brown CT	9	0.0	2.3	41,253	0.00	0.11	0	0	0	0.001	0.000	0.000		
Brown CT	10	0.2	3.5	48,766	0.01	0.14	0	0	0	0.009	0.000	0.000		
Brown CT	11	0.2	5.3	80,331	0.00	0.13	0	0	0	0.007	0.000	0.000		
Brown	**Total**	**32,250.2**	**4,279.9**	**25,699,366**			**5,056**	**2,908**	**4,174**					
						expected emissions =	**1,726**	**1,746**	**3,062**					
						bank =	**3,330**	**1,162**	**1,112**					
Ghent	1	1,418.1	973.2	31,802,243	0.09	0.06	2,221	3,653	794	0.139	0.214	0.050		
Ghent	2	5,044.3	2,664.9	24,783,886	0.41	0.22	2,101	1,813	976	0.180	0.108	0.058		
Ghent	3	3,188.6	1,972.3	34,425,557	0.19	0.11	3,578	3,363	483	0.199	0.203	0.030		
Ghent	4	1,220.5	802.8	28,668,181	0.09	0.06	1,214	3,359	468	0.079	0.203	0.029		
Ghent	**Total**	**10,871.5**	**6,413.2**	**119,679,867.3**	**0.18**	**0.11**	**9,114**	**12,188**	**2,721**	**0.155**	**0.186**	**0.041**	**0.31**	**0.47**
						expected emissions =	**11,480**	**11,381**	**7,833**					
						bank =	**-2,366**	**807**	**-5,112**					
Green River	4	5,447.7	525.7	2,580,883	4.22	0.41	5,215	1,153	890	4.029	0.887	0.310		
Green River	5	9,276.3	894.0	4,595,734	4.04	0.39	9,447	2,854	1,159	3.882	0.887	0.316		
Green River	**Total**	**14,724.0**	**1,419.7**	**7,176,617**	**4.10**	**0.40**	**14,662**	**4,007**	**2,049**	**3.955**	**0.887**	**0.314**	**0.15**	**0.56**
						expected emissions =	**14,467**	**15,654**	**1,916**					
						bank =	**195**	**-11,647**	**133**					
Tyrone	5	203.7	77.1	325,548	1.25	0.47	1,634	1,180	610	1.312	0.593	0.307		
Tyrone	**Total**	**203.7**	**77.1**	**325,548**	**1.25**	**0.47**	**1,634**	**1,180**	**610**	**1.312**	**0.593**	**0.307**		
						expected emissions =	**0**	**0**	**0**					
						bank =	**1,634**	**1,180**	**610**					
KU	**Total**	**58,049**	**12,190**	**152,881,398**	**0.76**	**0.16**	**30,466**	**20,283**	**9,554**	**0.399**	**0.265**	**0.125**		
						Expected Emissions =	**27,673**	**28,782**	**12,811**					
						Bank =	**2,793**	**-8,499**	**-3,257**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

KU and LG&E Modeled Emission Requirements under CATR and NAAQS for SO_2 and NO_x

		2009 Actual Emissions					CATR Allocation Tons			CATR Alterative lb/mmBtu			NAAQS Modeling (lbs/mmBtu)	
Plant	Unit	SO_2 (tons)	NO_x (tons)	mmBtu (year)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2 for 2012	SO_2 for 2014	NO_x in ≥ 2012	SO_2-2016	NO_x-2015
LGE														
Cane Run	4	2,158.2	1,770.0	10,295,729	0.42	0.34	1,930	821	1,724	0.371	0.161	0.339		
Cane Run	5	2,099.9	2,020.0	10,259,979	0.41	0.39	1,918	918	1,763	0.345	0.161	0.310		
Cane Run	6	4,534.0	1,948.4	13,442,706	0.67	0.29	4,801	2,039	2,497	0.685	0.227	0.301		
Cane Run	**Total**	**8,792.1**	**5,738.4**	**33,998,414**	**0.517**	**0.34**	**8,649**	**3,778**	**5,984**	**0.487**	**0.187**	**0.315**	**0.06**	**0.07**
						expected emissions =	**7,655**	**8,565**	**4,399**					
						bank =	**994** Phase I	**-4,787** Phase	**1,585**					
Mill Creek	1	3,731.8	3,127.0	19,477,664	0.38	0.32	3,562	2,666	2,722	0.393	0.239	0.241		
Mill Creek	2	4,122.8	2,991.6	18,829,209	0.44	0.32	4,444	3,021	2,648	0.424	0.268	0.235		
Mill Creek	3	8,215.0	777.6	28,372,378	0.58	0.05	8,366	3,725	621	0.601	0.300	0.043		
Mill Creek	4	8,164.4	1,010.7	36,428,449	0.45	0.06	8,249	6,044	704	0.461	0.379	0.040		
Mill Creek	**Total**	**24,234.0**	**7,906.9**	**103,107,700**	**0.470**	**0.15**	**24,621**	**15,456**	**6,695**	**0.480**	**0.311**	**0.114**	**0.25**	**0.39**
						expected emissions =	**24,977**	**24,149**	**8,433**					
						bank =	**-356**	**-8,693**	**-1,738**					
Paddy's Run	13	0.0	0.5	12,730	0	0.079	0.0	0.0	0.0	0.001	0.000	0.000		
Paddy's Run	**Total**	**0.0**	**0.5**	**12,730**	-	**0.08**	**0.0**	**0.0**	**0.0**	0.001	0.000	0.000		
Trimble Co.	1	1,216.6	1,110.7	30,713,328	0.079	0.072	1,499	2,257	599	**0.078**	**0.162**	**0.047**	> 0.5	> 0.5
Trimble Co. CT	5	0.1	7.0	479,506	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	6	0.0	5.7	323,359	0.000	0.035	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	7	0.0	5.8	398,057	0.000	0.029	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	8	0.1	5.9	388,797	0.001	0.030	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	9	0.0	5.2	304,087	0.000	0.034	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble Co. CT	10	0.0	4.6	242,941	0.000	0.038	0.0	0.0	0.0	0.001	0.000	0.000		
Trimble	**Total**	**1,216.8**	**1,144.9**	**32,850,075.0**	**0.074**	**0.07**	**1,499**	**2,257**	**599**					
						expected emissions =	**3,561**	**3,615**	**1,763**					
						bank =	**-2,062**	**-1,358**	**-1,164**					
LG&E	**Total**	**34,243**	**14,791**	**169,968,919**	**0.403**	**0.174**	**34,769**	**21,491**	**13,278**	**0.409**	**0.253**	**0.156**		
						Expected Emissions =	**36,193**	**36,329**	**14,595**					
						Bank =	**-1,424**	**-14,838**	**-1,317**					
KU + LG&E	**Total**	**92,292**	**26,981**	**322,850,317**	**0.572**	**0.167**	**65,235**	**41,774**	**22,832**	**0.404**	**0.259**	**0.141**		
						Expected Emissions =	**63,866**	**65,110**	**27,406**					
						Bank =	**1,369**	**-23,336**	**-4,574**					

Expected emissions from Generation Planning, 2010728_Emissions_by_Unit_by_Month_30Yrs.xlsx. Value for 2012 is the average of 2012 2013.

DRAFT

Mill Creek Conceptual AQCS Compliance Preliminary Scenario Summary
August 5 &6, 2010 Workshop Results

Uncontrolled SO2 6.2 lb/Mmbtu

			Current Emissions	Current Removal	Future Removal	Planned future		Preliminary Schedule					
	MW	Unit	lb/mmBtu	%	%	TECH	Priority	FGD	FF	SCR	Fans	Chimney	FF Location
	330	1	0.48	92	93	FGD- up	1	2012 U	2014	2016	2014	Existing	In road
	330	2	0.48	92	93	FGD- up	4	2013 or 4th - 2013	2013	2015	2013	Existing	To open area north
	425	3	0.36	86	94	Unit 4 FGD	3	1st Qtr 2014	APR - 2015		2015	Existing	Road with fans in Unit 3 FGD area
	525	4	0.12	92	98	New FGD	2	4th - 2013	4th - 2013	Relocate NH3	2013	Likely New	South side of plant
Summary	1610		0.36										
		Target	lb/mmBtu	0.25		% Removal	96.0						

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Mill Creek Conceptual AQCS Compliance Scenarios and Costs
August 5 &6, 2010 Workshop Results

Unit 1															
330	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/Kw	294				13		24	245		125			701	$/kw
	$ x 1000	97,020				4,290		7,920	80,850		41,250			231,330	Total, $ x 1000
W NIDS	$/Kw	294				13			450		125			882	$/kw
	$ x 1000													291,060	Total, $ x 1000
Unit 2	MW														
330		SCR		AH	ESP - N	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- R				
									NID						
W/O NIDS	$/KW	294			100	13		24	245		125			801	$/kw
	$ x 1000	97,020			33,000	4,290		7,920	80,850	0	41,250			264,330	Total, $ x 1000
W NIDS	$/Kw	294			100	13			450		125			982	$/kw
	$ x 1000													324,060	Total, $ x 1000
Unit 3															
425	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- RU4				
									NID			Demolition			
W/O NIDS	$/Kw	0			0	13		24	245		150	60		492	$/kw
	$ x 1000	0				5,525		10,200	104,125		63,750	25,500		209,100	Total, $ x 1000
W NIDS	$/Kw	0			0	13			450		150	60		673	$/kw
	$ x 1000													286,025	Total, $ x 1000
Unit 4															
525	MW	SCR		AH	ESP	PAC	ID Fan	SO3	FF	Bstr. Fan	WFGD- N	Chimney			
		Upgrades	NH3 and Site						NID				Demolition		
W/O NIDS	$/Kw	10	20		0	13		24	250	0	400	50	0	767	$/kw
	$ x 1000	5,250	10,500			6,825		12,600	131,250		210,000	26,250		402,675	Total, $ x 1000
W NIDS	$/Kw	10	20		0	13			500	0	400	50	0	993	$/kw
	$ x 1000													521,325	Total, $ x 1000

Optional
New

TOTAL COST	Without NIDS	1,107,435	$ x 1000
	With NIDS	1,422,470	$ x 1000

FGD Capital Cost Include
- Inlet and outlet duct
- Ductwork
- Recycle Pumps
- Spray Levels
- Flow Devices/Tray/Rings
- ME
- Shell material
- Structural Steel
- Fans
- Recondition Support Steel
- Aux Power
- Unit 2 topshell upgrade needs to be looked at since plant had taken that out of budget

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From:	Jackson, Fred
To:	Thompson, Paul
CC:	Voyles, John
Sent:	8/11/2010 4:09:10 PM
Subject:	Draft Energy Services Major Projects Report - June-July 2010
Attachments:	Energy Services Major Projects Monthly Report June-July 2010 Draft .docx; PE's Bi-Weekly Update of 7-2-10.docx; PE's Bi-Weekly Update of 7-30-10.docx

Paul,

Attached is a draft of the June-July 2010 ES Major Projects Monthly Report. All updates are shown as tracked changes against the May report you sent to Vic. I have ***not*** mentioned the potential increase in cost for the transport system on Ghent CCP Project or the potential Cane Run CCGT impact on Cane Run CCP project.

I also attached the July 2 and July 31 Project Engineering Bi-Weekly Updates as reference. Please let me know if questions.

Thanks,
Fred

Energy Services Major Projects Monthly Report
June-July 2010

I. KU SOx Program

A. Safety

No Issues to report.

B. Schedule

Ghent 3: Mechanically complete. Shakedown activities are continuing and moving towards final contract settlement, including LD claims. Operationally, the re-engineered ID fan bearing replacement made in June is operating satisfactorily but continues under close monitoring.

Ghent 4: Mechanically complete. Second rewound ID fan motor installed and placed into service. Planning to install FlaktWoods axial fans in September 2010 outage.

Ghent 1: Mechanically complete.

Ghent Site: Restoration projects in progress.

Brown: FGD tie-in to Unit 3 successfully completed May 21. FGD now in service for Unit 3 only. Units 1 and 2 operational on plan to be placed in service later this year.

C. Budget

Ghent 3: No Material Change.

Ghent 4: No Material Change.

Ghent 1: No Material Change.

Brown: Currently forecasting a positive variance to budget of greater than $50M.

D. Issues/Risks

ID Fan Bearing issues as noted above. FlaktWoods and Flour have signed the Final Settlement Term Sheet. Finalized trade of one Brown ID fan motor for spare blades for two fans at Ghent. Blades received at Ghent. WEG (Subcontractor to FlaktWoods) ID Fan motor inspection complete. Motor is expected to be on site before GH4 scheduled outage in fall 2010.

Significant icing and fogging experienced on Ghent 1 FGD from Ghent 2 Cooling Tower. Contract awarded for siding on Ghent Unit 1 SCR and FGD. Work in progress.

Ghent FGDs experiencing numerous leaking valves. Replacement of valves is planned.

II. Trimble County 2

A. Safety

No Issues to report.

B. Schedule

Achieved 50% load on June 17. Significant combustion issues have resulted in significant damage to approximately half of the 30 burners. A root cause failure investigation is in progress by burner vendor. The unit is scheduled to restart in mid August and COD revised to October 12, 2010.

C. Budget

Sanction amount is $964.5M. Forecasted costs at 8 to 9% above sanction.

D. Issues/Risks

Schedule as noted above. Force Majeure claims on weather events still under discussion.

Discussion on Bechtel Excusable Event letters in progress.

Bechtel cancelled air blows based on no strategic value. Reviewing a change order to recover associated reduced costs.

Significant combustion issues as noted above.

Delayed COD.

III. Brown Ash Pond

A. Safety

No issues to Report

B. Schedule

Work on Phase I of the Main Pond is on hold pending potential impact of proposed coal combustion products regulations.

C. Budget

No Material Change

D. Issues/Risks

Potential impact of proposed coal combustion products regulations as noted above.

IV. KU NOx Program (Brown 3)

A. Safety

No issues to Report

B. Schedule

Technology agreement executed December 9, 2009.
EPC contract awarded to Zachary May 19 including assignment of technology purchase agreement.

C. Budget

No material change.

D. Issues/Risks

Timeliness of permits to construct.

V. Trimble County Coal Combustion Products

A. Safety

No issues to Report

B. Schedule

See Issues/Risks below

C. Budget

No Material Change

D. Issues/Risks

State in process of responding to comments from public hearing on KPDES permit.

Meeting long term on site disposal needs is a schedule concern based engineering/construction and permitting. CCN issued December 23, 2009.

Negotiating with U.S. Fish and Wildlife on mitigation plan for Indiana Bat.

Holcim contract negotiations for beneficial reuse have resumed.

Resolved an issue with GAI (Consultant) associated with costs for the mechanical engineering scope of the Bottom Ash Pond/Gypsum Pond work.

VI. Ghent Coal Combustion Products

A. Safety

No Issues to Report

B. Schedule

See Issues/Risks below. All permit applications submitted.

C. Budget

No Material Change

D. Issues/Risks

Meeting on site disposal needs is a schedule concern based on timeline associated land acquisition, permitting, and engineering/construction. CCN issued December 23, 2009. Review of potential modifications to landfill design to eliminate need for these three properties complete. Final offers being prepared for remaining three landowners.

VII. Cane Run Coal Combustion Products

A. Safety

No issues to Report

B. Schedule

404/401 and Special Waste Landfill permit applications submitted to KY Division of Water and KY Division of Waste Management, respectively.

C. Budget

No Material Change

D. Issues/Risks

Meeting on site disposal needs is a schedule concern based on timeline associated with permitting and engineering/construction. No land acquisition expected under current construction plan.

Based on updated CCP production rates, the maximum life of the proposed landfill is 16 years.

Energy Services - Bi-Weekly Update
July2, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – Internal Auditing has issued the final draft of the Brown FGD audit with zero significant findings.
  - Schedule/Execution:
    - Ghent
      - Chimney Coatings – Testing of the coating application remain.
      - SCR/FGD Icing Siding – Installation nearing completion.
      - Unit 4 ID Fans – On plan for fall 2010 install. Fluor mobilizing to the site.
      - Chimney Capping – Work to begin July 6th.
      - Elevators- Bids higher than anticipated but within budget. New schedules and higher cost being accounted for in the 2011 MTP.
    - Brown
      - The FGD continues to operate very well.
      - E.W. Brown Gypsum Dewatering Facility
        - Commissioning nearing completion, the system is running.
        - Facility operation contract bid reviews ongoing.
      - E.W. Brown Gypsum Lab
        - Construction almost complete.
  - Budget - NTR.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks - NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – TC2 achieved 50% load Jun 15th. Bechtel has experienced significant combustion issues that have resulted in significant damage to about half of the 30 burners. The Root Cause Analysis (RCA) has not been issued but Doosan claims the Dodge Hill coal has a high Free Swelling Index, meaning the coal becomes plastic as it burns resulting in heavy slagging in the burner. It appears likely that we will have to resume commissioning on an alternate fuel while Doosan redesigns the burners for our fuel box post commissioning or until Bechtel changes to another vendor's burners. **Bechtel's anticipates restarting the unit mid-August with a new substantial completion date of Oct 8.** This impact to commissioning was communicated through a formal letter to KYPSC.
  - Budget – NTR
  - Contract Disputes/Resolution:
    - Bechtel FM Claims – Parked at the present time by both parties.

  - Issues/Risk:
    - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
  - Schedule/Execution – NTR
  - Permitting – waiting on permit to construct pending resolution of SAM with KYDAQ.
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Budget - NTR
  - Contracting – authorization to award the Hot Water Recirc contract to Alstom planned for the July IC meeting.
  - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Schedule/Execution – Working towards finalizing a schedule with Voith Hydro that supports all units being completed by the end of 2014. PE is investigating being able to de-water two units simultaneously to gain schedule float.
  - Permitting – NTR
  - Engineering/General:
    - Reviewing Voith updated scope for rehabilitation minus automation.
    - Working with power marketing group on interconnection issues regarding unit testing and commercial dates.
    - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
  - Budget:
    - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope. Revised project sanction planned for July/August IC meeting along with award of remaining runners to Voith through a separate PO while the lump sum contract is negotiated and drafted for a August/September IC meeting.
  - Contracting:
    - Negotiations with Voith ramping up to wrap all existing contracts and purchase orders into a single Lump Sum contract.
  - Issues/Risk
    - Release of third unit runner to Voith is required in August to maintain schedule.
    - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Auditing - NTR
  - Permitting - NTR
  - Engineering/General
    - Meetings continue with station management and URS to move the activities associated with the project from the Plant to PE.
    - Scope development for the limestone building extension is underway with the RFQ being issued to the market within the next few weeks.

        - Working with URS to procure long lead time equipment such as the verti-mill.
    - Budget
        - AIP development in progress.
        - Revised cash flow reflected in 2011 MTP
    - Contracting - NTR
    - Issue/Risk - NTR

- **Cane Run CCP Project**
    - Permitting
        - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
    - Engineering
        - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
        - Transmission working towards relocation of the 69kV line.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
    - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.

- **TC CCP Project – BAP/GSP**
    - Schedule/Execution:
        - Dewatering of the Gypsum Storage Pond was recently completed to allow investigation of existing clay liner thickness and permeability.
    - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
    - Engineering:
        - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
        - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
    - Permitting – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk
        - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from the wet winter and spring.
        - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
    - Schedule/Execution - NTR
    - Budgeting - NTR
    - Engineering – The Detailed Engineering RFP has been issued and bidders are preparing proposals with bids due in early July.
    - Permitting – Negotiations continue with USFWS on the resolution of the Indiana Bat issue. Recent testing on the IN bat was completed with a single finding. Work continues on the development of the 401/404 Permits for an August/September submittal.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
    - Schedule/Execution – NTR
    - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
    - Engineering – Detailed Engineering of gypsum fines and Conceptual Engineering on CCP transport for landfill continues with Black & Veatch. Procurement activities for the gypsum fines project are in progress.
    - Permitting – All permit applications have been made. Project Engineering is working with the various agencies on minimal questions being asked during the review of the permit application. Relocation of the impacted cemetery continues with planning with the local authorities and the cemetery where the remains will be relocated.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk:
        - Land Acquisition – a final offer that will discuss condemnation potential will be sent to the remaining three land owners in early July. A final recommendation will be presented to management for approval on whether to change designs or condemn the remaining property in late July.

- **General CCP Projects**
    - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
    - Safety – NTR
    - Schedule/Execution:
        - Work on Phase I is being suspended until a decision is made on whether to convert the main pond to a landfill. .
        - Aux Pond Phase II work awarded to Charah.
    - Budget – NTR
    - Contract Disputes/Resolution - NTR

  - Issues/Risk – A decision is required in July on whether to continue with the Main Pond or convert to a dry landfill. Economics indicate conversion now to be least cost compared to continuing with pond and then converting once regulations are final.

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - RFP for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI. Pre-bid meetings scheduled at sites July 7 & 8 with bids due July 20 unless extension are granted.
    - RFP addendum being prepared to include bid request for wet systems on all four Ghent units as part of the work on Ghent NOV.
    - MC 4 tests by E.ON Engineering published.
    - MC 3 testing performed for one week with ADA/Breen. Initial results include 8 ppm and 2.3 ppm at the stack; however, significant ESP issues occurred during the test period. ESP issues are being assessed to see if there is a relationship to the testing or if sections tripped due to high hopper levels.
  - Other – Visited IPL Harding Station with Vincent Forcellini and Brad Pabian. They have URS's SBS Injection System on one unit.

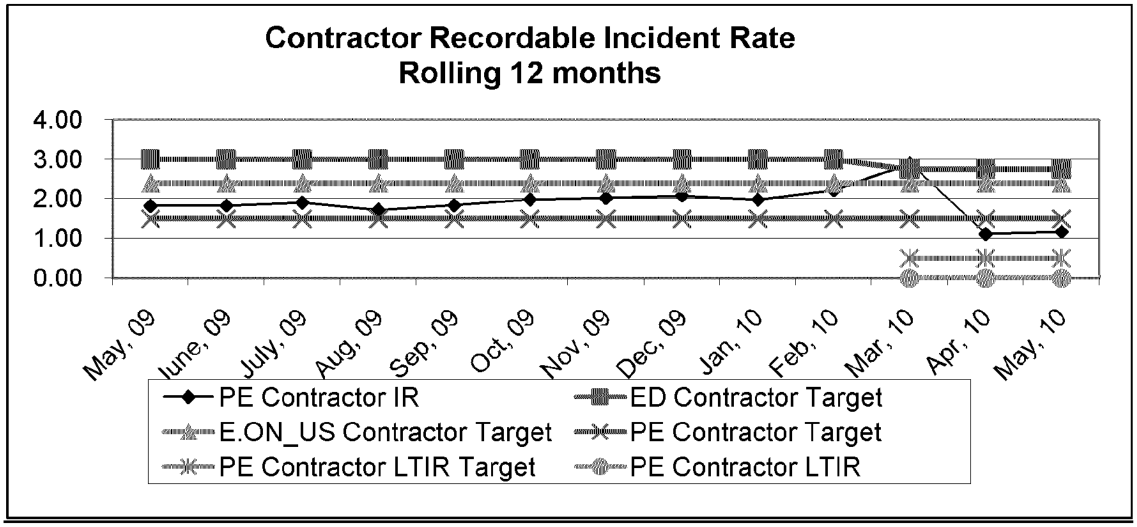
- **SO3 Mitigation (Ghent)**
  - Met with EPA in Atlanta to discuss the NOV issue on June 29 - E.ON technical action items to respond by mid July.
  - GH2 testing postponed until the "permanent" temporary system is installed by the plant.
  - Preparing a test plan and schedule for MgO injection at GH4.
  - Ghent station is currently installing the "permanent" temporary system from Nol-Tek with operation expected around July 9th.
  - B&V draft of SAM testing difficulties white paper received.
  - B&V draft of SAM calculations at Ghent Units received.
  - Emissions Monitoring Inc. (Jim Peeler) has published a white paper on CEMS/Compliance Monitoring Testing.

- **NBU1 and Other Generation Development**
  - LFG
    - Second Landfill Gas Sample Result received.
    - LFG Technologies is planning visits to the landfills in July.
  - NBU CR – HDR updated estimate received. Layout and landfill issues assessed. Gas pipeline issues assessed. Water balance issues assessed. On schedule for late July report draft.
  - Biomass – Black and Veatch submitted draft of Co-Firing Early Estimates and Level I Schedule for MTP purposes. They are progressing with Vista models. On schedule for early August report draft.
  - FutureGen – NTR

- **General**
  - Impoundment Integrity Program – PE is transitioning this to Generation Services.

- Environmental Scenario Planning – The review and refinement of the draft B&V report continues relative to scopes and cost.
- Alstom Master Agreement- Negotiations continue and progressing towards a final agreement in July.

Metrics



Upcoming PWT Needs:

1. Award of the BR3 HWRS to Alstom will need approval in July IC meeting.
2. Decision to convert TC's GSP to a composite liner or maintain current plan. Changing design and implementation now versus later is significantly less expensive and less disruptive to station operations than waiting until after the pond is placed into service. A recommendation from PE and the station will be presented to officers within ES the week after July 4th.
3. Decision to convert Brown's Main Pond to a landfill. Changing direction now before the Main Pond is placed into service is showing to be least cost and least disruptive to station operations. A recommendation from PE and the station will be presented to officers within ES by mid-July.

Staffing

1. Significant staffing increases in PE will be required to manage the current slate of projects in PE's draft 2011 MTP.
2. Philip Imber has submitted for two Manager postings outside of ES.

Energy Services - Bi-Weekly Update
July30, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report (NTR).
  - Auditing – NTR.
  - Schedule/Execution:
    - Ghent
      - Chimney Coatings – Testing of the coating application remain.
      - SCR/FGD Icing Siding – Installation nearing completion.
      - Unit 4 ID Fans – An outage kickoff meeting is planned for 8/4/10.
      - Chimney Capping – Caps placed by helicopter on both chimneys on 7/25/10.
      - Elevators - Award Recommendation is circulating for signatures.
    - Brown
      - The FGD continues to operate very well.
      - E.W. Brown Gypsum Dewatering Facility
        - Product to be sent to the facility next week for final commissioning activity. This was delayed a week due to high ash content in gypsum stream.
        - Facility operation award recommendation being routed for signatures.
      - E.W. Brown Coal Pile Modification
        - Bid received for engineering from MACTEC and PO under development.
      - Balance of Project Items
        - Paving scope out for bid
        - Elevator scope out for bid
  - Budget – Slight reduction in the total Brown FGD Program ITC to $408.8m.
  - Contract Disputes/Resolution - NTR
  - Issues/Risks - NTR

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Bechtel EPC – Bechtel has installed new secondary burner air barrels. The first deliveries of new primary air and core air assemblies have begun to arrive. We continue to work with Bechtel and Fuels to source an alternate coal until the permanent burner solution is installed. **Bechtel anticipates restarting the unit mid-August with a new substantial completion date of 10/12/10.** This impact to commissioning was communicated through a formal letter to KYPSC.
  - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
  - Contract Disputes/Resolution:

        - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Written agreement expected within next two weeks.
    - Issues/Risk:
        - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
    - Schedule/Execution – NTR
    - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
    - Engineering – proceeding as planned to support the spring 2012 in-service.
    - Budget - NTR
    - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
    - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
    - Schedule/Execution –NTR
    - Permitting – NTR
    - Engineering/General:
        - Reviewing Voith updated scope for rehabilitation minus automation.
        - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
    - Budget:
        - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
        - Revised project sanction planned for August IC meeting
    - Contracting:
        - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
    - Issues/Risk
        - Release of third unit runner to Voith is required in August to maintain schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
    - Safety - NTR
    - Auditing - NTR
    - Permitting - NTR
    - Engineering/General
        - Pre-bid meeting for the building extension work was held at Mill Creek on July 8, 2010 and bids were received July 23, 2010.
        - Working with URS to develop RFQ for long lead equipment.
    - Budget
        - AIP complete.
        - Revised cash flow reflected in 2011 MTP

  - Contracting – NTR
  - Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
    - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
    - Work has begun on both Emergency Spillways.
    - Working continues on the fiberglass piping for the project
  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a composite liner system to meet proposed new regulations before the pond is placed into service.
    - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
  - Permitting – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk

    - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
    - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
  - Schedule/Execution - NTR
  - Budgeting - NTR
  - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
  - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
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  - Study by PE and GAI has been completed in final draft form that identifies very conceptual cost to comply with EPA options of CCP storage. Range of cost is $700 - $1,100 million and is dependent on Subpart C or Subpart D final ruling. These costs do not include potential additional landfill cost at Mill Creek, Green River, or conversion of Brown ATB to Landfill. These cost have been included in PE's 2011 MTP draft.

- **E.W. Brown Ash Pond Project**
  - Safety – NTR
  - Schedule/Execution:
    - Work on Phase I is being suspended until a decision is made on whether to convert the main pond to a landfill.
    - Working on evaluation and recommendation paper for the main pond conversion from a pond to a landfill .
    - Aux Pond Phase II work awarded to Charah.
  - Budget – NTR
  - Contract Disputes/Resolution - NTR
  - Issues/Risk – A decision is required in July on whether to continue with the Main Pond or convert to a dry landfill. Economics indicate conversion now to be least cost compared to continuing with pond and then converting once regulations are final.

- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension except for rock embankment placement, dust control, and general site maintenance.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
      - Rock placement continued on the West and South Embankments.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Installation of erosion and sediment control measures.
      - Topsoil stockpiles were relocated.
      - Began rock embankment blasting at the Houp Property.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution:
    - Proposals for MC3, MC4, BR3 and GH2 released June 29 to URS, Nol-Tek, UCC, FLsmidth, ClydeBergemann, and BCSI received July 20.
    - Bid review meetings held with stations and all suppliers July 26 & 28.
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    - B&V reworking SAM calculations for the Ghent Units based on Title V Heat Inputs..
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        - BACT based on 2005 RBLC database for emissions limits
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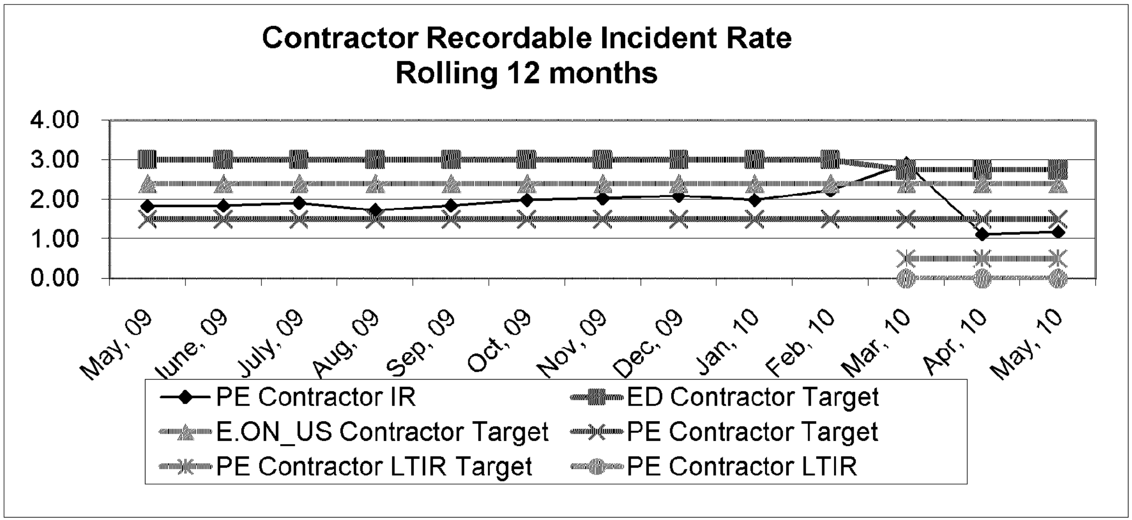
Metrics



Upcoming PWT Needs:

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2. Philip Imber has submitted for two postings outside of ES.
3. Jason Finn has submitted for positions.
4. Charlie Jacobs, Lana Linkenhoker, Charlie White and Bill Moerhke out due to surgery/illness.

From: Gregory, Ronald
To: Saunders, Eileen
Sent: 8/11/2010 7:04:46 PM
Subject: PE's Bi-Weekly Update of 8-13-10
Attachments: PE's Bi-Weekly Update of 8-13-10 rdg.docx

Since you don't have anything else to do.

<<...>>

Energy Services - Bi-Weekly Update
August 13, 2010
PROJECT ENGINEERING

- **KU SOx**
    - Safety – Nothing new to report (NTR).
    - Auditing – NTR.
    - Schedule/Execution:
        - Ghent
            - Chimney Coatings – Testing of the coating application remain.
            - SCR/FGD Icing Siding – Installation nearing completion.
            - Unit 4 ID Fans – An outage kickoff meeting is planned for 8/4/10.
            - Chimney Capping – Caps placed by helicopter on both chimneys on 7/25/10.
            - Elevators - Award Recommendation is circulating for signatures.
        - Brown
            - FGD, Limestone and BOP
                - Fluor continues to work on punchlist items and perform demobilization activities.
                - Major activities will resume just prior to the scheduled fall outage for Brown Unit 1.
            - E.W. Brown Gypsum Dewatering Facility
                - Gypsum slurry sent to facility on 8/5, with minor checkout issues on-going.
                - Facility operational contract awarded to FPG. Contractor labor began training on equipment.
            - E.W. Brown Coal Pile Modification
                - MACTEC awarded engineering contract.
                - Soil borings and bathymetric survey conducted.
                - Engineering design on-going.
            - Balance of Project Items
                - Paving scope bids received and an award recommendation is being prepared.
                - Elevator scope bids received and an award recommendation is being prepared.
    - Budget – NTR.
    - Contract Disputes/Resolution - NTR
    - Issues/Risks - NTR

- **TC2**
    - Safety – NTR
    - Permitting – NTR
    - Auditing – NTR
    - Schedule/Execution:
        - Bechtel EPC – Bechtel has installed new secondary burner air barrels. The first deliveries of new primary air and core air assemblies have begun to arrive. We continue to work with Bechtel and Fuels to source an alternate coal until the permanent burner solution is installed. **Bechtel anticipates**

        restarting the unit mid-August with a new substantial completion date of 10/12/10. This impact to commissioning was communicated through a formal letter to KYPSC.
    - Budget – Minor additions made to MTP to account for staffing through 2011 and for the recently verbal agreement on FM and EE claim settlement.
    - Contract Disputes/Resolution:
        - Bechtel FM Claims – Verbal agreement on all FM and most EE claims reached. Written agreement expected within next two weeks.
    - Issues/Risk:
        - Delivery of the new burners, design of the DBEL burners for our coal specification, remaining commissioning beyond the 50% load achieved to date.

- **Brown 3 SCR**
    - Schedule/Execution – NTR
    - Permitting – Request to KYDAQ for station-wide SAM annual emission limit sent to KYDAQ on 7/30/10. Permit to construct SCR dependent on agreement with KYDAQ on SAM limit.
    - Engineering – proceeding as planned to support the spring 2012 in-service.
    - Budget - NTR
    - Contracting – IC approved award of Hot Water Recirc to Alstom in the July IC meeting.
    - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
    - Schedule/Execution –NTR
    - Permitting – NTR
    - Engineering/General:
        - Reviewing Voith updated scope for rehabilitation minus automation.
        - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
    - Budget:
        - Total roll up of estimate to complete work under a lump sum to Voith Hydro is essentially at 2010 MTP values. PE continues to assemble pricing for work outside hydro vendor scope.
        - Revised project sanction planned for August IC meeting
    - Contracting:
        - Negotiations with Voith are progressing well. Voith has agreed to defer the need to issue a PO for the remaining runners pending approval of EPC from IC in August.
    - Issues/Risk
        - Release of third unit runner to Voith is required in August to maintain schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Mill Creek Limestone Project**
    - Safety - NTR
    - Auditing - NTR
    - Permitting - NTR
    - Engineering/General

    - Pre-bid meeting for the building extension work was held at Mill Creek on July 8, 2010 and bids were received July 23, 2010.
    - Working with URS to develop RFQ for long lead equipment.
  - Budget
    - AIP complete.
    - Revised cash flow reflected in 2011 MTP
  - Contracting – NTR
  - Issue/Risk – Potential delay in awarding the equipment and engineering for the verti-mills as the impacts of the new air regulations are being assessed.

- **Cane Run CCP Project**
  - Permitting
    - 404/401 and Landfill Permit applications remain under review by the agencies. Preparing to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone well.
  - Engineering
    - Finalization of construction drawings are on hold until the KYDWM has completed their initial review.
    - Meeting with the Plant and the engineer to discuss a reduced scope landfill that would facilitate the construction of a CCGT.
    - Transmission working towards relocation of the 69kV line.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
  - PE notified to re-start engineering and procurement activities due to negotiations with Holcim being resumed.
  - Working with UCC to update their equipment and material pricing.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Gypsum Storage Pond is being prepared for the installation of the Flexible Membrane Liner (FML) and a Geosynthetic Clay Liner (GCL) scheduled to begin within the next 2 to 4 weeks.
    - Work continues on the fill placement and mechanically stabilized earth (MSE) wall for the north, south, and west dikes.
    - Work has begun on both Emergency Spillways.
    - Working continues on the fiberglass piping for the project
  - Budgeting – The additional $1.5m net against a project sanction of $25m net to fund modifying the GSP liner system to meet anticipated future regulations will require IC approval and a revised AIP.
  - Engineering:
    - Performing a study on the GSP clay liner originally installed to compare against potential new regulations. Path forward is to utilize the existing clay liner as part of a

        composite liner system to meet proposed new regulations before the pond is placed into service.
        - A repair strategy for the BAP is being developed in response to the EPA Inspection in June 2009.
    - Permitting – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk
        - Weather remains the biggest risk. The contractor has submitted a request for adjustments to the LDs due to the weather delays from 2009 and the wet winter and spring in 2010.
        - PE is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
    - Schedule/Execution - NTR
    - Budgeting - NTR
    - Engineering – The Detailed Engineering RFPs were received on Friday, 09Jul10. Three proposals were received. Proposal review is in progress.
    - Permitting – A meeting was held with USFWS on 27Jul10 concerning the resolution of the Indiana Bat issue. Anabat (acoustical) Testing on the Phase II (July) for the Indiana Bat is being concluded during the week of 26Jul10. Only two "hits" were recorded. Work continues on the development of the 401/404 Permits for Fall 2010 submittal.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
    - Schedule/Execution – NTR
    - Budget – Conceptual Engineering on the CCP transport systems has resulted in a refined estimate that is significantly over the original amount included in the project ECR filings. PE will continue working with B&V and station management through the 2011 MTP development to refine the scope and reduce the cost impact.
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- **E.W. Brown Ash Pond Project**
  - **E.W. Brown Starter Dike**
    - Safety – (0) Recordable
    - Schedule/Execution:
      - Contract work remains under suspension. Summit demobilized 90% of equipment and performed requested gradework and site stabilization activity.
      - 95% of exposed ash has been covered with either straw mats or filter fabric as dust control.
    - Budget – NTR
    - Contract Disputes/Resolution: NTR
    - Issues/Risk – Summit was given notice to suspend all work except rock placement and some minor activities beginning July 6th until further notice.

  - **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
      - Continued rock embankment blasting at the Houp Property.
      - Began rock embankment placement on the East side foundation.
    - Budget – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

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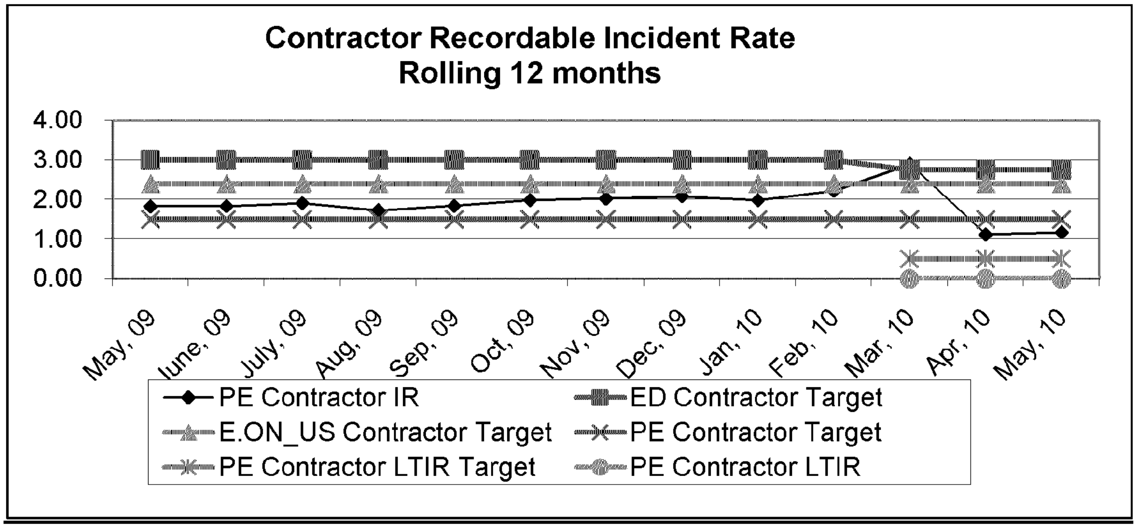

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From:	Cosby, David
To:	Saunders, Eileen
Sent:	8/12/2010 12:22:06 AM
Subject:	RE: 167987.26.0000 100617 - EON Draft AQC Technology Cost Report
Attachments:	Environmental Summay (rev5 6-3-10).xlsx

Hey Eileen. I hope all is well with you and your family. Summer is almost over for the kids. Time flies.

Are there any updates to the ongoing O&M costs estimated from the short file and long file that were sent out in late June? We are still using the $191M per year (with Cane Run and Green River taken out of the overall $260M total). I have not heard if the proposed reduction on Mill Creek scope is "official" or not and if that impacts this original O&M estimate breakdown. I know the timing on some things will change and I am using Rusty's block diagram for that.

Please advise when you get a chance. Thanks.

David L. Cosby Jr.
Manager - Fin. & Budgeting - Power Production
EON US / LG&E / KU
502-627-2499
david.cosby@eon-us.com

From: Saunders, Eileen
Sent: Monday, June 21, 2010 11:30 AM
To: Voyles, John; Bowling, Ralph; Crutcher, Tom; Turner, Haley; Fraley, Jeffrey; Pabian, Brad; Carman, Barry; Joyce, Jeff; Nix, Stephen; Piening, Carla; Kirkland, Mike; Koller, Tiffany; Stevens, Michael; Troost, Tom; Harper, Travis; Turner, Steven; Hensley, Mike; Wilson, Stuart; Karavayev, Louanne; Cosby, David; Hudson, Rusty; Raque, Gary; Revlett, Gary; Black, Greg; Imber, Philip
Cc: Straight, Scott
Subject: FW: 167987.26.0000 100617 - EON Draft AQC Technology Cost Report

All,

Enclosed, please find the draft report from B&V. Scott and I have just begun the review but I wanted to share the document with you as well. As discussed previously, this information does not meet the criteria for Level 1 Engineering, but it is a starting point for further analysis. If you have any comments, please send them to me by Friday, June 25, 2010.

Before you print this document, I want to warn you that it is roughly 400 pages.

Thanks,

Eileen

From: Lucas, Kyle J. [mailto:LucasKJ@bv.com]
Sent: Thursday, June 17, 2010 10:20 PM
To: Saunders, Eileen
Cc: Hillman, Timothy M.; Mahabaleshwarkar, Anand; Lawson, Stacy J.
Subject: 167987.26.0000 100617 - EON Draft AQC Technology Cost Report

Eileen,
Attached, please find the draft air quality control Technology Cost Report. Please review the document and provide one set of consolidated written comments by COB Thursday June 24, 2010. B&V will review the consolidated comments and incorporate, as appropriate, into the final report.

Additionally, Please confirm receipt of this document.

Regards,
Kyle

Kyle Lucas | Environmental Permitting Manager
Black & Veatch - Building a World of Difference™
11401 Lamar Avenue
Overland Park, KS 66211
Phone: **(913) 458-9062** | Fax: **(913) 458-9062**
Email: **lucaskj@bv.com**

	A	B	C	D	E	F	G	H
1	Black & Veatch Study Cost Estimates							
2	$ in thousands							
3								
4								
5			**Capital Cost**		**O&M Cost**		**Levelized Annual Costs**	
6	**BROWN**							
7	Brown 1 - Low NOx Burners		$1,156		$0		$141	
8	Brown 1 - Baghouse		$40,000		$1,477		$6,345	
9	Brown 1 - PAC Injection		$1,599		$614		$809	
10	Brown 1 - Neural Networks		$500		$50		$111	
11	Brown 1 - Overfire Air		$767		$132		$225	
12	Total Brown 1		**$44,022**		**$2,273**		**$7,631**	
13								
14	Brown 2 - SCR		$92,000		$3,278		$14,474	
15	Brown 2 - Baghouse		$51,000		$1,959		$8,166	
16	Brown 2 - PAC Injection		$2,476		$1,090		$1,391	
17	Brown 2 - Neural Networks		$500		$50		$111	
18	Brown 2 - Lime Injection		$2,739		$1,155		$1,488	
19	Total Brown 2		**$148,715**		**$7,532**		**$25,630**	
20								
21	Brown 3 - Baghouse		$61,000		$3,321		$10,745	
22	Brown 3 - PAC Injection		$5,426		$2,330		$2,990	
23	Brown 3 - Neural Networks		$1,000		$100		$222	
24	Total Brown 3		**$67,426**		**$5,751**		**$13,957**	
25								
26	**Total Brown**		**$260,163**		**$15,556**		**$47,218**	
27								
28								
29	**GHENT**							
30	Ghent 1 - Baghouse		$131,000		$5,888		$21,831	
31	Ghent 1 - PAC Injection		$6,380		$4,208		$4,984	
32	Ghent 1 - Neural Networks		$1,000		$100		$222	
33	Total Ghent 1		**$138,380**		**$10,196**		**$27,037**	
34								
35	Ghent 2 - SCR		$227,000		$7,078		$34,704	
36	Ghent 2 - Baghouse		$120,000		$5,002		$19,606	
37	Ghent 2 - PAC Injection		$6,109		$2,880		$3,623	
38	Ghent 2 - Lime Injection		$5,483		$2,775		$3,442	
39	Ghent 2 - Neural Networks		$1,000		$100		$222	
40	Total Ghent 2		**$359,592**		**$17,835**		**$61,597**	
41								
42	Ghent 3 - Baghouse		$138,000		$6,122		$22,917	
43	Ghent 3 - PAC Injection		$6,173		$4,134		$4,885	
44	Ghent 3 - Neural Networks		$1,000		$100		$222	
45	Total Ghent 3		**$145,173**		**$10,356**		**$28,024**	
46								

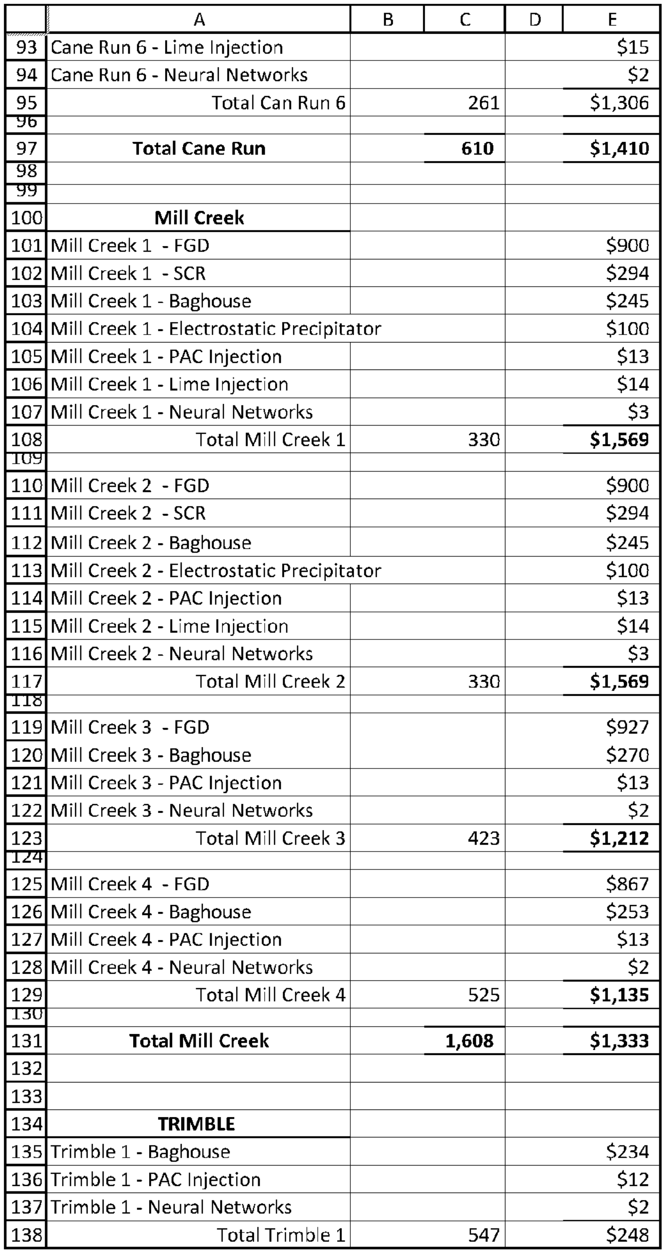
	A	B	C	D	E	F	G	H
47	Ghent 4 - Baghouse		$117,000		$5,363		$19,602	
48	Ghent 4 - PAC Injection		$6,210		$3,896		$4,652	
49	Ghent 4 - Neural Networks		$1,000		$100		$222	
50	Total Ghent 4		$124,210		$9,359		$24,476	
51								
52	**Total Ghent**		**$767,355**		**$47,746**		**$141,134**	
53								
54								
55	**GREEN RIVER**							
56	Green River 3 - SCR		$29,000		$1,040		$4,569	
57	Green River 3 - CDS-FF		$38,000		$6,874		$11,499	
58	Green River 3 - PAC Injection		$1,112		$323		$458	
59	Green River 3 - Neural Networks		$500		$50		$111	
60	Total Green River 3		**$68,612**		**$8,287**		**$16,637**	
61								
62	Green River 4 - SCR		$42,000		$1,442		$6,553	
63	Green River 4 - CDS-FF		$54,000		$10,289		$16,861	
64	Green River 4 - PAC Injection		$1,583		$515		$708	
65	Green River 4 - Neural Networks		$500		$50		$111	
66	Total Green River 4		**$98,083**		**$12,296**		**$24,233**	
67								
68	**Total Green River**		**$166,695**		**$20,583**		**$40,870**	
69								
70								
71	**CANE RUN**							
72	Cane Run 4 - FGD		$152,000		$8,428		$26,926	
73	Cane Run 4 - SCR		$63,000		$2,219		$9,886	
74	Cane Run 4 - Baghouse		$33,000		$1,924		$5,940	
75	Cane Run 4 - PAC Injection		$2,326		$1,087		$1,370	
76	Cane Run 4 - Lime Injection		$2,569		$983		$1,296	
77	Cane Run 4 - Neural Networks		$500		$50		$111	
78	Total Cane Run 4		**$253,395**		**$14,691**		**$45,529**	
79								
80	Cane Run 5 - FGD		$159,000		$8,789		$28,139	
81	Cane Run 5 - SCR		$66,000		$2,421		$10,453	
82	Cane Run 5 - Baghouse		$35,000		$2,061		$6,321	
83	Cane Run 5 - PAC Injection		$2,490		$1,120		$1,423	
84	Cane Run 5 - Lime Injection		$2,752		$1,089		$1,424	
85	Cane Run 5 - Neural Networks		$500		$50		$111	
86	Total Cane Run 5		**$265,742**		**$15,530**		**$47,871**	
87								
88	Cane Run 6 - FGD		$202,000		$10,431		$35,014	
89	Cane Run 6 - SCR		$86,000		$2,793		$13,259	
90	Can Rune 6 - Baghouse		$45,000		$2,672		$8,149	
91	Cane Run 6 - PAC Injection		$3,490		$1,336		$1,761	
92	Cane Run 6 - Lime Injection		$3,873		$1,367		$1,838	

	A	B	C	D	E	F	G	H
93	Cane Run 6 - Neural Networks		$500		$50		$111	
94	Total Can Run 6		$340,863		$18,649		$60,132	
95								
96	**Total Cane Run**		**$860,000**		**$48,870**		**$153,532**	
97								
98								
99	**Mill Creek**							
100	Mill Creek 1 - FGD		$297,000		$14,341		$50,486	
101	Mill Creek 1 - SCR		$97,000		$3,366		$15,171	
102	Mill Creek 1 - Baghouse		$81,000		$3,477		$13,335	
103	Mill Creek 1 - Electrostatic Precipitator		$32,882		$3,581		$7,583	
104	Mill Creek 1 - PAC Injection		$4,412		$2,213		$2,750	
105	Mill Creek 1 - Lime Injection		$4,480		$2,024		$2,569	
106	Mill Creek 1 - Neural Networks		$1,000		$100		$222	
107	Total Mill Creek 1		**$517,774**		**$29,102**		**$92,116**	
108								
109	Mill Creek 2 - FGD		$297,000		$14,604		$50,749	
110	Mill Creek 2 - SCR		$97,000		$3,401		$15,206	
111	Mill Creek 2 - Baghouse		$81,000		$3,518		$13,376	
112	Mill Creek 2 - Electrostatic Precipitator		$32,882		$3,664		$7,666	
113	Mill Creek 2 - PAC Injection		$4,412		$2,340		$2,877	
114	Mill Creek 2 - Lime Injection		$4,480		$2,117		$2,662	
115	Mill Creek 2 - Neural Networks		$1,000		$100		$222	
116	Total Mill Creek 2		**$517,774**		**$29,744**		**$92,758**	
117								
118	Mill Creek 3 - FGD		$392,000		$18,911		$66,617	
119	Mill Creek 3 - Baghouse		$114,000		$4,923		$18,797	
120	Mill Creek 3 - PAC Injection		$5,592		$3,213		$3,894	
121	Mill Creek 3 - Neural Networks		$1,000		$100		$222	
122	Total Mill Creek 3		**$512,592**		**$27,147**		**$89,530**	
123								
124	Mill Creek 4 - FGD		$455,000		$21,775		$77,149	
125	Mill Creek 4 - Baghouse		$133,000		$5,804		$21,990	
126	Mill Creek 4 - PAC Injection		$6,890		$3,858		$4,697	
127	Mill Creek 4 - Neural Networks		$1,000		$100		$222	
128	Total Mill Creek 4		**$595,890**		**$31,537**		**$104,058**	
129								
130	**Total Mill Creek**		**$2,144,030**		**$117,530**		**$378,462**	
131								
132								
133	**TRIMBLE**							
134	Trimble 1 - Baghouse		$128,000		$5,782		$21,360	
135	Trimble 1 - PAC Injection		$6,451		$4,413		$5,198	
136	Trimble 1 - Neural Networks		$1,000		$100		$222	
137	Total Trimble 1		$135,451		$10,295		$26,780	
138								

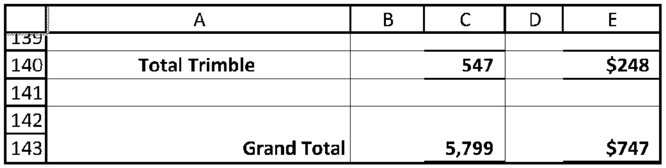
	A	B	C	D	E	F	G	H
139	**Total Trimble**		**$135,451**		**$10,295**		**$26,780**	
140								
141								
142	**Grand Total**		**$4,333,694**		**$260,580**		**$787,996**	

	A	B	C	D	E
1	Black & Veatch Study Cost Estimates				
2					
3					
4					
5			**MW**		**$/kW**
6	**BROWN**				
7	Brown 1 - Low NOx Burners				$11
8	Brown 1 - Baghouse				$364
9	Brown 1 - PAC Injection				$15
10	Brown 1 - Neural Networks				$5
11	Brown 1 - Overfire Air				$7
12	Total Brown 1		110		**$400**
13					
14	Brown 2 - SCR				$511
15	Brown 2 - Baghouse				$283
16	Brown 2 - PAC Injection				$14
17	Brown 2 - Neural Networks				$3
18	Brown 2 - Lime Injection				$15
19	Total Brown 2		180		**$826**
20					
21	Brown 3 - Baghouse				$133
22	Brown 3 - PAC Injection				$12
23	Brown 3 - Neural Networks				$2
24	Total Brown 3		457		**$148**
25					
26	**Total Brown**		**747**		**$348**
27					
28					
29	**GHENT**				
30	Ghent 1 - Baghouse				$242
31	Ghent 1 - PAC Injection				$12
32	Ghent 1 - Neural Networks				$2
33	Total Ghent 1		541		**$256**
34					
35	Ghent 2 - SCR				$439
36	Ghent 2 - Baghouse				$232
37	Ghent 2 - PAC Injection				$12
38	Ghent 2 - Lime Injection				$11
39	Ghent 2 - Neural Networks				$2
40	Total Ghent 2		517		**$696**
41					
42	Ghent 3 - Baghouse				$264
43	Ghent 3 - PAC Injection				$12
44	Ghent 3 - Neural Networks				$2
45	Total Ghent 3		523		**$278**
46					

	A	B	C	D	E
47	Ghent 4 - Baghouse				$222
48	Ghent 4 - PAC Injection				$12
49	Ghent 4 - Neural Networks				$2
50	Total Ghent 4		526		$236
51					
52	**Total Ghent**		**2,107**		**$364**
53					
54					
55					
56	**GREEN RIVER**				
57	Green River 3 - SCR				$408
58	Green River 3 - CDS-FF				$535
59	Green River 3 - PAC Injection				$16
60	Green River 3 - Neural Networks				$7
61	Total Green River 3		71		**$966**
62					
63	Green River 4 - SCR				$385
64	Green River 4 - CDS-FF				$495
65	Green River 4 - PAC Injection				$15
66	Green River 4 - Neural Networks				$5
67	Total Green River 4		109		**$900**
68					
69	**Total Green River**		**180**		**$926**
70					
71					
72	**CANE RUN**				
73	Cane Run 4 - FGD				$905
74	Cane Run 4 - SCR				$375
75	Cane Run 4 - Baghouse				$196
76	Cane Run 4 - PAC Injection				$14
77	Cane Run 4 - Lime Injection				$15
78	Cane Run 4 - Neural Networks				$3
79	Total Cane Run 4		168		**$1,508**
80					
81	Cane Run 5 - FGD				$878
82	Cane Run 5 - SCR				$365
83	Cane Run 5 - Baghouse				$193
84	Cane Run 5 - PAC Injection				$14
85	Cane Run 5 - Lime Injection				$15
86	Cane Run 5 - Neural Networks				$3
87	Total Cane Run 5		181		**$1,468**
88					
89	Cane Run 6 - FGD				$774
90	Cane Run 6 - SCR				$330
91	Can Rune 6 - Baghouse				$172
92	Cane Run 6 - PAC Injection				$13



	A	B	C	D	E
93	Cane Run 6 - Lime Injection				$15
94	Cane Run 6 - Neural Networks				$2
95	Total Can Run 6		261		$1,306
96					
97	**Total Cane Run**		**610**		**$1,410**
98					
99					
100	**Mill Creek**				
101	Mill Creek 1 - FGD				$900
102	Mill Creek 1 - SCR				$294
103	Mill Creek 1 - Baghouse				$245
104	Mill Creek 1 - Electrostatic Precipitator				$100
105	Mill Creek 1 - PAC Injection				$13
106	Mill Creek 1 - Lime Injection				$14
107	Mill Creek 1 - Neural Networks				$3
108	Total Mill Creek 1		330		**$1,569**
109					
110	Mill Creek 2 - FGD				$900
111	Mill Creek 2 - SCR				$294
112	Mill Creek 2 - Baghouse				$245
113	Mill Creek 2 - Electrostatic Precipitator				$100
114	Mill Creek 2 - PAC Injection				$13
115	Mill Creek 2 - Lime Injection				$14
116	Mill Creek 2 - Neural Networks				$3
117	Total Mill Creek 2		330		**$1,569**
118					
119	Mill Creek 3 - FGD				$927
120	Mill Creek 3 - Baghouse				$270
121	Mill Creek 3 - PAC Injection				$13
122	Mill Creek 3 - Neural Networks				$2
123	Total Mill Creek 3		423		**$1,212**
124					
125	Mill Creek 4 - FGD				$867
126	Mill Creek 4 - Baghouse				$253
127	Mill Creek 4 - PAC Injection				$13
128	Mill Creek 4 - Neural Networks				$2
129	Total Mill Creek 4		525		**$1,135**
130					
131	**Total Mill Creek**		**1,608**		**$1,333**
132					
133					
134	**TRIMBLE**				
135	Trimble 1 - Baghouse				$234
136	Trimble 1 - PAC Injection				$12
137	Trimble 1 - Neural Networks				$2
138	Total Trimble 1		547		$248



	A	B	C	D	E
139					
140	**Total Trimble**		**547**		**$248**
141					
142					
143	**Grand Total**		**5,799**		**$747**

From:	Schram, Chuck
To:	Bellar, Lonnie
CC:	Conroy, Robert; Sinclair, David; Wilson, Stuart
Sent:	7/27/2010 5:24:19 PM
Subject:	RE: B&V Report
Attachments:	COMPLETE Draft EON AQC Cost Study 061710.pdf

Lonnie,
Attached is a June version of the B&V report. Project Eng gave us a link to a newer version, but it's stored on a remote site which is not currently responding. We'll try to get a final PDF copy.

Chuck

From: Bellar, Lonnie
Sent: Tuesday, July 27, 2010 3:44 PM
To: Schram, Chuck
Cc: Conroy, Robert
Subject: B&V Report

Chuck,

Would it be possible for Robert and I to get an (electronic is fine) copy of the B&V report before the meeting tomorrow?

Lonnie

E.ON US
Coal Fired Fleet Wide

Air Quality Control
Technology Cost Assessment

B&V Project: 167987
B&V File No.: 26.0000

Issue Date and Revision
June 2010
Rev. B

BLACK & VEATCH
Building a world of difference.

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Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Summary of Plant AQC Technology Costs

Acronym List

AQC	Air Quality Control
BOP	Balance-of-Plant
CAIR	Clean Air Interstate Rule
CDS	Circulating Dry Scrubber
CO	Carbon Monoxide
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
Hg	Mercury
ID	Induced Draft
LNB	Low NO_x Burners
MACT	Maximum Achievable Control Technology
MBtu	Million British Thermal Unit
NN	Neural Network
NO_x	Nitrogen Oxides
O&M	Operation and Maintenance
OFA	Overfire Air
PAC	Powdered Activated Carbon
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide

Executive Summary

The purpose of this study was to develop fleet-wide, high-level, capital and O&M costs for recommend air quality control equipment necessary to meet future environmental requirements at 18 coal-fired units located at 6 facilities (E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River) owned and operated by E.ON. The study was conducted at a high-level and under a tight schedule in order to meet E.ON's requirements.

To perform the study, Black &Veatch dispatched two teams of engineers to conduct site visits and walk-downs at each of the 6 facilities over the course of 3 days. Based on information gathered during these site visits, initial air quality control equipment recommendations were prepared for E.ON's review and approval before proceeding with the cost estimate. Following E.ON's approval, high-level capital and O&M costs were determined for each unit and air quality control technology. Table ES-1 summarizes the capital and O&M cost totals rolled up for each facility.

Table ES-1
Summary of Plant AQC Technology Costs

Plant	Capital Cost ($/1,000)	Operating Cost ($/kW)	O&M Cost ($/1,000)	Levelized Annual Cost ($/1,000)
E.W. Brown	260,163	1,374	15,556	47,218
Ghent	767,355	1,465	47,746	141,134
Cane Run	860,000	4,282	48,870	153,532
Mill Creek	2,144,030	5,485	117,530	378,462
Trimble County	135,451	248	10,295	26,780
Green River	166,695	1,866	20,583	40,870
Total	4,333,694	14,720	260,580	787,996

This report contains a breakdown of the aforementioned costs and summarizes the basis and supporting documentation used to develop them. The supporting documentation includes site visit notes, control technology recommendations, design basis, process flow diagrams, equipment layout drawings, and milestone implementation schedules for the selected technologies.

1.0 Introduction

Black & Veatch was tasked by E.ON to provide a high-level cost estimate of air quality compliance expenditures necessary to meet expected future regulatory requirements for budgetary purposes. The following coal fired units were considered in this study:

- E.W. Brown – Units 1, 2, and 3.
- Ghent – Units 1, 2, 3, and 4.
- Cane Run – Units 4, 5, and 6.
- Mill Creek – Units 1, 2, 3, and 4.
- Trimble County – Units 1 and 2.[1]
- Green River – Units 3 and 4.

To accomplish this objective, Black & Veatch personnel collected the necessary unit-specific data and performed onsite observations to prepare this AQC retrofit technology and cost assessment. Based on information gathered during these site visits, initial air quality control equipment recommendations were prepared for E.ON's review and approval before proceeding with the cost estimate. To support this process, design basis, process flow diagrams, equipment layout drawings, and milestone implementation schedules for the selected technologies were developed.

Based on B&V experience, technical and economic assumptions were made in order to facilitate rapid development of the technical calculations and costs estimates. Of special note, the capital cost estimates and annual operating cost data for the AQC equipment should be considered as high-level conceptual design estimates and should be confirmed with a more detailed follow-up assessment before initiating an implementation plan.

The assessment identifies AQC technologies for reducing unit-specific air emissions for pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), carbon monoxide (CO), mercury (Hg), hydrogen chloride (HCl), and dioxin/furans. This report documents the assumptions and findings of the assessment, including the identification of retrofit AQC technologies to achieve compliance at each unit, as well as order-of-magnitude costs capital and operation and maintenance (O&M) cost estimates, process flow diagrams, summary plot plan drawings, and Level 1

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[1] Unit 2 at Trimble County is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Therefore, this unit was excluded from further analyses.

summary schedules to engineer, procure, and install each recommended technology. Additionally, the report identifies potential impacts the AQC technologies may impose on balance-of-plant (BOP) systems as applicable, such as, electric systems, ash handling systems, water supply and wastewater treatment systems.

2.0 Pollutant Emission Targets

The potential impact of future regulations are the primary driver for both the timing and nature of environmental controls planned at the E.ON plants. Among the regulatory drivers are the Utility Maximum Achievable Control Technology (MACT) and the Transport Rule -- Clean Air Interstate Rule (CAIR) replacement to be proposed by the United States Environmental Protection Agency (USEPA) by March 2011 and summer 2010, respectively. These two regulatory drivers and their associated emission levels serve as the primary basis used by Black & Veatch to develop unit-by-unit AQC technology recommendations.

E.ON provided a matrix of estimated requirements under future new environmental regulations, as well as a summary implementation schedule of regulatory programs. This information is provided in Appendix A. From this information, E.ON developed specific pollutant emission limit targets with the intent that the limits would be applied to each unit individually to assess current compliance and the potential for additional AQC equipment. For the purposes of this study, compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) were not considered. Table 2-1 summarizes the future pollution emission targets provided by E.ON for each unit.

Table 2-1
Future Pollution Emission Targets

Pollutant	Future Pollutant Emission Limit (lb/MBtu)
NO_x	0.11
SO_2	0.25
PM	0.03
CO	0.10(a)
Hg	0.000001(b)
HCl	0.002
Dioxin/Furan	15×10^{-18}

(a) E.ON's original emission matrix provided a CO emission level of 0.02 lb/MBtu. It was determined that there was not a feasible and proven control technology available for the type and size of unit being assessed. Therefore, on May 21, 2010, the future pollutant emission limit was modified to reflect 0.10 lb/MBtu, which is considered reflective of potentially achievable CO emissions from coal fired units.

(b) The emission matrix indicated 0.012 lb/GWh or 90 percent reduction.

3.0 Study Basis and Methodology

The following sections discuss the basis and methodology used to make the AQC technology recommendations and cost estimates presented herein. These activities included site visits, development of a design basis, costs estimate methodology development, and economic assumptions.

3.1 Site Visits

During the week of May 10, 2010, E.ON provided Black & Veatch personnel access to each plant site to review existing unit systems and components and discuss current operational issues with appropriate plant personnel. The discussions focused on plant-specific issues that could potentially impact the selection, installation, and operation of future AQC technologies, such as:

- Available space to locate new AQC equipment.
- Availability of auxiliary power.
- Condition assessment of major equipment.
- Identification of BOP issues.
- Constructability issues.

These discussions were followed by plant lead facility tours. Each plant site visit ended with an exit meeting, where the initial recommendations and findings were summarized with the plant team. A brief description of site visit observations and AQC considerations for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble, and Green River are included in Sections 4.1.1, 4.2.1, 4.3.1, 4.4.1, 4.5.1, and 4.6.1, respectively. Table 3-1 identifies team personnel and facilities visited by each Black & Veatch team.

Table 3-1
Black & Veatch Team Members

Team No. 1[(a)]	
Black & Veatch Team Member	**Position**
Anand Mahabaleshwarkar	Air Quality Control Engineer
Richard Hooper	Mechanical Engineer
Mike Ballard	Civil/Structural Engineer
Team No. 2[(b)]	
Black & Veatch Team Member	**Position**
Pratik Mehta	Air Quality Control Engineer
Dave Muggli	Mechanical Engineer
Roger Goodlet	Civil/Structural Engineer

(a)Visited Cane Run, Mill Creek, and Green River Stations on May 11, May 12, and May 13, respectively.
(b)Visited Ghent, Trimble County, and E.W. Brown Stations on May 11, May 12, and May 13, respectively.

3.2 Design Basis

A design basis was established for each unit based on information provided by E.ON (included in Appendix B) and results from Black & Veatch's internal combustion calculations. Information in the design basis was used as the basis for estimating equipment sizes, performance calculations, cost estimates (capital, operating, and maintenance) and also for estimating resource consumption, auxiliary power requirements, and byproduct disposal volumes. The performance calculations developed were based on the established design basis parameters and served as the basis for estimating capital and annual O&M costs for proven and feasible AQC equipment. The design basis is provided in Appendix C.

3.3 Cost Methodology

Capital and annual O&M costs to procure, install, and operate the E.ON approved AQC technologies were developed for each of 17 units[2]. All cost information was produced for unit-specific combinations of new AQC technology components —

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[2] Unit 2 at Trimble County is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Therefore, this unit was excluded from further analyses.

upgrades to existing AQC equipment were not considered. A brief description of the proven and feasible AQC technologies considered for this study is included in Appendix D.

To support the cost estimate, Black & Veatch performed a high-level fatal flaw analysis of the following for each selected emission control technology for each unit:

- Flue Gas Conditions. Based on design fuel analysis, boiler steaming capacity, and current operating characteristics, Black & Veatch determined the flue gas conditions to be used as the basis for the AQC equipment design basis.
- Draft Fan Analysis. Black & Veatch identified the new fan requirements with high-level approximations for the new or modified ID or booster fans.
- Simplified AQCS Mass Balance. Simplified mass balances for the AQC process was completed to determine the level of reagent use and the quantity of byproduct produced.
- Black & Veatch identified new auxiliary electric loads with approximate values for recommended technologies.
- Chimney Analysis. A high-level analysis was performed to evaluate, for each air pollution control equipment option identified, modifications or replacement of the existing chimney.
- Constructability Review. A high-level constructability review was performed to assure that each conceptual site layout considers necessary access for construction without disrupting existing plant and AQC equipment. Construction and schedule are key considerations in the success of any major capital plan.
- Conceptual Equipment Arrangements. Black & Veatch produced overlays of existing site layout drawings supplied by E.ON to identify potential equipment locations (AQC equipment footprint boxes) for the approved AQC technologies. These layouts approximate the footprints and the real estate constraints.
- Schedule. Black & Veatch developed a general high-level project schedule (Level 1) including construction and erection plan of recommended AQC technologies.

The capital cost estimates were factored from recent detailed studies of similar coal fired applications and previous in-house design/build projects, include direct and indirect costs, and are stated in 2010 dollars. These costs also include allowances for auxiliary electric, draft fan upgrades, control system upgrades and other required BOP system upgrades and high-level estimates of capital cost for new stacks, induced draft (ID) and booster fans, and ductwork. Likewise, O&M costs were also estimated for the aforementioned equipment and were similarly based on data from either in-house design/build projects or, as in most case, were estimated based on a factor. The capital and O&M represent order-of-magnitude costs. The following sections briefly describe these costs.

3.3.1 Capital Costs Estimate

Direct costs consist of purchased equipment, installation, and miscellaneous costs including foundation, handling equipment, electrical, demolition, buildings, relocation costs, etc. The purchased equipment costs are the costs for purchasing the equipment, including taxes and freight. An itemized list of key components of the direct capital cost has been included in the costs for each feasible control technology described later in this report. The installation costs include construction costs for installing the new controls. The installation costs take into account the retrofit difficulty of the existing site configuration and condition and the installation requirements of the evaluated technology. Finally, the costs of miscellaneous items such as site preparation, buildings, and other site structures needed to implement the control technology are included.

Indirect costs are those costs that are not related to the equipment purchased but are associated with any engineering project, such as the retrofit of an AQC technology. Indirect costs addressed in this evaluation include the following:

- Contingency.
- Engineering.
- Owner's Cost.
- Construction Management.
- Startup and Spare Parts.
- Performance Tests.

The following sections briefly describe the indirect capital costs considered for this study.

3.3.1.1 Contingency. Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost development of a project. Costs assumed to be included in the contingency cost category are items such as possible redesign and equipment modifications, errors in estimation, unforeseen weather-related delays, strikes and labor shortages, escalation increases in equipment costs, increases in labor costs, delays encountered in startup, etc.

3.3.1.2 Engineering. Engineering costs include any services provided by an architect/engineer or other consultant for support, design, and procurement of the AQC project.

3.3.1.3 Owner's Cost. Table 3-2 lists possible Owner's costs for this category. The Owner's costs are identified as indirect costs. Some of the categories are not applicable to all of the evaluated technologies, but are representative of the typical expenditures that an Owner would experience as part of an AQC retrofit project.

3.3.1.4 Construction Management. Construction management services include field management staff such as support personnel, field contract administration, field inspection and quality assurance, project controls, technical direction, and management of startup. It also includes cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor-related insurance, performance bond, and liability insurance for equipment and tools.

3.3.1.5 Startup and Spare Parts. Startup services include the management of the startup planning and procedure and the training of personnel for the commissioning of the newly installed AQC technology. Also included are the general low-cost spare parts required for each AQC technology system. High-cost critical spare part components are kept only if recommended by the manufacturer; they are determined and accounted for on a case-by-case basis.

3.3.1.6 Performance Tests. Performance test services are typically required after every AQC technology addition to validate the performance of the emissions reduction system. The results of the performance tests are used to ensure compliance with performance guarantees and emissions limits.

Table 3-2
Typical Owner's Cost Categories

Project Development:
- Legal assistance
- Environmental permitting/offsets
- Public relations/community development
- Road modifications/upgrades

Financing:
- Debt service reserve fund
- Analyst and engineer

Owner's Project Management:
- Provide project management
- Perform engineering due diligence
- Prepare bid documents and select contractors and suppliers

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Construction all-risk insurance
- Auxiliary power purchase

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power purchase agreement
  - Interconnect agreements
  - Contract--procurement and construction
  - Property transfer

3.3.2 Annual O&M Cost Estimate

Annual O&M costs typically consist of both fixed and variable O&M costs. The following cost categories are a few of the fixed and variable costs considered:

- Reagent costs.
- Electric power costs.
- Makeup water costs.
- Wastewater treatment and byproduct disposal costs.
- Operating labor costs.
- Maintenance materials and labor costs.

The costs of reagent, electric power, makeup water, wastewater, and byproduct disposal are variable annual costs and are dependent on the specific control technology. O&M materials and labor are fixed annual costs.

The following sections briefly discuss some of the fixed and variable O&M costs considered for this study.

3.2.2.1 Reagent Costs. Reagent costs include the costs for the material, delivery of the reagent to the facility, and reagent preparation. Reagent costs are a function of the quantity of the reagent used and the price of the reagent. The quantity of reagent used will vary with the quantity of pollutant removed. Reagent costs were defined for the following reagents:

- Anhydrous ammonia.
- Limestone.
- Lime.
- Trona.
- Powdered Activated Carbon (PAC).

3.2.2.2 Electric Power Costs. Additional auxiliary power will be required to run some of the new control technology systems. The power requirements of each system vary, depending on the type of technology and the complexity of the system. Electric power costs include an increase in fan power caused by the flue gas pressure losses through the new equipment. The additional fan power was estimated with a basis of 90 percent fan efficiency and 80 percent motor efficiency.

3.2.2.3 Makeup and Service Water Costs. Makeup water or service water is required for some of the processes in the new control technology systems. Examples of water consumption include water to support AQC activities for the SO_2 scrubber systems.

3.2.2.4 Wastewater and Byproduct Disposal Costs. Some control technologies generate wastewater and/or byproduct that will require treatment or disposal. Examples of wastewater and disposal to support the AQC activities include the SO_2 scrubber systems and the pulse jet fabric filter (PJFF) systems.

3.2.2.5 Operating Labor Costs. Operating labor costs are developed by estimating the number and type of employees that will be required to run the new AQC equipment. This estimate was based on common industry practices. The labor cost was based on a fully loaded labor rate and 40 hours per work week.

Typically, a complex emissions control technology will require a combination of the following personnel:

- Supervisor.
- Control Room Operator.
- Roving Operator.
- Relief Operator.
- Laboratory Technicians.
- Equipment Operators.

3.2.2.6 Maintenance Materials and Labor Costs. The annual maintenance materials and labor costs are typically estimated as a percentage of the total equipment costs of the system. Based on typical electrical utility industry experience, maintenance materials were estimated to be between 1 and 5 percent of the total direct capital costs. Some initial recommended spare parts were included (assumed) in the capital costs. An annual maintenance value of 3 percent of the total direct capital costs was used as the basis for the yearly maintenance materials and labor cost. For technologies that replace a similar existing technology at the current plant site, a determination of the additional maintenance requirements was performed. If the required maintenance materials and labor were similar to the existing technology, no additional maintenance costs were credited for the new control technology.

3.4 Economic Data and Assumptions

The following are the economic data and assumptions used in the cost analysis.

3.4.1 Economic Data

Economic data were provided by E.ON for use in development of the annual O&M costs. However, some economic data were not available for some units/plants. Therefore, Black & Veatch assumed the highest value provided by E.ON as representative of the equivalent variable for any plant with missing economic data. The economic data are presented in Table 3-3. The assumed cost data have been denoted in bold-italic font and are summarized below:

- The limestone cost for Cane Run and Green River is $11.54/ton.
- The lime cost for Cane Run and Green River plant is $132.19/ton.

Table 3-3
Economic Evaluation Parameters(a)

	Economic Criteria																
Economic Parameters	**E.W. Brown**			**Ghent**				**Cane Run**			**Mill Creek**				**Trimble County**		**Green River**	
Unit Identification	**1**	**2**	**3**	**1**	**2**	**3**	**4**	**4**	**5**	**6**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Remaining Plant Life (years)	30			30				20			30				30		30	
Capacity Factor (percent)	44.00	62.00	57.00	81.00	71.00	78.00	77.00	60.00	62.00	54.00	68.00	70.00	75.00	75.00	85.00	87.00	26.00	32.00
Auxiliary Power Cost ($/MWh)	42.66	36.46	36.24	24.87	24.59	25.44	24.9	28.88	28.35	30.18	21.56	21.69	23.31	22.35	23.25	21.49	34.33	31.87
Limestone Cost ($/ton)	11.54			8.22				***11.54***(b)			7.54				8.24		***11.54***(b)	
Lime Cost ($/ton)	132.19			131.78				***132.19***(b)			118.13				131.78		***132.19***(b)	
Ash Disposal Cost ($/tonne)	***15***(b)			***15***(b)				***15***(b)			***15***(b)				***15***(b)		***15***(b)	
SCR Catalyst Replacement Cost ($/m^3)	***6,500***(b)			***6,500***(b)				***6,500***(b)			***6,500***(b)				***6,500***(b)		***6,500***(b)	
Ammonia Cost for SCR ($/ton)	***530.03***(b)			517.55				***530.03***(b)			530.03				522.7		***530.03***(b)	
Trona Cost ($/ton)	200.42			200.42				***200.42***(b)			195				***200.42***(b)		***200.42***(b)	
Halogenated PAC Cost ($/lb)	***1.1***(b)			***1.1***(b)				***1.1***(b)			***1.1***(b)				***1.1***(b)		***1.1***(b)	
Water Cost ($/1,000 gal)	***2***(b)			***2***(b)				***2***(b)			***2***(b)				***2***(b)		***2***(b)	
Fully-Loaded Labor Rate ($/h)	123,325			121,000				126,882			132,901				132,491		121,547	
Capital Escalation Rate (percent)	2.5																	
O&M Escalation Rate (percent)	2																	
Levelized Fixed Charge Rate or Capital Recovery Factor (percent)	12.17																	
Interest During Construction (percent)	4.5																	

(a) Utilities costs are as delivered costs.
(b) Economic variable was not provided by E.ON and are assumed data based on similar economic data for other E.ON plants.

- The ash disposal cost for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $15/ton.
- The selective catalytic reduction (SCR) catalyst replacement cost for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $\$6,500/m^3$.
- The anhydrous ammonia cost for E.W. Brown, Cane Run, and Green River is $530.03/ton.
- The trona cost for Cane Run, Trimble County and Green River is $200.42/ton.
- The halogenated PAC costs for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $1.1/lb.
- The water costs for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $2/1,000 gallons.

3.4.1 Economic Assumptions

Based on Black & Veatch's experience technical and economic assumptions were made to appropriately characterize costs for the study. These assumptions are briefly described, but are not limited to, the following:

1. The direct cost estimates reflect the following:
    - Costs for regulatory and environmental permitting were not included.
    - Costs for additional equipment studies were not included.
    - Regular supply of construction craft labor and equipment is available.
    - Normal lead-times for equipment deliveries are expected.
2. Compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) and their associated cost were not considered.
3. Costs for loss of generation for construction outage were not included as part of the indirect costs.
4. Annual operating cost estimates are based on operation at full-load conditions utilizing E.ON supplied load factors.
5. Sizing of AQC components and estimates of flue gas flow and pressure drops are developed from calculations based on the coal composition as provided by E.ON.

6. Sizing of AQC components is based on the AQC equipment being capable of achieving Best Available Control Technology emission levels. However, O&M costs were based on achieving the identified pollutant emission rates.
7. The cost estimate includes calculated values for escalation and contingency.
8. Owner's costs (project development, financing, etc.) are estimated as a percentage of the total capital cost.
9. Annual O&M costs associated with the AQC retrofit equipment are differential O&M costs associated with the equipment, rather than with the entire plant O&M costs.
10. Common economic components of each AQC technology are apportioned to the technologies rather than identified separately.
11. Neural networks (NNs) were assumed for all units as the proven and feasible control technology to reduce emissions of CO from the coal fired units[3]. For units less than 300 MW, a capital and O&M cost of $500,000 and $50,000, respectively, was assumed. For units greater than 300 MW, a capital and O&M cost of $1,000,000 and $100,000, respectively, was assumed.
12. H_2SO_4 (SO_3) emissions were not an identified pollutant in E.ON's emission matrix. However, due to generation of sulfuric acid mist[4] (H_2SO_4) (SO_3) from SO_2 to SO_3 conversion across the SCR technology catalyst, Black & Veatch included costs for a H_2SO_4 (SO_3) mitigation system for units with approved SCR AQC technologies.
13. Costs estimates have been included in the unit specific AQC equipment costs for AQC equipment that requires new reagent preparation systems, dewatering systems, or byproduct handling systems.

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[3] Neural networks are proven and feasible technologies to reduce CO emissions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation. It is recommended that detailed studies be performed to determine the potential benefit from NN installation.

[4] Emissions of H_2SO_4 (SO_3) were not included in the emission matrix as a primary pollutant requiring assessment for new AQC technology.

4.0 Control Cost Estimate (Capital and O&M)

The following sections describe the existing conditions, site visit observations, AQC recommendations, cost estimates, special considerations, and implementation schedules for each unit.

4.1 E.W. Brown - Units 1, 2, and 3

The E.W. Brown Station is located on Herrington Lake in Mercer County, Kentucky, between Shakertown and Burgin, off of Hwy 33. The station was constructed on the west side of Herrington Lake, the impoundment behind Dix Dam. The plant began commercial operation in 1957. The station includes three coal fired electric generating units with a total nameplate capacity of 747 MW gross. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems.

Unit 1 has a gross capacity of 110 MW and is equipped with old generation LNBs and cold side dry ESP for NO_x and PM control, respectively. Unit 2 has a gross capacity of 180 MW and is equipped with LNBs, OFA, and cold-side dry ESP for NO_x and PM control. Unit 3 has a gross capacity of 457 MW and is equipped with LNBs, OFA, and cold-side dry ESP for NO_x and PM control. E.ON is in the process of installing an SCR (in-service date, 2012) on Unit 3 to control NO_x and a common wet FGD scrubber for Units 1, 2, and 3 (in-service date, late 2010).

4.1.1 Site Visit Observations and AQC Considerations

At the E.W. Brown Generating Station, the Black & Veatch team met Brad Pabian (Mechanical Engineer), Barry Carman (Results Coordinator), and Ronald Gregory (Plant Manager) from E.ON. The following text is a narrative summary of the site visit conducted on May 13, 2010.

The installation of SCR on Unit 1 will require significant demolition and relocation of the circulating water system, service water piping, and soot blower air compressors tanks and modification of secondary air heater duct in the boiler building. This would require a significant outage time and is generally thought to be a difficult and expensive alternative. In order to achieve plantwide NO_x emission compliance with future regulatory requirements, it was decided by E.ON to install new generation low NO_x burners (LNBs) and overfire air (OFA) instead of SCR on Unit 1[5].

Installing SCR on Unit 2 will require demolishing the abandoned Unit 2 chimney, relocation of the storage tank, relocation of auxiliary transformer, demolition of the dust collector and associated ductwork and support steel, and relocation of underground utilities. The new SCR duct tie-ins to the existing Unit 2 air heater inlet duct will require boiler building structural steel bracing and girts to be modified to accommodate ductwork. The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR structures to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR modules.

Installing individual PJFF on Unit 1 and Unit 2 will require some demolition of ductwork and structural steel and relocation of ductwork and associated support steel for tie-in. Crane access around the footprint of the ID fans for Unit 1 and Unit 2 is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations. There is no real estate available for construction of PJFF on Unit 2, and the PJFF on Unit 2 will be elevated above the grade level and constructed above (downstream) the existing cold-side dry electrostatic precipitators (ESPs). For Unit 3, the new PJFF will be installed downstream of the existing cold-side dry ESP.

Installing individual PJFF on Unit 3 will require some demolition of ductwork and structural steel and relocation of ductwork and associated support steel for tie-in. It will also require relocation of underground utility lines.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

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[5] It should be noted that Black & Veatch originally recommended an SCR for E.W. Brown Unit 1. However, on May 21, 2010, E.ON approved LNB and OFA technology in lieu of SCR. E.ON later requested costs for SCR, which were provided separately on June 14, 2010.

4.1.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, PM, CO, Hg, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 1. These AQC technologies include installation of new generation LNBs, OFA, and PAC injection coupled with a new PJFF located downstream of the existing ESP. The new generation LNB and OFA system can reduce NO_x emissions to 0.30 lb/MBtu. The new PJFF will be installed downstream of the existing cold-side dry ESP. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 2. These AQC technologies include the installation of new SCR and PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be into the new ductwork upstream of the PJFF. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

As previously noted, E.ON is in the process of installing an SCR (in-service date, 2012) on Unit 3 that will be capable of reducing NO_x emissions to 0.11 lb/MBtu or lower. To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 3. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

Also noted, a common wet FGD scrubber for Units 1, 2, and 3 is in the process of being built (in-service date, late 2010) at E.W. Brown. This wet FGD will serve to meet or exceed the SO_2 target emission of 0.25 lb/MBtu and the HCl target emission of 0.002 lb/MBtu. Therefore, no new SO_2 or HCl emission control technologies are proposed for these units.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.1.3 Capital and O&M Costs

The total estimated capital cost to upgrade E.W. Brown Unit 1, Unit 2, and Unit 3 with recommended technologies are \$44,000,000 (\$400/kW), \$149,000,000 (\$826/kW), and \$67,000,000 (\$148/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-1, 4-2, and 4-3. Detailed cost summaries are included in Appendix H.

Table 4-1
Capital and O&M Cost Summary – E.W. Brown Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Overfire Air	$767,000	$7	$132,000	$225,000
Low NO_x Burners	$1,156,000	$11	$0	$141,000
Fabric Filter	$40,000,000	$364	$1,477,000	$6,345,000
PAC Injection	$1,599,000	$15	$614,000	$809,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	**$44,022,000**	**$400**	**$2,273,000**	**$7,631,000**

Table 4-2
Capital and O&M Cost Summary – E.W. Brown Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
SCR	$92,000,000	$511	$3,278,000	$14,474,000
Fabric Filter	$51,000,000	$283	$1,959,000	$8,166,000
Lime Injection	$2,739,000	$15	$1,155,000	$1,488,000
PAC Injection	$2,476,000	$14	$1,090,000	$1,391,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$148,715,000**	**$826**	**$7,532,000**	**$25,630,000**

Table 4-3
Capital and O&M Cost Summary – E.W. Brown Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
Fabric Filter	$61,000,000	$133	$3,321,000	$10,745,000
PAC Injection	$5,426,000	$12	$2,330,000	$2,990,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$67,426,000**	**$148**	**$5,751,000**	**$13,957,000**

4.1.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirements will need to be considered for booster fan or upgraded ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.
- **Ash Handling**--Additional new ash handling system will be needed for Units 1, 2, and 3 PJFF.
- **Ammonia Storage**--Ammonia storage for Unit 3 can be utilized to supply Unit 2 ammonia for new SCR.
- **H_2SO_4 (SO_3) Emissions**--Consideration was given to Unit 3's H_2SO_4 (SO_3) emissions although these emissions were not a primary focus for this study.
- **Footprint**:
  - There is very limited space to install a new SCR on Unit 2. Therefore, the SCR will be located between the existing plant wall and the original Unit 2 stack. To achieve this, it will be necessary to demolish the existing mechanical dust collector and demolish the abandoned Unit 2 stack.
  - Because of the limited available footprint, the PJFF on Unit 2 will be located above the existing dry ESP.
- **Constructability Challenges**:
  - The new SCR duct tie-ins to the existing Unit 2 air heater inlet duct will require boiler building structural steel bracing and girts to be modified to accommodate ductwork.
  - The new Unit 2 SCR support structure and reactor structure will require extensive relocation/demolition of existing plant components.
  - The relocation or protection of field fabricated tank located in base of abandoned Unit 2 chimney shell.
  - The demolition of Unit 2 chimney.

- The demolition of the dust collection ductwork located along the northeast exterior wall of Unit 2 boiler building.
- The relocation of Unit 2 auxiliary transformer located outside of the northeast exterior wall of Unit 2 boiler building.
- Extensive underground investigation will be required to identify operating utilities prior to installing new foundations for Unit 2 fabric filter structural steel support frame.
- The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR and fabric filter structures to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR and fabric filter modules.

4.1.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Unit 1

The Unit 1 arrangement (Appendix G) will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF and the installation of the LNBs and OFA will require a plant outage.

Unit 2

Because of the tight space constraints, particularly for the installation sequencing of the SCR and somewhat for the PJFF, the construction efforts for Unit 2 will likely require an extended single outage or two shorter outages with the SCR being installed during the first outage. This allows for the major construction of the PJFFs with the plant in operation and requiring another shorter outage for the tie-in.

Unit 3

The Unit 3 arrangement shown on the drawing will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF will require a plant outage.

4.1.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at E.W. Brown is nominally $260,000,000 ($1,400/kW). The O&M and levelized annual costs of new AQC equipment at E.W. Brown is nominally $15,600,000 and $47,000,000, respectively.

4.2 Ghent - Units 1, 2, 3, and 4

The Ghent Generating Station is located approximately 9 miles northeast of Carrolton, Kentucky. Ghent, which began commercial operations in February 1, 1974, is situated on approximately 1,670 acres.

The plant is a four unit pulverized coal fired electric power plant with gross capacity of 2,007 MW. Two of the boilers are manufactured by Combustion Engineering and two by Foster Wheeler. The Combustion Engineering boilers are tangential-fired, balanced draft forced circulation boilers, and Foster Wheeler boilers are balanced draft natural circulation boilers. Unit 1 has a gross capacity of 541 MW and is equipped with LNBs and SCR for NO_x control; cold-side dry ESP for PM control; wet FGD system for SO_2 control, and lime injection system for H_2SO_4 or SO_3 control. Unit 2 has a gross capacity of 517 MW and is equipped with LNBs, OFA for NO_x control; hot-side dry ESP for PM control; and wet FGD system for SO_2 control. Units 3 and 4 have a gross capacity of 523 MW and 526 MW, respectively, and are equipped with LNBs, OFA, and low-dust SCR for NO_x control; hot-side dry ESP for PM control; wet FGD system for SO_2 control, and trona injection system for H_2SO_4 (SO_3) control.

4.2.1 Site Visit Observations and AQC Considerations

At the Ghent Generating Station, the Black & Veatch team met David Pennybaker (Project Engineer), Carla Piening (Senior Scientist), Stephen Nix (Lead Engineer), and Jeff Joyce (Plant Manager) from E.ON. The following text is a narrative summary of the site visit conducted on May 11, 2010.

Installing PJFF for Units 1 and 2 requires significant site preparation and demolition. Crane access is difficult at Units 1 and 2 because of a low overhead piperack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or relocated. Lattice boom crawler crane booms will need to be final assembled and reeved at the working location. Access lanes around Units 1 and 2 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area. Current arrangement for Unit 2 fabric filters require a section of bypass ductwork to be installed in order to isolate/demolish existing ductwork/duct supports and provide the required footprint for the new equipment. Tie-in portions of this work scope must be accomplished during early plant outages. The new PJFF will be elevated aboveground. Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.

Installing PJFF on Units 3 and 4 requires removal of underground utility lines. Current arrangement for Unit 3 fabric filters requires an extensive length of inlet/outlet ductwork to be routed above and across the existing Unit 3 and 4 ESPs. Access around the footprint of the dry ESPs is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations. Existing underground electrical manholes, water wells, storm sewer boxes and piping, and circulating cooling water piping all run in the proposed footprint for Unit 4 fabric filter. The electrical manholes, water wells, and storm sewer piping will need to be relocated in order to install the foundations for the Unit 4 fabric filter structural frame.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.2.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, PM, CO, Hg, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Unit 1. These AQC technologies include installation of a new PAC injection system coupled with a new PJFF located downstream of the existing dry ESP. The new PJFF will be elevated aboveground. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Unit 1 has an existing SCR to control NO_x emissions to the future NO_x emission target of 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on this unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Unit 2. These AQC technologies include installation of new SCR system, new PAC injection system coupled with a new PJFF located downstream of the existing ID fans. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New sorbent (lime/trona) injection for H_2SO_4 abatement needs to be installed and will be into the ductwork upstream of the hot-side dry ESP. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Units 3 and 4. These AQC technologies include installation of new PAC injection system coupled with a new PJFF located downstream of the existing ID fans of Units 3 and 4. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Units 3 and 4 have existing SCRs to control NO_x emissions to the future NO_x emission target of 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on these units.

All four Ghent units have existing individual wet FGDs that will meet the SO_2 target emission of 0.25 lb/MBtu or lower and the HCl target emission of 0.002 lb/MBtu or lower. No new SO_2 or HCl emission controls are considered for this study, and there is no need to replace existing stacks.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.2.3 Capital and O&M Costs

The total estimated capital costs to upgrade Ghent Unit 1, Unit 2, Unit 3, and Unit 4 with recommended technologies are $138,000,000 ($256/kW), $360,000,000

($696/kW), $145,000,000 ($278/kW), and $124,000,000 ($236/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-4, 4-5, 4-6, and 4-7. Detailed cost summaries are included in Appendix H.

4.2.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirements will need to be considered for booster fan or upgraded ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.

Table 4-4
Capital and O&M Cost Summary – Ghent Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$131,000,000	$242	$5,888,000	$21,831,000
PAC Injection	$6,380,000	$12	$4,208,000	$4,984,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$138,380,000**	**$256**	**$10,196,000**	**$27,037,000**

Table 4-5
Capital and O&M Cost Summary – Ghent Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$227,000,000	$439	$7,078,000	$34,704,000
Fabric Filter	$120,000,000	$232	$5,002,000	$19,606,000
Lime Injection	$5,483,000	$11	$2,775,000	$3,442,000
PAC Injection	$6,109,000	$12	$2,880,000	$3,623,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$359,592,000**	**$696**	**$17,835,000**	**$61,597,000**

Table 4-6
Capital and O&M Cost Summary – Ghent Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$138,000,000	$264	$6,122,000	$22,917,000
PAC Injection	$6,173,000	$12	$4,134,000	$4,885,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$145,173,000**	**$278**	**$10,356,000**	**$28,024,000**

Table 4-7
Capital and O&M Cost Summary – Ghent Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$117,000,000	$222	$5,363,000	$19,602,000
PAC Injection	$6,210,000	$12	$3,896,000	$4,652,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$124,210,000**	**$236**	**$9,359,000**	**$24,476,000**

- **Ash Handling**--Additional new ash handling system will be needed for Units 1, 2, 3, and 4 PJFF. It is understood that a new byproduct ash system is currently being studied at the plant. Contingent on the final determination of installed AQC technology, further investigation and coordination of ash handling systems will be required.
- **H_2SO_4 (SO_3) Emissions--** Consideration was given to Unit 1, 2, 3, and 4 3's H_2SO_4 (SO_3) emissions although these emissions were not a primary focus for this study.
- **Ammonia Storage**--Ammonia storage for Unit 3 can be utilized to supply Unit 2 ammonia for new SCR.
- **Footprint**:
  - Unit 1 and Unit 2 PJFF do not have any real estate available on the grade elevation for construction. Hence these PJFF will be elevated above the ground level.
  - The Unit 3 PJFF could be installed between boilers of Units 2 and 3, adjacent to the new Unit 2 SCR. However, plant personnel want to keep this area clear for staging and equipment lay-down purposes. Hence, Unit 3 PJFF will be installed on the south side of the Unit 4 dry ESP, with booster fan or ID fan upgrades because there is very limited space available between the ID fan outlet and wet scrubber inlet on the west side.

- **Constructability Challenges**:
  - Crane access is difficult at Units 1 and 2 because of low overhead piperack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or relocated. Lattice boom crawler crane booms will need to be final assembled and reeved at the working location.
  - Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.
  - Access lanes around Units 1 and 2 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area.
  - The current arrangement for Unit 2 fabric filters requires a section of bypass ductwork to be installed in order to isolate/demolish existing ductwork/duct supports and provide the required footprint for the new equipment. Tie-in portions of this work scope must be accomplished during early plant outages.
  - The current arrangement for Unit 3 fabric filters requires an extensive length of inlet/outlet ductwork to be routed above and across the existing Unit 3 and 4 dry ESPs. Access around the footprint of the dry ESPs is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations.
  - Crane access will be restricted around the tie-in for Unit 3 fabric filter inlet/outlet ductwork.
  - Existing underground electrical manholes, water wells, storm sewer boxes and piping, and circulating cooling water piping all run in the proposed footprint for Unit 4 fabric filter. The electrical manholes, water wells, and storm sewer piping will need to be relocated in order to install the foundations for the Unit 4 fabric filter structural frame.

4.2.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Units 1, 2, 3, and 4

The arrangement shown on the drawing will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF will require a plant outage. Unit 2 arrangements shown on the drawing will allow for the majority of the construction of the SCR to occur without taking a plant outage. The tie-in of the SCR will require a plant outage.

4.2.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Plant Ghent is nominally $767,400,000 ($1,500/kW). The O&M and levelized annual costs of new AQC equipment at Ghent is nominally $47,800,000 and $141,000,000, respectively.

4.3 Cane Run - Units 4, 5, and 6

The Cane Run Generating Station is located at 5252 Cane Run Road (State Highway 1849), about 8 miles southwest of Louisville, Kentucky. The facility includes approximately 500 acres between Cane Run Road and the Ohio River. The pulverized coal fired electric power plant began commercial operation in 1954 in response to the demand for electricity by industries that were located in Louisville during World War II. Three of its six units are now retired. Units 4, 5, and 6 are currently active and have a gross capacity of 610 MW. Unit 4 was placed in service in 1962, Unit 5 in 1966, and Unit 6 in 1969.

Units 4, 5, and 6 have a gross capacity of 168 MW, 181 MW, and 261 MW, respectively, and are equipped with LNBs or OFA (Units 4 and 5 have LNBs but no OFA, Unit 6 has OFA but no LNBs) for NO_x control; cold-side dry ESP for PM control; and wet FGD system for SO_2 control.

4.3.1 Site Visit Observations and AQC Considerations

At the Cane Run Station, the Black & Veatch team met Keron Miller, Mike Hensley, and Chuck Hance from E.ON. The following text is a narrative summary of the site visit conducted on May 11, 2010.

Cane Run Units 4, 5, and 6 have existing LNBs and FGD emission control devices. Performance of the aging FGD scrubbers is sufficient to meet the current stack emission limit, and NO_x emissions are currently controllable to the existing limits using only LNBs. Current PM emissions are controlled by the combination of the efficient ESPs and FGD designs. In general, the plant is capable of maintaining the current emissions levels but requires new AQC technologies to meet the future pollutant emission limits and have operational flexibility. According to plant personnel, upgrades to the existing scrubber towers are currently being considered that would increase scrubbing efficiency to meet the future emission standards. However, due to space constraints, upstream control devices (e.g., SCR, fabric filter) require real estate that precludes use of the existing FGD vessels. Plant personnel also pointed out that maintenance of boiler tubes is considerably exacerbated because of lower oxygen combustion zone to minimize NO_x emissions.

New AQC technologies for each unit will be identical except for the sizing of components. Each unit will need new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, PJFF, and wet FGD. A new single chimney will house three lined wet stacks; one liner for each unit. The SCR will increase the H_2SO_4 (SO_3) concentration in the flue gas and exacerbate the potential for corrosion on the cooler surfaces downstream of the air heater. Lime will be added downstream of the air heater (upstream of the PJFF) to minimize the impact of acid components in the flue gas on downstream surfaces. Injection of PAC is also recommended upstream of the PJFF.

Installation of SCR on Units 4, 5, and 6 would become a constraining factor from a construction perspective. There is not sufficient room to successfully install the connections from and back into the ductwork after the economizer section on any of the units. Any attempt to do so would compromise the performance of the SCR and would also be an operational challenge over the life of the plant. This decision alone leads to the difficult alternative of selectively demolishing the existing back end AQC equipment one unit at a time. This means that for an extended period of time only two of the three units would be operational. Scheduled outages on the remaining units will reduce plant availability even more.

Installation of SCR technology requires access to the hopper/ductwork exiting the economizer sections of each boiler. The hot fly ash laden flue gas must be transported to the SCR and ducted from the SCR to the air heater inlet. The existing equipment at this plant is too close-coupled in this area to allow adequate access for attaching these new ducts. The space required to install new AQC technologies is currently occupied by the existing wet FGD components and stacks. Any new technologies should be installed directly in lieu of the existing equipment. This requires a complete demolish and removal of existing equipment prior to installation of the new equipment. This will cause an extended outage as shown in the AQC replacement schedule in Subsection 4.3.5. Demolition of the existing and construction of new AQC equipment is planned in series for each unit. This lengthens the unit outage time and increases the cost associated to meet new emission standards.

Due to lack of available space to add the new equipment, the new AQC technologies required for the three units will need to use the existing footprint. Demolition of existing equipment will need to be completed prior to construction of new equipment to provide space for installation of the new equipment. Demolition of all existing AQC equipment one unit at a time from the economizer section back is proposed to minimize outage time (at least 24 month outages are estimated). Power lines above each unit will need to be moved for safe demolition and construction. There appear to be adequate areas available for equipment laydown during construction.

Demolition and construction of each unit will be in series. For example, Unit 5 could be taken out of service and demolished from the economizer to the FGD equipment. The common stack and other common equipment (ammonia storage area, common reaction tank) could be built prior to the outage. Moving of transmission lines could also be accomplished prior to the outage along with preparation of lay-down areas and moving of needed underground utilities.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.3.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, SO_2, PM, CO, Hg, HCl and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Cane Run Units 4, 5, and 6. The AQC technologies identified for each of the three units are the same and include installation of a new SCR system to reducing NO_x to 0.11 lb/MBtu or lower, new PJFF to reduce PM emissions to 0.03 lb/MBtu or lower; a new wet FGD system to reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower; a new halogenated PAC injection to reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu, new sorbent (lime) injection system for H_2SO_4 abatement, and New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.3.3 Capital and O&M Costs

The total estimated capital costs to upgrade Cane Run Unit 4, Unit 5, and Unit 6 with recommended technologies are $253,000,000 ($1,508/kW), $266,000,000 ($1,468/kW), and $341,000,000 ($1,306/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-8, 4-9, and 4-10. Detailed cost summaries are included in Appendix H.

4.3.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new wet FGD is required. There will be a significant change in the amount of wastewater produced by the wet FGD. A new or a possible upgrade in wastewater treatment facility is required.
- **Wet FGD Byproduct Handling**--There will be a significant change in the amount of byproduct produced by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in byproduct handling system is required.
- **Wet FGD Reagent Preparation System**--There will be a significant change in the amount of reagent required by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in reagent preparation system is required.
- **Ash Handling**--Cane Run has limited new space available for landfill of waste (ash and scrubber solids). Onsite landfill space is expected to be consumed in less than 20 years. Additional new ash handling system or a possible upgrade in the ash handling system will be required.
- **Ammonia Storage**--A new ammonia storage facility will be required for new SCRs. Detailed investigation or study will be required to identify the site location for ammonia storage and supply.

Table 4-8
Capital and O&M Cost Summary – Cane Run Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$63,000,000	$375	$2,219,000	$9,886,000
Wet FGD	$152,000,000	$905	$8,428,000	$26,926,000
Fabric Filter	$33,000,000	$196	$1,924,000	$5,940,000
Lime Injection	$2,569,000	$15	$983,000	$1,296,000
PAC Injection	$2,326,000	$14	$1,087,000	$1,370,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$253,395,000**	**$1,508**	**$14,691,000**	**$45,529,000**

Table 4-9
Capital and O&M Cost Summary – Cane Run Unit 5

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$66,000,000	$365	$2,421,000	$10,453,000
Wet FGD	$159,000,000	$878	$8,789,000	$28,139,000
Fabric Filter	$35,000,000	$193	$2,061,000	$6,321,000
Lime Injection	$2,752,000	$15	$1,089,000	$1,424,000
PAC Injection	$2,490,000	$14	$1,120,000	$1,423,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$265,742,000**	**$1,468**	**$15,530,000**	**$47,871,000**

Table 4-10
Capital and O&M Cost Summary – Cane Run Unit 6

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$86,000,000	$330	$2,793,000	$13,259,000
Wet FGD	$202,000,000	$774	$10,431,000	$35,014,000
Fabric Filter	$45,000,000	$172	$2,672,000	$8,149,000
Lime Injection	$3,873,000	$15	$1,367,000	$1,838,000
PAC Injection	$3,490,000	$13	$1,336,000	$1,761,000
Neural Networks	$500,000	$2	$50,000	$111,000
Total	$340,863,000	$1,306	$18,649,000	$60,132,000

- **Footprint**--The new AQC equipment will be installed where the existing AQCS equipment is currently operating.
- **Constructability Challenges**:
  - Ingress from highways - Multiple power lines need to be raised to accommodate high loads.
  - Barge unloading is not economically feasible.
  - Existing overhead power lines are routed over each unit and must be relocated for crane access.
  - 4 kV building and CT switchyard needs to be relocated.
  - Entire Unit 5 "back-end" must be dismantled prior to starting any work on Unit 4.
  - There is a need for multiple mob/de-mob/outages for tie-ins and access to build new AQC equipment.
  - Underground utility interferences/relocations.
  - Aboveground utility interferences/relocations.
  - Need for areas to build ammonia storage, ash handling systems, limestone handling, reagent preparation dewatering (ancillary systems).
  - Extended outages (entire plant) needed to accommodate construction of new AQC systems.
  - Demolition must be performed in multiple phases followed by extensive earthwork activities to bring existing site up to proper elevation.
  - Soils must be tested and stabilized for heavy lift crane operations.
  - Space is very limited around units; the most efficient use of modularization will be compromised.

4.3.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Units 4, 5, and 6

Plant life is restricted at Cane Run because of the amount of available land required for landfill of waste products. Installation of new AQC equipment is made particularly difficult by the close-coupling of existing equipment. B&V proposes to demolish the existing dry ESP and FGD equipment one unit at a time to make room for the new equipment. B&V estimates that this will require an extended construction outage of approximately 24 months per unit. One time-saving benefit is provided by construction of a single chimney with three liners.

4.3.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Cane Run is nominally $860,000,000 ($4,300/kW). The O&M and levelized annual costs of new AQC equipment at Cane Run is nominally $48,900,000 and $153,500,000, respectively.

4.4 Mill Creek - Units 1, 2, 3, and 4

The Mill Creek Station is located in southwestern Jefferson County, approximately 10.5 miles southwest of the city of Louisville, Kentucky, on a 509 acre site. Mill Creek Station includes four coal fired electric generating units with a gross total generating capacity of 1,608 MW. Mill Creek Station Unit 1 was placed in service in 1972, Mill Creek Station Unit 2 was placed in service in 1974, and Mill Creek Station Units 3 and 4 were each placed in service at 4 year intervals afterward in 1978 and 1982, respectively.

The Mill Creek Station consists of four coal fired electric generating units. All four boilers fire high sulfur bituminous coal. Each Mill Creek Station unit is composed of one GE reheat tandem compound, double-flow turbine with a condenser and hydrogen-cooled generator. Units 1 and 2 each consist of one Combustion Engineering subcritical, balanced draft boiler and have a gross capacity of 330 MW each and are equipped with LNBs and OFA for NO_x control; a cold-side dry ESP for PM control, and a wet FGD for SO_2 and HCl control. Units 3 and 4 each consist of one Babcock & Wilcox (B&W) balanced draft, Carolina type radiant boiler and have a gross capacity of 423 MW and 525 MW, respectively, and are equipped with LNBs and SCR for NO_x control; a cold-side dry ESP for PM control and a wet FGD for SO_2 and HCl control.

4.4.1 *Site Visit Observations and AQC Considerations*

At the Mill Creek Station, the Black & Veatch team met Mike Kirkland, Michael Buckner, Marc Blackwell, Alex Betz, Tiffany Koller, and Bill Moehrke from E.ON. The following text is a narrative summary of the site visit conducted on May 12, 2010.

Mill Creek Units 1 and 2 require a complete new set of AQC system equipment. Units 3 and 4 have existing SCR to control NO_x emissions to 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on Units 3 and 4 based on the identified emission levels. Units 3 and 4 have an existing cold-side dry ESP which will be retained and used for pre-filtration and fly ash sales.

The option to modify the existing wet FGD equipment and use of additives was considered plausible to meet the new emission target. However, Black & Veatch concluded that new limestone scrubbing technology would provide a more reliable long-term emission control technology to meet and exceed the study's SO_2 emission target considering the current state of the existing scrubbers and also the impact on the wastewater treatment facility. Additionally, there is no need to replace the existing wet stacks, and these stacks will be reused for all the four units.

Installation of SCR on Units 1 and 2 would require demolition of the existing dry ESPs to allow space for installation of a new SCR reactor and ductwork. Black & Veatch engineers believe that there is not sufficient room to successfully install the connections from and back into the air heater after the economizer section on either of the units. The new pre-filter dry ESP could be designed for minimal efficiency (~ 90 percent) to reduce size and allow fly ash to help build cake on the downstream bags of the new PJFF. The new PJFF will be stacked above the pre-filter dry ESP. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be routed into the new ductwork upstream of the new cold-side dry ESP. The existing dry ESP will be demolished and a new cold-side dry ESP will be installed for pre-filtration and fly ash sales. These new components could be installed on-line prior to demolition of the existing dry ESP. Once the tie-in to the new PM control devices is completed (New ID fan required), the units can be brought back online for demolition of the existing dry ESP and installation of the new SCR. Segments of the new FGD could begin construction during this period. Tie-in of the new SCR, ductwork, and new FGD would then allow demolition of existing FGD components, if needed. Units 1 and 2 will require new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, cold-side dry ESP, PJFF, and wet FGD. A phased construction approach as described above is necessary for Units 1 and 2 due to site real estate constraints and to reduce the ‘loss of generation’ aspect of the capital project.

Units 3 and 4 are particularly challenging with respect to finding a footprint for the new AQC equipment that did not require extremely long outages for demolition of existing equipment. Units 3 and 4 have limited space available for construction. The existing rail road tracks and the coal conveyors are the biggest challenges for these units. The new equipment will occupy land currently used as a roadway and historically used for rail. The roadway will need to be moved to provide future plant access. One set of inner tracks will remain for trains to continue to move coal throughout the plant.

Installation of AQC equipment for Units 1 and 2 requires phased installation and demolition activities. Installation of new PJFF and new Wet FGD on Units 3 and 4 will require the scrubber towers to be split to 2 x 50-60 percent capacity absorbers and the PJFFs be stacked and will be installed downstream of the existing cold-side dry ESP. This will avoid the expensive elevated construction option to create a tunnel over the road and rail. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be into the ductwork upstream of the existing cold-side dry ESP. The existing dry ESP will remain in service for pre-filtration and fly ash sales. Units 3 and 4 will require new booster fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, PJFF, and wet FGD systems. Existing power transmission lines would need to be moved for construction. There appears to be space available for addition of another tank to the existing ammonia tank farm if needed. It may be possible to simply increase the number of deliveries of anhydrous ammonia to account for the added demand of the new SCRs on Units 1 and 2.

The most imperative site constraint relating to the selection of post-combustion emission control technologies at Mill Creek is that greater than 80 percent of all solid waste is trucked offsite for use in other applications. Offsite transportation of solid waste minimizes onsite landfill needs and thereby helps extend plant life expectations. Therefore, because of the landfill issues, pre-filter dry ESPs are necessary for all units to mitigate the landfill challenge at Mill Creek as the collected ash will be disposed off to another location off site as a possible recycle material. Otherwise the use of a dry ESP for pre-filtration is not required for PM emissions control as new PJFFs are designed as full size PJFFs and not polishing filtration technology.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.4.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x (only on Units 1 and 2), PM, SO_2, CO, Hg, HCl, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Mill Creek Units 1 and 2. These AQC technologies include installation of new SCR and PAC injection coupled with a new PJFF located downstream of the new dry ESP. Also a new wet FGD system will be required. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Mill Creek Units 3 and 4. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. Also, a new wet FGD system will be required. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.4.3 Capital and O&M Costs

The total estimated capital cost to upgrade Mill Creek Units 1 and 2 with recommended technologies are is $518,000,000 ($1,569/kW) each. The total estimated capital costs to upgrade Mill Creek Units 3 and 4 with recommended technologies are $513,000,000 ($1,212/kW) and $596,000,000 ($1,135/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-11, 4-12, 4-13, and 4-14. Detailed cost summaries are included in Appendix H.

Table 4-11
Capital and O&M Cost Summary – Mill Creek Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,366,000	$15,171,000
Wet FGD	$297,000,000	$900	$14,341,000	$50,486,000
Fabric Filter	$81,000,000	$245	$3,477,000	$13,335,000
Electrostatic Precipitator	$32,882,000	$100	$3,581,000	$7,583,000
Lime Injection	$4,480,000	$14	$2,024,000	$2,569,000
PAC Injection	$4,412,000	$13	$2,213,000	$2,750,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,102,000**	**$92,116,000**

Table 4-12
Capital and O&M Cost Summary – Mill Creek Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,401,000	$15,206,000
Wet FGD	$297,000,000	$900	$14,604,000	$50,749,000
Fabric Filter	$81,000,000	$245	$3,518,000	$13,376,000
Electrostatic Precipitator	$32,882,000	$100	$3,664,000	$7,666,000
Lime Injection	$4,480,000	$14	$2,117,000	$2,662,000
PAC Injection	$4,412,000	$13	$2,340,000	$2,877,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,744,000**	**$92,758,000**

Table 4-13
Capital and O&M Cost Summary – Mill Creek Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$392,000,000	$927	$18,911,000	$66,617,000
Fabric Filter	$114,000,000	$270	$4,923,000	$18,797,000
PAC Injection	$5,592,000	$13	$3,213,000	$3,894,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$512,592,000**	**$1,212**	**$27,147,000**	**$89,530,000**

Table 4-14
Capital and O&M Cost Summary – Mill Creek Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$455,000,000	$867	$21,775,000	$77,149,000
Fabric Filter	$133,000,000	$253	$5,804,000	$21,990,000
PAC Injection	$6,890,000	$13	$3,858,000	$4,697,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$595,890,000**	**$1,135**	**$31,537,000**	**$104,058,000**

4.4.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID/booster fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new wet FGD is required for all the Units. There will be a significant change in the amount of waste water produced by the wet FGD. A new or a possible upgrade in wastewater treatment facility is required.

- **Wet FGD Byproduct Handling**--There will be a significant change in the amount of byproduct produced by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in byproduct handling system is required.
- **Wet FGD Reagent Preparation System**--There will be a significant change in the amount of reagent required by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in reagent preparation system is required.
- **Ash Handling**--Additional new ash handling system or a possible upgrade in the ash handling system will be required.
- **Ammonia Storage**--Detailed investigation or study will be required to identify if a new ammonia storage facility is required or an existing ammonia storage facility can be upgraded for accommodating Units 1 and 2 ammonia supply.
- **Biomass Utilization**--Black & Veatch is currently completing a biomass utilization study for Mill Creek. Should it be determined that biomass will be considered as a fuel source in one or more units at the plant, a detailed investigation or study will be required to identify potential affect to the approved AQC equipment and how these many affect the aforementioned costs.
- **Footprint**—For units 1 and 2 the SCR will be installed where the existing dry ESP equipment is currently operating. For units 1, 2, 3, and 4 existing scrubbers can be retired in place to save costs or demolished to create access.
- **Constructability Challenges**:
    - Barge unloading is not economically feasible.
    - Overhead power lines and at least two transmission towers must be moved.
    - Numerous underground utility interferences/relocations.
    - Numerous aboveground utility interferences/relocations.
    - Very limited access around units due to existing AQC systems.
    - Multiple mobilization/demobilization (very selective) dismantling operations are needed to ensure tie-in work is accomplished efficiently.
    - Building between Units 1 and 3 from Unit 1 work will present logistical problems for both plant work and construction.

- Access/height restrictions will dictate the magnitude of modularization that can be utilized.
- Warehouse and loading dock on Unit 2 side must be relocated.
- High complexity of ancillary systems routing to avoid interference with existing AQC systems.
- Ground stability will need to be verified and modified to accommodate heavy lift cranes.
- Multiple plant outages will be needed for tie-ins because of utilizing existing scrubbers, etc., throughout project.
- Ductwork routing is more extensive due to the layout of the existing plant and existing AQC systems in use.
- Space will be a premium for excavations/foundations/duct steel erection.
- Large existing concrete foundations will need to be removed to accommodate equipment.
- Outage windows are very short and limited.
- Site constraints due to the existing railroad and roadway exist.

4.4.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Units 1 and 2

The new dry ESP, PJFF, and ID fans on Units 1 and 2 can be installed with temporary ductwork to connect back to the air heater and to the existing wet FGD during a short outage. This will allow the existing dry ESPs to be demolished and the new SCRs and new wet FGD equipment to be constructed with the units remaining online. The remainder of the new equipment can then be tied into existing ductwork during a normal outage period.

Units 3 and 4

The new AQC equipment for these units can be installed without extensive off-line construction related outages. The tie-in of new ductwork can be scheduled to occur during planned unit outages.

4.4.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Mill Creek is nominally $2,100,000,000 ($5,500/kW). The O&M and levelized annual costs of new AQC equipment at Mill Creek is nominally $117,500,000 and $378,500,000, respectively.

4.5 Trimble County - Units 1 and 2

Trimble County Generating Station Unit 1 is a pulverized coal fired power plant located approximately 5 miles west of Bedford, Kentucky. Unit 1 began commercial operation in December 23 1990. Unit 2, a 760 MW coal plant, is under construction on the site and is due to be completed on June 15, 2010. Unit 1 consists of one Combustion Engineering (CE) tangential balanced draft, forced circulation boiler and one General Electric (GE) reheat double-flow steam turbine with a hydrogen-cooled generator.

Unit 1 has a gross capacity of 547 MW and is equipped with LNBs, OFA, and SCR for NO_x control; a cold-side dry ESP for PM control and a wet FGD for SO_2 and HCl control. Unit 2 is a new coal fired unit, has a gross capacity of 750 MW, and is equipped with LNBs, OFA, and SCR for NO_x control; boiler combustion optimization and NNs for CO control; a cold-side dry ESP for PM control, a PJFF with PAC injection for Hg and dioxin/furan control, a wet FGD for SO_2 and HCl control and a wet ESP for H_2SO_4 (SO_3) control.

4.5.1 Site Visit Observations and AQC Considerations

At the Trimble County Station, the Black & Veatch team met Kenny Craigmyle (Project Engineer) and Haley Turner (Chemical Engineer) from E.ON. The following text is a narrative summary of the site visit conducted on May 12, 2010.

The Trimble County plant is the newest plant in the E.ON fleet and Unit 1 has AQC technologies already exceeding operation capabilities of other E.ON coal fired units. Unit 2 is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Thus, the Trimble County plant is already generally capable of meeting nearly all the defined pollutant emission targets. However, it has been determined that Unit 1 will need to add AQC technology to control emissions of Hg and dioxin/furan.

Installing a PJFF on Unit 1 will require demolition of an existing abandoned tower crane foundation and multiple runs of electrical duct bank which covers a large percentage of the area within the footprint proposed to install foundations for the Unit 1 fabric filter support frame. Extensive underground investigation will be required to identify operating utilities prior to installing new foundations.

Plant personnel indicated that the variable speed controller for the existing ID fans has been replaced and has additional capacity beyond what is currently required. This should be verified during any preliminary engineering for a PJFF installation project.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by

E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.5.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Trimble County Unit 1. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The existing cold-side dry ESP is capable of meeting the future PM emission limit of 0.03 lb/MBtu or lower; however, for Hg and dioxin/furan removal and to continue fly ash sales, a new PJFF would be required. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new PJFF will be elevated above the grade level and will be installed downstream of the existing cold-side dry ESP. The existing dry ESP will be kept in service for pre-filtration and fly ash sales. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the new PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

As previously discussed, Unit 2 is currently in startup mode to test the unit's systems prior to becoming commercially operational. It has been assumed that this unit, and its existing AQC equipment, will meet the identified pollutant emission limits, and no new AQC technologies will be required.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.5.3 Capital and O&M Costs

The total estimated capital cost to upgrade Trimble County Unit 1 with recommended technologies is $136,000,000 ($248/kW). Capital, O&M, and levelized annual costs are shown in Table 4-15. Detailed cost summaries are included in Appendix H.

Table 4-15
Capital and O&M Cost Summary – Trimble County Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$128,000,000	$234	$5,782,000	$21,360,000
PAC Injection	$6,451,000	$12	$4,413,000	$5,198,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$135,451,000**	**$248**	**$10,295,000**	**$26,780,000**

4.5.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for upgrading the ID fans to accommodate the additional pressure drop of the new PJFF.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.
- **Ash Handling**--Additional new ash handling system will be needed for PJFF.
- **Ammonia Storage**--No new ammonia storage is required.
- **Footprint**--The new PJFF will be elevated and installed above the existing cold-side dry ESP.
- **Constructability Challenges**--An existing abandoned tower crane foundation and multiple runs of electrical duct bank cover a large percentage of the area within the footprint proposed to install foundations for the Unit 1 fabric filter support frame. Extensive underground investigation will be required to identify operating utilities prior to installing new foundations.

4.5.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Unit 1

The new PJFF can be installed without extensive construction related outages. The tie-in of new ductwork can be scheduled to occur during planned unit outages.

4.5.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Trimble County is nominally $135,500,000 ($250/kW). The O&M and levelized annual costs of new AQC equipment at Trimble County are nominally $10,300,000 and $26,800,000, respectively.

4.6 Green River - Units 3 and 4

The Green River Generating Station is located 3 miles north of Central City in Muhlenberg County. The station is a four unit, coal fired electric generating station with a total nameplate capacity of 168 MW net. Units 3 and 4 are pulverized coal fired generating units. Units 1 and 2 were decommissioned in January 2002 and are, therefore, not included within this review. Units 3 and 4 have a gross capacity of 71 MW and 109 MW, respectively, and are equipped with LNBs for NO_x control; and dry ESP (cold-side dry ESP for Unit 3 and hot-side dry ESP for Unit 4) for PM control.

4.6.1 Site Visit Observations and AQC Considerations

At the Green River Station, the Black & Veatch team met Travis Harper, Jim Edelen, and Eileen Saunders from E.ON. The following text is a narrative summary of the site visit conducted on May 13, 2010.

The Green River plant is the oldest and most uncontrolled coal fired plant in the E.ON fleet. Green River Units 1 and 2 have been retired in place since 1948. Units 3 and 4 were put into service in 1954 and 1959, respectively. Both remaining Units 3 and 4 are load following. Low load is approximately 40 MW for each unit, and (according to plant personnel) it is not unusual for both units to sit at low loads for extended periods just to support line voltage drop.

This low load operating issue for Units 3 and 4 impacts the flue gas temperature at the economizer outlet of both units. To properly operate a new SCR, significant economizer bypass will be needed to keep the SCR inlet temperature from dropping below design limits. The Installation of new AQC systems on Units 3 and 4 would require relocation of overhead power lines and one tower for Unit 4 AQC Equipment. Underground and aboveground utility interferences need to be relocated for Unit 3 AQC equipment. The existing Unit 3 tubular air heater will be replaced with a new regenerative type air heater. Flue gas will be diverted from the economizer section to the SCR inlet duct and will flow vertically upward to the top of the SCR. The SCR will be located above the new air heater and will require economizer bypass to control the flue gas temperature to the SCR inlet. Flue gas flow from the new air heater to the bottom of the new CDS vessel where the bed will be kept fluidized across the load range using recirculated gas from the PJFF outlet. The scrubbed flue gas will be drawn through the CDS and PJFF with a new ID fan that will direct clean flue gas to the new Unit 3 carbon steel stack. Solids collected in the PJFF (fly ash + unreacted reagent) will be recycled back to the CDS inlet to optimize reagent utilization.

The existing Unit 3 cold-side dry ESP and Unit 4 hot-side dry ESP were put into service in 1974. The Unit 4 hot-side dry ESP outlet duct will be connected to the new

SCR by new ductwork. Flue gas will travel upward to the top of the SCR and be routed back to the existing regenerative air heater flue gas inlet. Flue gas will travel out from the air heater to the bottom of the CDS. Scrubbed gas will then travel into two new PJFF housings located on each side of the CDS vessel. New ID fans will draw flue gas through the PJFF housings and deliver the clean flue gas to the new Unit 4 stack located between the new AQC equipment and the existing building wall. The hardware and footprint for PAC injection equipment is minimal and will be located near the air heater outlet ductwork before it splits into two PJFF inlet ducts.

Green River Units 3 and 4 require a complete new set of AQC system equipment along with two new carbon steel dry stacks.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.6.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Green River Units 3 and 4. These AQC technologies include installation of a new SCR and PAC injection coupled with a new circulating dry scrubber (CDS) and PJFF located downstream of the air heater. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The CDS and PJFF will reduce PM emissions to 0.03 lb/MBtu or lower, SO_2 emissions to 0.25 lb/MBtu or lower, and HCl emissions to 0.002 lb/MBtu or lower. The existing cold-side dry ESP on Unit 3 will be retired in place/demolished and existing hot-side dry ESP on Unit 4 will be kept in service for pre-filtration of fly ash. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the CDS, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Units 3 and 4 will require new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, CDS, and PJFF.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.6.3 Capital and O&M Costs

The total estimated capital cost to upgrade Green River Units 3 and 4 with recommended technologies are $69,000,000 ($966/kW) and $98,000,000 ($900/kW) respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-16 and 4-17. Detailed cost summaries are included in Appendix H.

Table 4-16
Capital and O&M Cost Summary – Green River Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$29,000,000	$408	$1,040,000	$4,569,000
CDS-FF	$38,000,000	$535	$6,874,000	$11,499,000
PAC Injection	$1,112,000	$16	$323,000	$458,000
Neural Network	$500,000	$7	$50,000	$111,000
Total	**$68,612,000**	**$966**	**$8,287,000**	**$16,637,000**

Table 4-17
Capital and O&M Cost Summary – Green River Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$42,000,000	$385	$1,442,000	$6,553,000
CDS-FF	$54,000,000	$495	$10,289,000	$16,861,000
PAC Injection	$1,583,000	$15	$515,000	$708,000
Neural Network	$500,000	$5	$50,000	$111,000
Total	**$98,083,000**	**$900**	**$12,296,000**	**$24,233,000**

4.6.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new CDS-PJFF is required for all the Units. The makeup water system may require a possible upgrade.
- **CDS Byproduct Handling**--There will be a significant amount of byproduct produced by the CDS because of the high amount of sulfur removal from the coal. A new byproduct handling system is required.

- **CDS Reagent Preparation System**--There will be a significant amount of reagent required by the CDS because of the high amount of sulfur removal from the coal. A new reagent preparation system is required.
- **Ammonia Storage**--A new ammonia storage facility will be required for new SCRs. Detailed investigation or study will be required to identify the site location for ammonia storage and supply.
- **Footprint**--The new AQC equipment will be installed in the new location as shown on the equipment layout drawing included in Appendix G.
- **Constructability Challenges**:
  - Relocation of some existing transmission lines and one tower will be needed for safe installation of new AQC equipment.
  - Relocation of the existing generator set will be needed to make space available for the new AQC equipment.
  - Some underground utility interferences/relocations.
  - Some aboveground utility interferences/relocations.

4.6.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

Unit 3 and 4

The plant has available space for the new AQC equipment, and the new AQC equipment can be installed without extensive off-line construction related outages.

4.6.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Green River is nominally $167,000,000 ($1,900/kW). The O&M and levelized annual costs of new AQC equipment at Green River are nominally $20,600,000 and $40,900,000, respectively.

Appendix A
E.ON Environmental Matrix

Estimated Requirements Under Future New Environmental Regulations

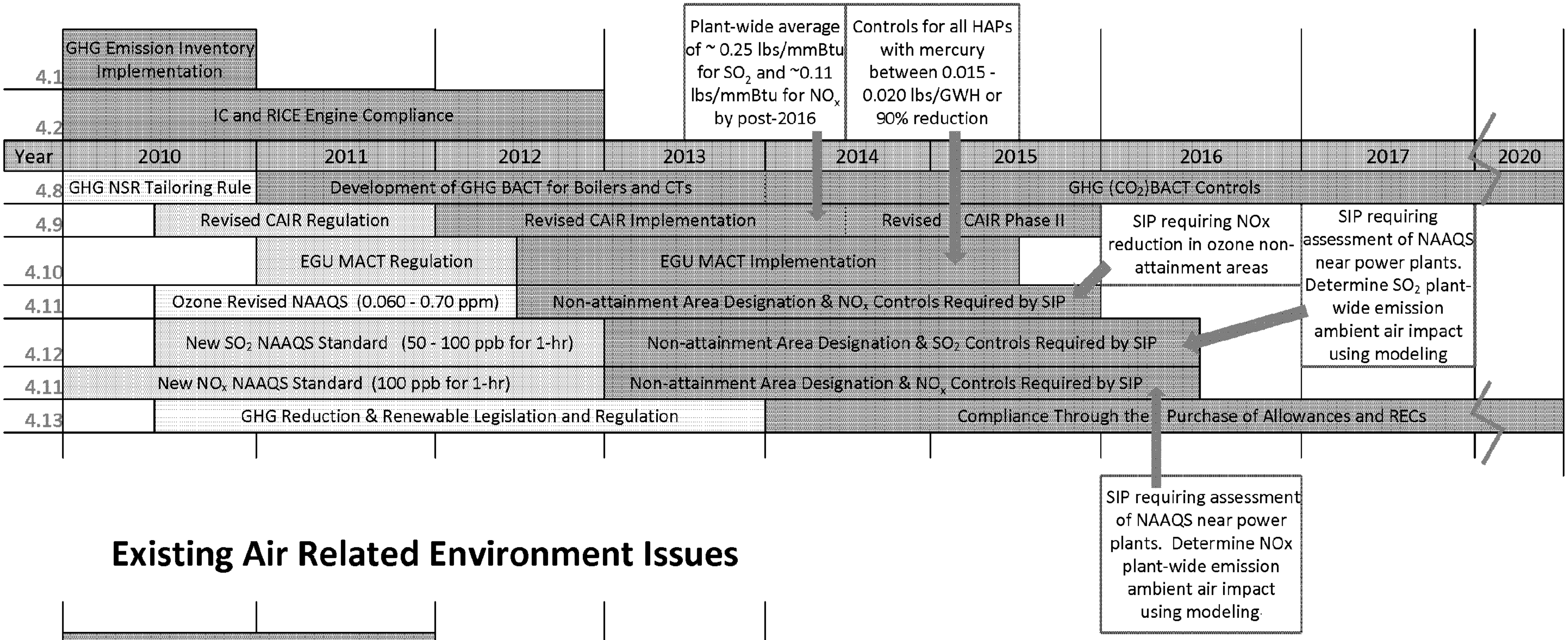
Task No.	Program Name	Regulated Pollutants			Unit/Plant Averaging	Forcasted Date for Compliance
		Pollutant	Limit	Units		
4.1	GHG Inventory	No additional limits			N/A	Spring - 2010
4.2	New & Existing Engine NSPS and RICE MACT	PM NO_x VOC CO	Varies by Model Year and Horsepower. Certified to meet Tier III, Interim Tier IV or Tier IV		Unit	Spring 2013 for existing MACT & at installation for new NSPS
4.3	Mill Creek BART	MC3 - SAM MC4 - SAM	64.3 76.5	lbs/hour lbs/hour	Unit	During - 2011
4.4	Jefferson Co. STAR Reg.	metals in fuels (As) 20 - 50 ppm or ~$1x10^{-5}$ lbs/mmBtu emission rate			Plant	Spring - 2012
4.5 & 4.6	Brown Consent Decree	PM SO_2 NO_x SAM	0.03 97% 0.07 /0.08 110 -220	lbs/mmBtu Removal lbs/mmBtu lbs/mmBtu	Unit 3	SO_2 & PM - December, 2010 NO_x & SAM - December, 2012
4.7	Ghent NOVs	SAM	3.5 - 10	ppm	Unit	During - 2012
4.8	GHG NSR	GHG	Energy Efficiency Projects		Unit/Plant	January, 2011
4.9	Revised CAIR	SO_2 NO_x	0.25 0.11	lbs/mmBtu lbs/mmBtu	Plant	Beginning in 2014
4.10	New EGU MACT	Mercury	90% or 0.012	Removal lbs/GWH	Plant	January, 2015; with 1-yr extension - January, 2016
		Acids (HCl)	0.002	lbs/mmBtu	Unit	
		Metals (PM)	0.03	lbs/mmBtu		
		Metals (As)	$0.5 x 10^{-5}$	lbs/mmBtu		
		Organics (CO)	0.02	lbs/mmBtu		
		Dioxin/Furan	$15 x 10^{-18}$	lbs/mmBtu		
4.11	Jefferson Co. Ozone Non-attainment	NO_x	5 - 10 % reduction	NOx emissions	County-wide	Spring - 2016
4.11	New 1-hour NAAQS for NO_x	NO_x	To be determined based on modeling	lbs/hours	Plant	During - 2015
4.12	New 1-hour NAAQS for SO_2	SO_2	To be determined based on modeling	lbs/hours	Plant	Spring - 2016
4.13	GHG Reduction & Renewables	GHG	To be determined based on modeling	tons/year	Fleet	Beginning in 2014
Plan Risk	$PM_{2.5}$ Emission Reductions	PM2.5 (Condensables)	To be determined based on modeling	lbs/mmBtu	Unit/Plant	After 2013
4.14	CWA 316(a)	Thermal impacts	Biological Studies	N/A	Plant	Starting in 2010
4.15	CWA 316(b)	Withdraw impacts	Biological Studies	N/A	Plant	Starting in 2012
4.16	New Effluent Standard	Metals, Chlorides, etc.	EPA anaylsis is just beginning	EPA anaylsis is just beginning	Plant	During - 2015
4.17	CCR Classification	Toxic Metals	Handle dry in landfill; possible closing existing ash ponds in 5 years		Plant	Beginning in 2012;

▨ - New requirements have been finalized e·on | U.S.

Major Assumptions (Air)

Generation
2011-2013 MTP

Air Related Environmental Regulatory Program Implementation



4.1 GHG Emission Inventory Implementation

4.2 IC and RICE Engine Compliance

Plant-wide average of ~ 0.25 lbs/mmBtu for SO_2 and ~0.11 lbs/mmBtu for NO_x by post-2016

Controls for all HAPs with mercury between 0.015 - 0.020 lbs/GWH or 90% reduction

Year | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2020

4.8 GHG NSR Tailoring Rule | Development of GHG BACT for Boilers and CTs | GHG (CO_2)BACT Controls

4.9 Revised CAIR Regulation | Revised CAIR Implementation | Revised CAIR Phase II

4.10 EGU MACT Regulation | EGU MACT Implementation

4.11 Ozone Revised NAAQS (0.060 - 0.70 ppm) | Non-attainment Area Designation & NO_x Controls Required by SIP

4.12 New SO_2 NAAQS Standard (50 - 100 ppb for 1-hr) | Non-attainment Area Designation & SO_2 Controls Required by SIP

4.11 New NO_x NAAQS Standard (100 ppb for 1-hr) | Non-attainment Area Designation & NO_x Controls Required by SIP

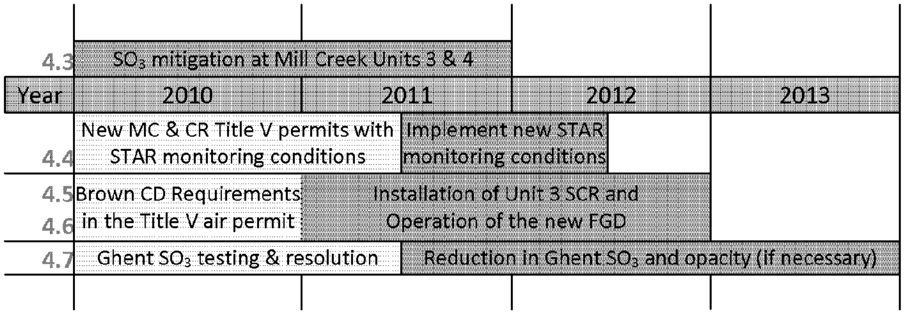
4.13 GHG Reduction & Renewable Legislation and Regulation | Compliance Through the Purchase of Allowances and RECs

SIP requiring NOx reduction in ozone non-attainment areas

SIP requiring assessment of NAAQS near power plants. Determine SO_2 plant-wide emission ambient air impact using modeling

SIP requiring assessment of NAAQS near power plants. Determine NOx plant-wide emission ambient air impact using modeling.

Existing Air Related Environment Issues



4.3 SO_3 mitigation at Mill Creek Units 3 & 4

Year | 2010 | 2011 | 2012 | 2013

4.4 New MC & CR Title V permits with STAR monitoring conditions | Implement new STAR monitoring conditions

4.5 4.6 Brown CD Requirements in the Title V air permit | Installation of Unit 3 SCR and Operation of the new FGD

4.7 Ghent SO_3 testing & resolution | Reduction in Ghent SO_3 and opacity (if necessary)

Note:

If the environmental action is above the "Year" row, then regulatory requirements are finalized.

▦ - Year of occurrence

☐ - Regulatory requirements are still being developed

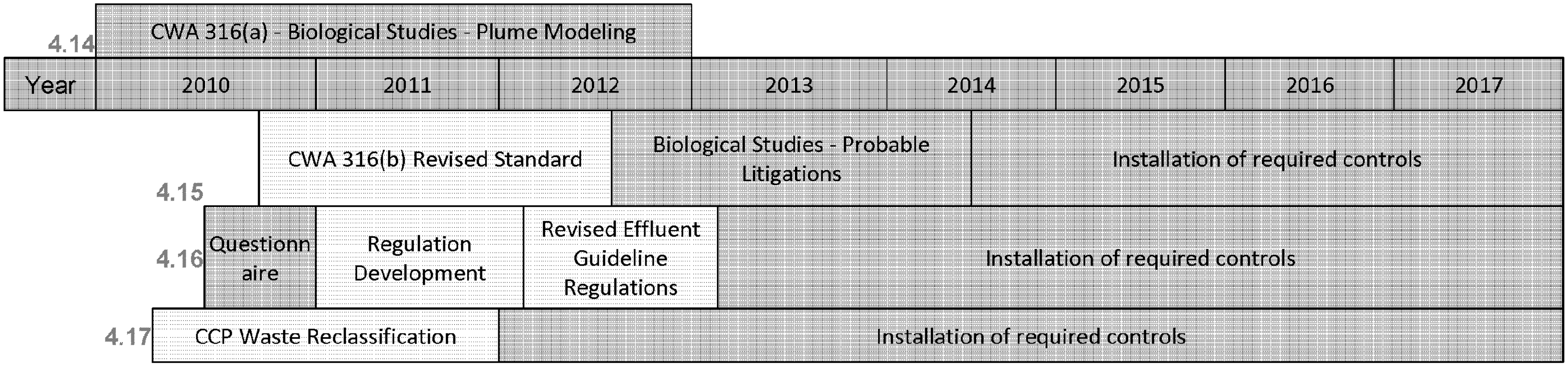
▤ - Requirements are still being developed, but an indication of major impact

▩ - In the implementation phase (engineering design & equipment construction)

April, 2010; Revision 1

e·on | U.S. Major Assumptions (Land & Water) Generation 2011-2013 MTP

Land & Water Related Environmental Regulatory Program Implementation



4.14 CWA 316(a) - Biological Studies - Plume Modeling

Year 2010 2011 2012 2013 2014 2015 2016 2017

4.15 CWA 316(b) Revised Standard | Biological Studies - Probable Litigations | Installation of required controls

4.16 Questionnaire | Regulation Development | Revised Effluent Guideline Regulations | Installation of required controls

4.17 CCP Waste Reclassification | Installation of required controls

▦ - Year of occurrence
☐ - Regulatory requirements are still being developed
░ - Requirements are still being developed, but an indication of major impact
▩ - In the implementation phase (engineering design & equipment construction)

Appendix B
E.ON Unit Specific Data

E.W. Brown

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**		**Notes**
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: __________ Owner: __________
Unit __________ Project: __________

Plant Size and Operation Data: (provide for each unit)	**Unit 1**	**Unit 2**	**Unit 3**	**Unit X**		**Notes**
Maximum (Design) Fuel Burn Rate	4 * 14.91 Tons/hr	4 * 22.6 Tons/hr	5 * 46.75 Tons		MBtu/hr	# Pulv * Pulv rating
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Wall-Fired	Tangential Fired	Tangential Fired			
Boiler Manufacturer	B&W	CE	CE			
Net MW Rating (specify plant or turbine MW)	102	169	433		MW	Dispatch Generator Ratings
Gross MW Rating	110	180	457		MW	Dispatch Generator Ratings
Net Unit Heat Rate	9802	9855	9516		Btu/kWh	S&L Design Heat Balance
Net Turbine Heat Rate	8104	8149	8019		Btu/kWh	S&L Design Heat Balance
Boiler SO2 to SO3 Conversion Rate (if known)	na	na	na		%	
Fly Ash/Bottom Ash Split	80/20	80/20	80/20		%	Typical values used on other reports
Flue Gas Recirculation (FGR)						
Installed? (Y/N)	N	N	N			
In operation? (Y/N)						
Flue Gas Recirculation (if installed)					%	
Type of Air Heater	Ljungstrom	Ljungstrom	Ljungstrom			
Air Heater Configuration (horizontal or vertical flow or shaft)	Vertical	Vertical	Vertical			
Design Pressure/Vacuum Rating for Steam Generator +/-					in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-					in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)						
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)						
Neural Network Installed? (Y/N)						
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)						
Extra Capacity available in DCS?						
Historian Manufacturer						
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear						
(SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)						
Operating Conditions						
Economizer Outlet Temperature	650	730	730		°F	Typical data from PI historian
Economizer Outlet Pressure	-8	-3.7	-5		in wg.	Typical data from PI historian
Excess Air or Oxygen at Economizer Outlet (full load/min load)	5/8 O2	3/4 O2	2.8/3.3		%	Typical data from PI historian
Economizer Outlet Gas Flow	na	na	na		acfm	
					lb/hr	
Air Heater Outlet Temperature	350	330	340		°F	Typical data from PI historian
Air Heater Outlet Pressure	-14	-8	-18		in wg.	Typical data from PI historian; Unit 1 has back pass dampers
Particulate Control Equipment Outlet Temperature	340	320	330		°F	Typical data from PI historian
Particulate Control Equipment Outlet Pressure	-18	-12	-19		in wg.	Typical data from PI historian
FGD Outlet Temperature (if applicable)	na	na	na		°F	Typical data from PI historian
FGD Outlet Pressure (if applicable)	na	na	na		in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

NOx Emissions	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Emissions Limit	0.5	0.45	0.07		lb/MBtu	Units 1 & 2 on averaging plan for Nox so this is target rather
Type of NOx Control (if any) - LNB, OFA, etc.	lnb	lnb, ofa	lnb, ofa			
Current NOx Reduction with existing controls	na	na	na		%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)						
Reagent Cost					$/ton	
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit	0.254	0.162	0.03		lb/MBtu	Title V permit for 1 & 2, Consent Decree Unit 3
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold Side ESP	Cold Side ESP	Cold Side ESP			
Oxygen Content of Flue Gas @ Air Heater Outlet	na	na	na		%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	na	na	na		%	
Current Emissions	0.241	0.068	0.07		lb/MBtu	Latest compliance PM testing
Fly Ash Sold (Y/N) - See Economic Section	n	n	n			
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	5.15	5.15	.1 or 97%		lb/MBtu	Title V permit for 1 & 2, Consent Decree Unit 3
Type of Emission Control - wet or semi-dry FGD (if any)						
Current Emissions	2.5	2.5	2.5		lb/hr	Typical Value from CEMS (typically varies from 1.5 to 3.5 wit
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: ________ Owner: ________

Unit ________ Project: ________

ID Fan Information (at Full Load):	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
ID Fan Inlet Pressure	-14	-8	-18		in wg.	
ID Fan Discharge Pressure	0.5	0.5	0.5		in wg.	
ID Fan Inlet Temperature	340	320	330		F	
Oxygen Content of Flue Gas @ ID Fan Inlet	na	na	na		%	
ID Fan Motor Voltage (Rated)	13200	2300	13200		volts	
ID Fan Motor Amps (Operating)	na	400	na		A	
ID Fan Motor Amps (Rated)	see fan curve	see fan curve	see fan curve		A	
ID Fan Motor Power (Rated)	see fan curve	see fan curve	see fan curve		hp	
ID Fan Motor Service Factor (1.0 or 1.15)	see fan curve	see fan curve	see fan curve			
Chimney Information:						
Flue Liner Material						
Flue Diameter					ft	
Chimney Height					ft	
Number of Flues						

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ____________________ Owner: ____________________

Unit ____________________ Project: ____________________

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Ghent

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**		**Notes**
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)	No		
Natural gas line (into the station) capacity (if applicable)	No		
Current Lost on Ignition (LOI)			
Start-up Fuel	# 2 Fuel Oil		
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate		B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		tangential	tangential	ont/back wall fired	ont/back wall fired		
Boiler Manufacturer		CE	CE	FW	FW		
Net MW Rating (specify plant or turbine MW)						MW	
Gross MW Rating		541	517	523	526	MW	
Net Unit Heat Rate		10557	8904	11180	11070	Btu/kWh	
Net Turbine Heat Rate		8733	7565	8404	8439	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		1.50%		1.95%	2.20%	%	
Fly Ash/Bottom Ash Split						%	
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		No	No	No	No		
In operation? (Y/N)		No	No	No	No		
Flue Gas Recirculation (if installed)		No	No	No	No	%	
Type of Air Heater		Lungstrom	Lungstrom	Lungstrom	Lungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)		vertical	vertical	vertical	vertical		
Design Pressure/Vacuum Rating for Steam Generator	+/-	35	26	35	35	in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	35"V	30" V	30" V	30" V	in wg.	

Electrical / Control

DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Emerson	Emerson	Emerson	Emerson	
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	Ovation	Ovation	Ovation	Ovation	
Neural Network Installed? (Y/N)	No	No	No	No	
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	n/a	n/a	n/a	n/a	
Extra Capacity available in DCS?	yes	yes	yes	yes	
Historian Manufacturer	Emerson	Emerson	Emerson	Emerson	
Additional Controls from DCS or local PLC w/tie-in	yes	yes	yes	yes	
Transformer Rating for Intermediate Voltage Switchgear					
(SUS's) and Ratings of Equipment in These Cubicles					
Auxiliary Electric Limited (Y/N)					

Operating Conditions

Economizer Outlet Temperature	729	610	731	791	°F	
Economizer Outlet Pressure	-323	-5.07	-5.12	-4.51	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	3	3.5	3.5	3.3	%	
Economizer Outlet Gas Flow	3775	4147	4506	4076	acfm	
					lb/hr	
Air Heater Outlet Temperature	345	309	315	309	°F	
Air Heater Outlet Pressure	-22.4	-18.6	-36.1	-29.4	in wg.	
Particulate Control Equipment Outlet Temperature	361	605	708	770	°F	
Particulate Control Equipment Outlet Pressure	-25.7	-10.8	-0.92	-0.82	in wg.	
FGD Outlet Temperature (if applicable)	125	83	130	128	°F	
FGD Outlet Pressure (if applicable)	1.65	1.45	2	1.56	in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

NOx Emissions	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**		**Notes**
Emissions Limit	0.45	0.4	0.46	0.46	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB/OFA	LNB/OFA	LNB/OFA		
Current NOx Reduction with existing controls	SCR	SCR	SCR	SCR	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	anhydrous	anhydrous	anhydrous	anhydrous		
Reagent Cost					$/ton	
Current Emissions	330	1300	330	330	lb/hr	
	930	850	4800	850	ton/yr	
	0.04	0.35	0.04	0.04	lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side ESP	Hot side ESP	Hot side ESP	Hot side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.025 lbs/mmbtu	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	No	No	No	No		
ESP						
Specific Collection Area (SCA)	153	223	328	328	ft^2/1000 acfm	
Discharge Electrode Type	rigid	wire	wire	wire		
Supplier	PECO	GE	GE	GE		
Efficiency	99.2	99			%	
No. of Electrical Sections	4 in series	4 in series	7 in series	7 in series		
% of Fly Ash Sold	0	0	0	0	%	
Fabric Filter						
Air to Cloth Ratio (net)	N/A				ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	5.67 lbs/mmbtu (24 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	wet FGD	wet FGD	wet FGD	wet FGD		
Current Emissions	600	600	1120	600	lb/hr	
	1400	2100	1400	1400	ton/yr	
	0.15	0.2	0.15	0.15	lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	yes	yes	yes	yes		

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

ID Fan Information (at Full Load):	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**		**Notes**
ID Fan Inlet Pressure	-22.5	-18.7	-36	-28.9	in wg.	
ID Fan Discharge Pressure	6.08	11.4	5.94	14.6	in wg.	
ID Fan Inlet Temperature	358	309	322	309	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3	3.5	3.5	3.17	%	
ID Fan Motor Voltage (Rated)	4160	6600	13200	4000	volts	
ID Fan Motor Amps (Operating)	990	670	410	1385	A	
ID Fan Motor Amps (Rated)	1113	953	535	1020	A	
ID Fan Motor Power (Rated)	9000	12500	13600	8000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1.15	1.15		
Chimney Information:						
Flue Liner Material	fiber glass	brick	brick	fiber glass		Ghent 2 and 3 share a common stack-each unit is mixed
Flue Diameter	29'6"	34'5"	34'5"	29'6"	ft	into a common exit flue
Chimney Height	660	580	580	660	ft	
Number of Flues	1	2	2	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis

Technical evaluations performed to support recent consent decree activity

Existing Plant/AQC system general design and performance issues

Full detailed boiler front, side, and rear elevation drawings

Boiler Design Data (Boiler Data Sheet)

Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)

Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)

Plant Arrangement Drawings (showing column row spacing)

CEM Quarterly and Annual Data (required if base emissions are to be verified)

Recent Particulate Emission Test Report (If available)

Current Mercury Testing Results (If available)

Current Site Arrangement Drawing

Foundation Drawings and/or Soils Report

Underground Utilities Drawings

Plant One Line Electrical Drawing

Fan Curves for Existing ID Fans (including current system resistance curve)

Acceptable Fan Operating Margins

Plant Outage Schedule

overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Cane Run

Black & Veatch AQCS Information Needs

Power Plant: Cane Run

Owner: Louisville Gas & Electric

Unit:

Project:

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**	**Notes**
Carbon	61.4	59.8	63.14	
Hydrogen	4.3	4.09	4.3	
Sulfur	3.2	2.23	3.2	
Nitrogen	1.3	1.26	1.5	
Oxygen	6.5	6.62	7.44	
Chlorine	0.1			
Ash	10.8	9.13	11.67	
Moisture	12.4	11.92	15.18	
Total	100	95.05	106.43	
Higher Heating Value, Btu/lb (as received)	10921.64	10391	11673	
Ash Mineral Analysis (% by mass):				
Silica(SiO_2)	46.02	42.41	49.07	
Alumina (Al_2O_3)	23.27	20.81	25.64	
Titania (TiO_2)	1.09	0.99	1.21	
Phosphorous Pentoxide (P_2O_5)	0.255	0.16	0.34	
Calcium Oxide (CaO)	1.211	0.88	1.89	
Magnesium Oxide (MgO)	0.98	0.87	1.14	
Sodium Oxide (Na_2O)	0.3	0.22	0.44	
Iron Oxide (Fe_2O_3)	22.97	17.48	27.84	
Sulfur Trioxide (SO_3)	0.95	0.52	1.7	
Potassium Oxide (K_2O)	2.6	2.24	2.93	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium 46.75 %

Arsenic 15.47 %

Mercury 0.09 % or ppm

Other LOI %

Natural gas firing capability (if any at all) Y

Natural gas line (into the station) capacity (if applicable)

Current Lost on Ignition (LOI)

Start-up Fuel Gas

Ash Fusion Temperature

Initial Deformation 2025.56 °F

Softening 2211.44 °F

Hemispherical 2332.11 °F

Hardgrove Grindability Index 62

Black & Veatch AQCS Information Needs

Power Plant: Cane Run
Unit
Owner: Louisville Gas & Electric
Project:

Plant Size and Operation Data: (provide for each unit)	**CR4**	**CR5**	**CR6**		**Notes**
Maximum (Design) Fuel Burn Rate	1601.9	1753.4	2395.7	MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Wall	Wall	Wall		
Boiler Manufacturer	CE	Riley	CE		
Net MW Rating (specify plant or turbine MW)	155	168	240	MW	
Gross MW Rating	168	181	261	MW	
Net Unit Heat Rate	10340	10458	10789	Btu/kWh	
Net Turbine Heat Rate	8414	8429	8625	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)	-	-	-	%	
Fly Ash/Bottom Ash Split	80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)					
Installed? (Y/N)	Y	N	N		
In operation? (Y/N)	Y	N	N		
Flue Gas Recirculation (if installed)				%	
Type of Air Heater	Ljungstrom	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)	Horizontal	Horizontal	Horizontal		
Design Pressure/Vacuum Rating for Steam Generator +/-	1800/3.5	1800/1.5	2400/3.5	in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-	no data	20" H2O/-8.75	no data	in wg.	
Electrical / Control					
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Honeywell	Honeywell	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	TDC3000/Experion	TDC3000/Experion	TDC3000/Experion		
Neural Network Installed? (Y/N)	Y	Y	Y		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	Neuco	Neuco	Neuco		
Extra Capacity available in DCS?	Y	Y	Y		
Historian Manufacturer	Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in					
Transformer Rating for Intermediate Voltage Switchgear					
(SUS's) and Ratings of Equipment in These Cubicles					
Auxiliary Electric Limited (Y/N)	N	N	N		
Operating Conditions					
Economizer Outlet Temperature	580.45	630.24	617.2	°F	
Economizer Outlet Pressure				in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)				%	
Economizer Outlet Gas Flow				acfm	
				lb/hr	
Air Heater Outlet Temperature	369.22	299.15	317.59	°F	
Air Heater Outlet Pressure				in wg.	
Particulate Control Equipment Outlet Temperature	132.6	128.4	132.8	°F	Summer design Temperature
Particulate Control Equipment Outlet Pressure				in wg.	ID Fan Suction Pressure
FGD Outlet Temperature (if applicable)	127			°F	
FGD Outlet Pressure (if applicable)				in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Cane Run
Owner: Louisville Gas & Electric
Unit:
Project:

NOx Emissions	**CR4**	**CR5**	**CR6**		**Notes**
Emissions Limit	0.3372	0.3934	0.3276	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB	OFA		
Current NOx Reduction with existing controls				%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	N/A	N/A	N/A		
Reagent Cost				$/ton	
Current Emissions	0.337	0.384	0.286	lb/hr	
				ton/yr	
				lb/MBtu	
Particulate Emissions					
Emissions Limit	0.11	0.11	0.11	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF					
Oxygen Content of Flue Gas @ Air Heater Outlet	5.78	5.82	4.53	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet				%	
Current Emissions	0.041	0.034	0.024	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	N	N	N		
ESP					
Specific Collection Area (SCA)				ft^2/1000 acfm	
Discharge Electrode Type	0.109" Copper Bessemer	0.109" Copper Bessemer			
Supplier	Research-Cottrell	Research-Cottrell	Buell Engineering		Original supplier
Efficiency	99.1	96.1	99.2	%	
No. of Electrical Sections	48		49		
% of Fly Ash Sold	N/A	N/A	N/A	%	
Fabric Filter					
Air to Cloth Ratio (net)				ft/min	
Number of Compartments					
Number of Bags per Compartments					
Efficiency				%	
% of Fly Ash Sold	N/A	N/A	N/A	%	
SO_2 Emissions					
Emissions Limit	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet	Wet	Wet		
Current Emissions	0.411	0.419	0.676	lb/hr	
				ton/yr	
				lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	N	N	N		

Black & Veatch AQCS Information Needs

Power Plant: Cane Run
Owner: Louisville Gas & Electric
Unit:
Project:

ID Fan Information (at Full Load):	**Unit X**	**Unit X**	**Unit X**		**Notes**
ID Fan Inlet Pressure	-9.11	-6.82	-9.84	in wg.	
ID Fan Discharge Pressure	8	7	8	in wg.	
ID Fan Inlet Temperature				F	
Oxygen Content of Flue Gas @ ID Fan Inlet				%	
ID Fan Motor Voltage (Rated)	4160	4160	4000	volts	
ID Fan Motor Amps (Operating)	104.23	194.37	146.11	A	
ID Fan Motor Amps (Rated)	157	211	265	A	
ID Fan Motor Power (Rated)	1250	3000	2000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1	1.15		
Chimney Information:					
Flue Liner Material	Pre-Krete	Hadite/Pre-krete	Hastalloy C276		
Flue Diameter	14'2"	15'6"	24'41/2"	ft	
Chimney Height	239	239	500	ft	
Number of Flues	1	1	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
Specific burner and overfire air ports arrangement (single wall, opposed fired, total number of burners, number of burner levels, number of overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Cane Run Owner: Louisville Gas & Electric
Unit Project:

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life	20	20	20	years	
Annual Capacity Factor (over life of study/plant)	65	65	65	%	
Contingency Margin (can be determined by B&V)				%	
Owner Indirects Cost Margin				%	
Interest During Construction				%	
Levelized Fixed Charge Rate or Capital Recovery Factor				%	
Present Worth Discount Rate	6.4	6.4	6.4	%	
Capital Escalation Rate	4%	4%	4%	%	
O&M Escalation Rate	3%	3%	3%	%	
Energy Cost (energy to run in-house equipment)				$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)				$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)				$/MBtu	
				$/ton	
Base Fuel Price				$/MBtu	
				$/ton	
Fuel Price Escalation Rate				%	
Water Cost				$/1,000 gal	
Limestone Cost	N/A	N/A	N/A	$/ton	
Lime Cost	$112.54	$112.54	$112.54	$/ton	Total cost $773,013.3
Ammonia Cost	N/A	N/A	N/A	$/ton	
Fully Loaded Labor Rate (per person)				$/year	
Fly Ash Sales	N/A	N/A	N/A	$/ton	
Bottom Ash Sales	N/A	N/A	N/A	$/ton	
FGD Byproduct Sales	N/A	N/A	N/A	$/ton	
Waste Disposal Cost					
Fly Ash	$2.73			$/ton	Values represent total O&M cost for 2009. Plant Total
Bottom Ash	$8.40			$/ton	Values represent total O&M cost for 2009. Plant total
Scrubber Waste	$3,469.00	$4,989.00	$8,734.00	000$	Values represent total O&M cost for 2009.

Mill Creek

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**		**Notes**
Carbon	64			%	
Hydrogen	4.5			%	
Sulfur	3.5			%	
Nitrogen	1.3			%	
Oxygen	4.62			%	
Chlorine	0.08			%	
Ash	12			%	
Moisture	10			%	
Total	100.00				
Higher Heating Value, Btu/lb (as received)	11471.82			Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ______________ Owner: ______________
Unit ______________ Project: ______________

Plant Size and Operation Data: (provide for each unit)	Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate	B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Tangential fired	Tangential fired	opposed wall	opposed wall		
Boiler Manufacturer	CE	CE	B&W	B&W		
Net MW Rating (specify plant or turbine MW) Winter ratings	303MW	303MW	397MW	492MW	MW	
Gross MW Rating Winter ratings	330MW	330MW	423MW	525MW	MW	
Net Unit Heat Rate	10639	10929	10602	10410	Btu/kWh	
Net Turbine Heat Rate					Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)					%	
Fly Ash/Bottom Ash Split	80/20	80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)	N	N	N	N		
In operation? (Y/N)						
Flue Gas Recirculation (if installed)					%	
Type of Air Heater	Air Preheater Co.	Air Preheater Co.	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)	Vertical Flow	Vertical Flow	Vertical Flow	Vertical Flow		
Design Pressure/Vacuum Rating for Steam Generator +/-					in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-					in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Honeywell	Honeywell	Honeywel	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	TC3000			Experion		
Neural Network Installed? (Y/N)	Y	Y	N	N		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	Neuco	Neuco				
Extra Capacity available in DCS?	minimal	minimal	minimal	minimal		
Historian Manufacturer	Honeywell	Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear						
Capacity of Spare Electrical Cubicles in Existing MCC's and LCUS's (SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)	N	N	N	N		
Operating Conditions						
Economizer Outlet Temperature	760	760	690	640	°F	
Economizer Outlet Pressure	-5	-5	-5	-5	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	5	5	5	5	%	
Economizer Outlet Gas Flow	1524804	1524804	1958726	2239453	acfm	
	2976508	2976508	4056287	4848440	lb/hr	
Air Heater Outlet Temperature	375	375	325	315	°F	
Air Heater Outlet Pressure	-10	-10	-18	-18	in wg.	
Particulate Control Equipment Outlet Temperature	375	375	325	315	°F	
Particulate Control Equipment Outlet Pressure	-14	-14	-23	-21	in wg.	
FGD Outlet Temperature (if applicable)	133	133	130	130	°F	
FGD Outlet Pressure (if applicable)	1	1	1	1	in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

NOx Emissions	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**		**Notes**
Emissions Limit			0.7	0.7	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA etc.	LNB/OFA	LNB/OFA	LNB/SCR	LNB/SCR		
Current NOx Reduction with existing controls			90%	90%	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)			Anhydrous	Anhydrous		
Reagent Cost			500	500	$/ton	
Current Emissions	0.32	0.32	0.05	0.05	lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit	0.115	0.115	0.105	0.105	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold Side ESP	Cold Side ESP	Cold Side ESP	Cold Side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet	4	4	4	4	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	4	4	4	4	%	
Current Emissions	0.36	0.48	0.05	0.04	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	Y	Y	Y	Y		Very minimal at this point in time
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	1.2	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet FGD	Wet FGD	Wet FDG	Wet FGD		
Current Emissions	0.47	0.47	0.58	0.47	lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

ID Fan Information (at Full Load):	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**		**Notes**
ID Fan Inlet Pressure	-16	-16.5	-22	-23	in wg.	
ID Fan Discharge Pressure	-2	-1			in wg.	
ID Fan Inlet Temperature	340	340	330	330	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	4	4	4	4	%	
ID Fan Motor Voltage (Rated)	4160	4160	4160	4160	volts	
ID Fan Motor Amps (Operating)	275	275	920	1115	A	
ID Fan Motor Amps (Rated)	320	320	1176		A	
ID Fan Motor Power (Rated)	2500	2500	9000	9500	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1	1.15		

Chimney Information:						
Flue Liner Material	C276	C276	C276	C276		
Flue Diameter	15' 6"	15' 6"	19' 6"	19' 6"	ft	top of liner
Chimney Height	623	623	630	630	ft	
Number of Flues	1	1	1	1		1&2 share a common stack

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ____________________ Owner: ________________________________

Unit ____________________ Project: ________________________________

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Trimble County

Black & Veatch AQCS Information Needs

Power Plant: Trimble
Unit TC1 and TC2
Owner:
Project:

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**		**Notes**
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium %
Arsenic %
Mercury % or ppm
Other LOI %
Natural gas firing capability (if any at all)
Natural gas line (into the station) capacity (if applicable)
Current Lost on Ignition (LOI)
Start-up Fuel
Ash Fusion Temperature
Initial Deformation °F
Softening °F
Hemispherical °F
Hardgrove Grindability Index

Black & Veatch AQCS Information Needs

Power Plant: Trimble
Unit TC1 and TC2

Owner:
Project:

Plant Size and Operation Data: (provide for each unit)	**Unit 1**	**Unit 2**	**Unit X**	**Unit X**		**Notes**
Maximum (Design) Fuel Burn Rate	B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Tangential	Wallfired				
Boiler Manufacturer	Combustion Engineering	Doosan				
Net MW Rating (specify plant or turbine MW)	turbine 512	760			MW	
Gross MW Rating	547	509			MW	
Net Unit Heat Rate	10372	8662 guarentteed			Btu/kWh	
Net Turbine Heat Rate	gross 8362.53	7066 turbine guarenteed			Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)	NA	0.068 lb/MMBtu less than this at Econ outlet			%	
Fly Ash/Bottom Ash Split	80/20	80/20			%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)	N	N				
In operation? (Y/N)	N	NA				
Flue Gas Recirculation (if installed)	NA	NA			%	
Type of Air Heater	Regenerative	Regenerative				
Air Heater Configuration (horizontal or vertical flow or shaft)	Vertical 2 layer	Vertical 2 layer				
Design Pressure/Vacuum Rating for Steam Generator +/-	26.5	24/35 +/- 24 on continuous +/-35 on transient basis			in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-	42 at 100%	25/-6 +/-35 for DESP, PJFF +25/-6			in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Emerson	Emerson				
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	Ovation	Ovation				
Neural Network Installed? (Y/N)	N	N				
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	N/A	N/A				
Extra Capacity available in DCS?	Y	Y				
Historian Manufacturer	Emerson	Emerson				
Additional Controls from DCS or local PLC w/tie-in	Y	Y				
Transformer Rating for Intermediate Voltage Switchgear	100.8 MVA? Need better definintion					
(SUS's) and Ratings of Equipment in These Cubicles	NA					
Auxiliary Electric Limited (Y/N)	N					
Operating Conditions						
Economizer Outlet Temperature	700	586			°F	
Economizer Outlet Pressure	-6				in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	3	3.2/8.15 25%			%	
Economizer Outlet Gas Flow	N/A	3200333			acfm	
	N/A				lb/hr	
Air Heater Outlet Temperature	600	324			°F	
Air Heater Outlet Pressure	diff 6.5				in wg.	
Particulate Control Equipment Outlet Temperature	N/A	313			°F	
Particulate Control Equipment Outlet Pressure	-0.3				in wg.	
FGD Outlet Temperature (if applicable)	130	12.9 diff			°F	
FGD Outlet Pressure (if applicable)					in wg.	stack draft

Black & Veatch AQCS Information Needs

Power Plant: Trimble
Unit: TC1 and TC2
Owner:
Project:

NOx Emissions	**Unit 1**	**Unit 2**	**Unit X**	**Unit X**		**Notes**
Emissions Limit					lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.						
Current NOx Reduction with existing controls					%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)						
Reagent Cost					$/ton	
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF						
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions					lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section						
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)						
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Trimble
Unit TC1 and TC2

Owner:
Project:

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-0.3	-23.08			in wg.	
ID Fan Discharge Pressure	-0.3	15.77			in wg.	
ID Fan Inlet Temperature	300	313			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3-6%	4.2-9.2			%	
ID Fan Motor Voltage (Rated)	6600	13200			volts	
ID Fan Motor Amps (Operating)	535	NA			A	
ID Fan Motor Amps (Rated)	740	790			A	
ID Fan Motor Power (Rated)	9000	20241			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15				

Chimney Information:						
Flue Liner Material	FRP	FRP				
Flue Diameter	18'	18' & 10'			ft	
Chimney Height	754'	754'			ft	
Number of Flues	1	2				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Trimble
Unit TC1 and TC2
Owner:
Project:

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Green River

Black & Veatch AQCS Information Needs

Power Plant: Green River
Owner:
Unit
Project:

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	**Typical**	**Minimum**	**Maximum**		**Notes**
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium %
Arsenic %
Mercury % or ppm
Other LOI %
Natural gas firing capability (if any at all)
Natural gas line (into the station) capacity (if applicable)
Current Lost on Ignition (LOI)
Start-up Fuel

Ash Fusion Temperature
Initial Deformation °F
Softening °F
Hemispherical °F
Hardgrove Grindability Index

Black & Veatch AQCS Information Needs

Power Plant: Green River
Unit
Owner:
Project:

Plant Size and Operation Data: (provide for each unit)		**Unit 3**	**Unit 4**	**Unit X**	**Unit X**		**Notes**
Maximum (Design) Fuel Burn Rate		880	1.2			MBtu/hr	Original Design
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall Fired	Wall Fired				
Boiler Manufacturer		B&W	B&W				
Net MW Rating (specify plant or turbine MW)		71	102			MW	
Gross MW Rating		75	109			MW	
Net Unit Heat Rate		11942	11278			Btu/kWh	
Net Turbine Heat Rate						Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		Unknown	Unknown			%	
Fly Ash/Bottom Ash Split		80/20	80/20			%	
Flue Gas Recirculation (FGR)		NA	NA				
Installed? (Y/N)							
In operation? (Y/N)		NA	NA				
Flue Gas Recirculation (if installed)		NA	NA			%	
Type of Air Heater		Tubular	Lungstrom				
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical	Vertical				
Design Pressure/Vacuum Rating for Steam Generator	+/-	-18	-13.3			in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	-18	-13.3			in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Honeywell	Honeywell				
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Experion	Experion				
Neural Network Installed? (Y/N)		N	N				
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		NA	NA				
Extra Capacity available in DCS?		Y	Y				
Historian Manufacturer		Honeywell	Honeywell				
Additional Controls from DCS or local PLC w/tie-in		Y Rockwell	Y Rockwell				
Transformer Rating for Intermediate Voltage Switchgear		7.5 MVA	9.375 MVA				
(SUS's) and Ratings of Equipment in These Cubicles		N/A	N/A				
Auxiliary Electric Limited (Y/N)		N	N				
Operating Conditions							
Economizer Outlet Temperature		475	610			°F	
Economizer Outlet Pressure		-5	-6			in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		25%	25%			%	
Economizer Outlet Gas Flow						acfm	
		510	687			Klb/hr	
Air Heater Outlet Temperature		243	363			°F	
Air Heater Outlet Pressure		-9	-135			in wg.	
Particulate Control Equipment Outlet Temperature		230	600			°F	
Particulate Control Equipment Outlet Pressure		-11	-8.1			in wg.	
FGD Outlet Temperature (if applicable)		NA	NA			°F	
FGD Outlet Pressure (if applicable)		NA	NA			in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

NOx Emissions	Unit 3	Unit 4	Unit X	Unit X		Notes
Emissions Limit	0.46	0.5			lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB				
Current NOx Reduction with existing controls	NA	NA			%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	NA	NA				
Reagent Cost	NA	NA			$/ton	
Current Emissions					lb/hr	
					ton/yr	
	0.398	0.384			lb/MBtu	
Particulate Emissions						
Emissions Limit	0.29	0.14			lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side	Hot side				
Oxygen Content of Flue Gas @ Air Heater Outlet	~5%	~5%			%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	~5%	~5%			%	
Current Emissions	Compliance	Compliance			lb/MBtu	Indirectly measured by Opacity
Fly Ash Sold (Y/N) - See Economic Section	N	N				
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type	Weighted Wire	Weighted Wire				
Supplier	Buell	Buell				
Efficiency	98.50%	99%			%	
No. of Electrical Sections	6	7				
% of Fly Ash Sold	0	0			%	
Fabric Filter						
Air to Cloth Ratio (net)	NA	NA			ft/min	
Number of Compartments	NA	NA				
Number of Bags per Compartments	NA	NA				
Efficiency	NA	NA			%	
% of Fly Ash Sold	NA	NA			%	
SO_2 Emissions						
Emissions Limit	4.57	4.57			lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	NA	NA				
Current Emissions					lb/hr	
	5448	9276			ton/yr	2009 data
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Green River
Unit
Owner:
Project:

ID Fan Information (at Full Load):	Unit 3	Unit 4	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-7	-15.5			in wg.	
ID Fan Discharge Pressure	0	-0.24			in wg.	
ID Fan Inlet Temperature	230	365			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	~5%	~5%			%	
ID Fan Motor Voltage (Rated)	2300	2300			volts	
ID Fan Motor Amps (Operating)	105	230			A	
ID Fan Motor Amps (Rated)	98.3	224			A	
ID Fan Motor Power (Rated)	450	1000			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1				
Chimney Information:						
Flue Liner Material	Brick	Brick				
Flue Diameter	12	11			ft	
Chimney Height	198	247			ft	
Number of Flues	1	1				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Green River

Unit

Owner:

Project:

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Appendix C
Project Design Memorandum (Design Basis)

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	EW Brown			Ghent				Cane Run			Mill Creek				Trimble County		Green River		Reference
	1	2	3	1	2	3	4	4	5	6	1	2	3	4	1	2	3	4	
Ultimate Coal analysis, wet basis																			
Carbon, %	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	65.41	65.41	Data from E-ON
Hydrogen, %	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.46	4.46	Data from E-ON
Sulfur, %	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	2.60	2.60	Data from E-ON
Nitrogen, %	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.34	1.34	Data from E-ON
Chlorine, %	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	0.00	0.00	0.00	0.00	0.00	Data from E-ON
Oxygen, %	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.69	6.69	Data from E-ON
Ash, %	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	Data from E-ON
Moisture, %	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	10.50	10.50	Data from E-ON
Higher Heating Value, Btu/lb	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,600	11,600	Data from E-ON
Trace Metal Analysis, ppm																			
Antimony (Sb)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.07	1.07	Data from E-ON
Arsenic (As)	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	10.00	10.00	Data from E-ON
Barium (Ba)	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	49.00	49.00	Data from E-ON
Cadmium (Cd)	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.30	0.30	Data from E-ON
Chlorine (Cl)	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1845.00	1845.00	Data from E-ON
Chromium (Cr)	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	17.00	17.00	Data from E-ON
Fluorine (F)	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	71.00	71.00	Data from E-ON
Lead (Pb)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	Data from E-ON
Magnesium (Mg)	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	509.00	509.00	Data from E-ON
Mercury (Hg)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.10	0.10	Data from E-ON
Nickel (Ni)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	14.00	14.00	Data from E-ON
Selenium (Se)	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	1.93	1.93	Data from E-ON
Strontium (Sr)	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	30.00	30.00	Data from E-ON
Vanadium (V)	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Data from E-ON
Zinc (Zn)	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	50.00	50.00	Data from E-ON
Ash Analysis, % by mass																			
Alumina (Al2O3)	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	19.45	19.45	Data from E-ON
Barium Oxide (BaO)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	Data from E-ON
Lime (CaO)	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.89	2.89	Data from E-ON
Iron Oxide (Fe2O3)	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	19.90	19.90	Data from E-ON
Magnesia (MgO)	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	Data from E-ON
Manganese Oxide (MnO)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	Data from E-ON
Phosphorous Pentoxide (P2O5)	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.21	0.21	Data from E-ON
Potassium Oxide (K2O)	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.41	2.41	Data from E-ON
Silica (SiO2)	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	49.65	49.65	Data from E-ON
Sodium Oxide (Na2O)	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.77	0.77	Data from E-ON
Strontium Oxide (SrO)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	Data from E-ON
Sulfur Trioxide (SO3)	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.47	2.47	Data from E-ON
Titania (TiO2)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.08	1.08	Data from E-ON
Undetermined	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	Data from E-ON
Unit Characteristics																			
Gross Turbine Generator Load, MW	110	180	457	541	517	523	526	168	181	261	330	330	423	525	547	760	75	109	Data from E-ON
Boiler Efficiency, % (HHV)	85.32	86.73	86.53	85.74	86.83	86.31	86.77	85.12	87.14	87.09	85.40	85.40	86.51	86.51	86.88	86.92	89.02	85.25	Data from E-ON
Boiler Heat Input, MBtu/hr (HHV)	999.80	1,665.50	4,120.43	5,369	4,327	5,496	5,473	1,603	1,757	2,589	3,224	3,311	4,209	5,122	5,310	6,583	848	1,150	Data from E-ON
Coal Flow Rate, lb/hr	89,268	148,705	367,895	479,375	386,339	490,714	468,661	143,125	156,875	231,161	287,857	295,625	375,804	457,321	474,107	587,768	73,103	99,138	Data from E-ON
Capacity Factor, %	44.00	62.00	57.00	81.00	71.00	78.00	77.00	60.00	62.00	54.00	68.00	70.00	75.00	75.00	85.00	87.00	26.00	32.00	Data from E-ON
Fly Ash Portion of Total Ash, %	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	Data from E-ON
Air Heater Leakage, %	10.0	10.0	10.0	10.0	10.0	10.0	10.0	16.7	17.0	7.8	10.0	10.0	10.0	10.0	10.0	6.0	6.8	6.8	Data from E-ON
Excess Air, %	34.352	18.258	16.848	18.258	21.926	21.926	20.433	20.00	20.00	20.00	20.00	20.00	20.00	20.00	18.258	19.700	25.000	25.000	Data from E-ON
Economizer Outlet Conditions																			
Flue Gas Temperature, F	650	730	730	729	610	731	791	580	630	617	760	760	690	640	700	586	475	610	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-8.0	-3.7	-5.0	-3.2	-5.1	-5.1	-4.5	-4.0	-3.0	-4.0	-5.0	-5.0	-5.0	-5.0	-6.0	-6.0	-5.0	-6.0	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,090,927	1,615,221	3,952,267	5,206,933	4,316,060	5,482,104	5,397,559	1,575,668	1,727,042	2,544,856	3,169,029	3,254,545	4,137,234	5,034,667	5,149,714	6,455,853	886,785	1,202,598	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	509,072	796,739	1,955,176	2,563,081	1,922,533	2,718,161	2,805,958	680,015	779,254	1,137,376	1,608,445	1,651,849	1,979,343	2,303,938	2,490,348	2,816,034	345,095	536,927	B&V Combustion Calculations
Uncontrolled Sulfur Dioxide Concentration, lb/MBtu	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	6.00	6.00	6.00	4.48	4.48	= % Sulfur in Coal x 20,000 / HHV
Uncontrolled Sulfur Dioxide Mass Flow Rate, lb/hr	5,993	9,983	24,697	32,161	25,936	32,942	32,805	9,608	10,531	15,516	19,324	19,846	25,228	30,701	31,828	39,458	3,798	5,150	B&V Combustion Calculations
Uncontrolled PM Concentration, lb/MBtu	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	6.334	6.334	B&V Combustion Calculations
Uncontrolled PM Mass Flow Rate, lb/hr	8,744	14,566	36,037	46,957	37,844	48,068	47,867	14,020	15,367	22,643	28,197	28,958	36,812	44,797	46,441	57,575	5,371	7,284	= Uncontrolled PM (lb/MBtu) x Heat Input (MBtu/hr)
Uncontrolled Mercury Concentration, lb/TBtu	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	8.62	8.62	= Hg in Coal (ppm) x Coal Flow Rate (lb/hr) / Heat Input (MBtu/hr)
Uncontrolled HCl Mass Flow Rate, lb/hr	147	244.63	605.21	789	636	807	804	235	258	380	474	486	618	752	780	967	139	188	= HCl in Coal (ppm) / 1,000,000 x Coal Flow Rate (lb/hr) x MW of HCl / MW of Cl
Uncontrolled HCl Concentration, lb/MBtu	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	= HCl Flowrate (lb/hr) / Heat Input (MBtu/hr)
Hot-Side ESP Outlet Conditions	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**				**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**	**No Hot-side ESP. Unit has a Cold-side ESP**		
Flue Gas Temperature, F					605	708	770											600	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.					-10.80	-10.90	-10.8											-8.1	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr					4,531,863	5,756,209	5,667,437											1,262,728	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm					2,041,027	2,843,960	2,947,083											562,236	B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu					0.0565	0.0451	0.0248											0.08	B&V Combustion Calculations
Controlled PM Mass Flow Rate, lb/hr					244	248	135.73											92	= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %					99.35	99.48	99.72											98.74	= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
SCR Outlet Conditions	**No SCR**	**No SCR**	**New SCR Planned for 2012**		**No SCR**			**No SCR**	**No SCR**	**No SCR**	**No SCR**	**No SCR**					**No SCR**	**No SCR**	
Flue Gas Temperature, F				729		708	770						690	640	700	586			B&V Combustion Calculations
Flue Gas Pressure, in. w.g.				-13.2		-20.90	-20.8						-13.0	-13.0	-16.0	-11.0			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr				5,311,071		5,871,333	5,780,786						4,219,979	5,135,360	5,252,708	6,584,970			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm				2,682,371		2,977,658	3,085,629						2,061,162	2,399,175	2,606,716	2,910,365			B&V Combustion Calculations
Controlled NOx Concentration, lb/MBtu				0.0639		0.0479	0.0627						0.0584	0.0589	0.076	0.076			Data from E-ON
Controlled NOx Mass Flow Rate, lb/hr				343		263	343						246	302	404	500			= Controlled NOx (lb/MBtu) x Heat Input (MBtu/hr)
Air Heater Outlet Conditions																			
Flue Gas Temperature, F	350	330	340	361	309	322	309	369	299	318	375	375	330	330	320	324	243	363	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-14.00	-8.00	-18.00	-22.4	-18.60	-36.10	-29.4	-8.0	-6.0	-8.0	-10.0	-10.0	-18.0	-18.0	-22.5	-16.0	-9.0	-13.5	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,200,020	1,776,743	4,347,494	5,842,179	4,985,049	6,458,467	6,358,865	1,839,262	2,021,310	2,744,081	3,485,932	3,580,000	4,641,976	5,648,896	5,777,979	6,980,068	947,426	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,851	589,646	1,498,187	2,091,568	1,657,754	2,288,309	2,175,592	641,787	642,552	896,674	1,229,416	1,262,592	1,581,582	1,924,653	1,965,750	2,345,528	280,496	473,593	B&V Combustion Calculations
Cold-Side ESP Outlet Conditions					**No Cold-side ESP. Unit has a Hot-side ESP**	**No Cold-side ESP. Unit has a Hot-side ESP**	**No Cold-side ESP. Unit has a Hot-side ESP**											**No Cold-side ESP. Unit has a Hot-side ESP**	
Flue Gas Temperature, F	340	320	330	358				369	299	318	340	340	330	330	320	324	230		B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-18.00	-12.00	-19.00	-25.7				-9.1	-6.8	-9.8	-14.0	-14.0	-23.0	-21.0	-25.5	-18.0	-11.0		B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288				1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797		B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	436,197	618,296	1,559,510	2,209,920				676,568	676,855	947,034	1,250,977	1,284,735	1,684,442	2,039,199	2,082,968	2,502,995	290,916		B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu	0.241	0.1	0.1	0.023				0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.31	0.063		Data from E-ON
Controlled PM Mass Flow Rate, lb/hr	241	166.55	412.04	123				66	60	62	124	147	218	181	90	2041	53		= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %	97.24	98.86	98.86	99.74				99.53	99.61	99.73	99.56	99.49	99.41	99.60	99.81	96.46	99.01		= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
Fabric Filter Outlet Conditions	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**	**No Fabric Filter**		**No Fabric Filter**	**No Fabric Filter**	
Flue Gas Temperature, F																313			B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																-23.1			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr																7,398,872			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																2,500,664			B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu																0.015			Data from E-ON
Controlled PM Mass Flow Rate, lb/hr																99			= Controlled PM from fabric Filter (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %																95.16			= { 1- FF Controlled PM (lb/MBtu) / ESP Controlled PM (lb/MBtu) } x 100
ID Fan Outlet Conditions																			
Flue Gas Temperature, F	356.05	332.17	346.44	376.94	325.52	346.34	333.60	379.03	306.39	327.81	354.85	355.15	348.83	348.83	340.08	334.60	235.91	371.55	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	10.00	10.00	10.00	6.10	11.40	5.90	14.60	8.00	7.00	8.00	10.00	10.00	10.00	10.00	10.00	15.77	1.00	1.00	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288	4,985,049	6,458,467	6,358,865	1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,059	594,805	1,481,211	2,086,965	1,571,913	2,119,437	2,010,799	656,526	660,654	917,824	1,200,841	1,233,697	1,588,066	1,932,543	1,954,644	2,334,113	284,775	461,503	B&V Combustion Calculations

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	**EW Brown**			**Ghent**				**Cane Run**			**Mill Creek**				**Trimble County**		**Green River**		**Reference**
	1	**2**	**3**	**1**	**2**	**3**	**4**	**4**	**5**	**6**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	
Scrubber Outlet Conditions	(For 3 units combined to a common/shared scrubber)																		
Flue Gas Temperature, F	129.64			131.74	128.04	129.28	128.50	131.19	125.96	128.80	130.30	130.32	129.60	129.60	129.24	129.43	**No Scrubber**	**No Scrubber**	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	2.00			1.70	1.50	2.00	1.60	2.00	2.00	2.00	1.00	1.00	1.00	1.00	2.00	6.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	8,136,097			6,534,149	5,252,980	6,834,132	6,711,801	2,056,206	2,226,116	3,036,144	3,879,298	3,984,228	5,157.618	6,277,442	6,413,722	7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	2,029,766			1,643,977	1,306,064	1,705,743	1,671,656	517,157	550,120	754,452	972,502	998,878	1,291.025	1,571,359	1,598,535	1,327,087			B&V Combustion Calculations
Controlled Sulfur Dioxide Mass Flow Rate, lb/hr	679			805	865	824	821	659	736	1,750	1,515	1,556	2,441	2,407	441	546			B&V Combustion Calculations
Controlled Sulfur Dioxide Concentration, lb/MBtu	0.10			0.150	0.200	0.150	0.150	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083			= Controlled SO_2 (lb/hr) / Heat Input (MBtu/hr)
Sulfur Dioxide Removal Efficiency, %	98.33			97.50	96.67	97.50	97.50	93.15	93.02	88.73	92.17	92.17	90.33	92.17	98.62	98.62			= { 1- Controlled SO_2 (lb/MBtu) / Uncontrolled SO_2 (lb/MBtu) } x 100
Wet ESP Outlet Conditions	**No WESP**			**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**	**No WESP**		**No WESP**	**No WESP**	
Flue Gas Temperature, F																129.43			B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																2.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr																7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																1,945,943			B&V Combustion Calculations
Stack Outlet Emissions[1]																			
Sulfur Dioxide Emission Concentration, lb/MBtu	0.10	0.10	0.10	0.15	0.20	0.15	0.15	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083	4.48	4.48	Data from E-ON
Sulfur Dioxide Emission Rate, lb/hr	100	167	412	805	865	824	821	659	736	1,750	1,515	1.556	2,441	2,407	441	546	3,798	5,150	= SO_2 Emission (lb/MBtu) x Heat Input (MBtu/hr)
PM Emission Concentration, lb/MBtu	0.241	0.1	0.1	0.023	0.0565	0.0451	0.0248	0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.015	0.063	0.08	Data from E-ON
PM Emission Rate, lb/hr	241	167	412	123	244	248	136	66	60	62	124	147	218	181	90	99	53	92	= PM Emission (lb/MBtu) x Heat Input (MBtu/hr)
NOx Emission Concentration, lb/MBtu	0.4463	0.4374	0.3319	0.0639	0.276	0.0479	0.0627	0.3394	0.3843	0.272	0.3169	0.3139	0.0584	0.0589	0.076	0.076	0.4011	0.3864	Data from E-ON
NOx Emission Rate, lb/hr	446	728	1,368	343	1,194	263	343	544	675	704	1,022	1,039	246	302	404	500	340	444	= NOx Emission (lb/MBtu) x Heat Input (MBtu/hr)
Hg Emission Concentration, lb/TBtu	5.0	5.0	5.0	2.0	3.5	2.0	2.0	3.5	3.5	3.5	3.0	3.0	2.5	2.5	1.2	1.0	5.5	5.5	Data from E-ON
Hg Emission Rate, lb/hr	5.00E-03	8.33E-03	2.06E-02	1.07E-02	1.51E-02	1.10E-02	1.09E-02	5.61E-03	6.15E-03	9.06E-03	9.67E-03	9.93E-03	1.05E-02	1.28E-02	6.37E-03	6.58E-03	4.66E-03	6.33E-03	= Hg Emission (lb/TBtu) x Heat Input (MBtu/hr) / 1,000,000
HCl Emission Concentration, lb/MBtu	0.002	0.002	0.002	0.0015	0.0017	0.0015	0.0015	0.00095	0.00095	0.00095	0.0015	0.0015	0.0015	0.0015	0.00085	0.00085	0.017	0.017	Data from E-ON
HCl Emission Rate, lb/hr	2	3	8	8	7	8	8	2	2	2	5	5	6	8	5	6	14	20	= HCl Emission (lb/MBtu) x Heat Input (MBtu/hr)
CO Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
CO Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
Dioxin/Furan Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known
Dioxin/Furan Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known

Notes:

1. Current Outlet Emissions as noted in E-ON Matrix

Revision History:

Rev	Date	Description
0	5/21/2010	Initial Issue
1	6/1/2010	Final Issue

Appendix D
Air Quality Control Technology Descriptions

CONTROL TECHNOLOGY DESCRIPTIONS

NO_x Reduction Technologies

Low NO_x Burners (LNB)

The new-generation LNB have better NO_x removal performance than the first-generation LNB and are a fundamental component of the boiler design. The term ultra-low NO_x burners applies only to gas fired applications and does not apply to coal fired boilers.

LNB control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce NO_x by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This minimizes the reaction time at oxygen-rich, high-temperature conditions. Conventional burners, however, typically mix the secondary air with the primary air/fuel stream immediately following injection into the furnace, creating a high intensity combustion process.

Wall mounted LNB are typically a multiple-register (damper) type with two separate secondary airflow paths through the burner and into the furnace. Common features include dedicated total secondary airflow control dampers and separate dedicated dampers or vanes to control the flow and spin of the individual secondary airflows through the burner. The vanes that control spin or flame shape are typically set during initial startup and then locked in place.

Control and balancing of the secondary air, primary air, and coal distribution among the burners is a basic requirement of all manufacturers. Typical allowable flow deviations from the mean are 10 percent for individual burner air and coal flows. This requirement may necessitate changes in operating procedures related to individual burner level turn down at part load. Conversely, additional control provisions and flow monitoring capability is required to preserve the option to operate with unbalanced firing at part load.

The basic NO_x reduction principles for LNB are to control and balance the fuel and air flow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high-temperature zones are not oxygen rich. Figure D-1 shows the low NOx burners

Low NO_X Burner Systems

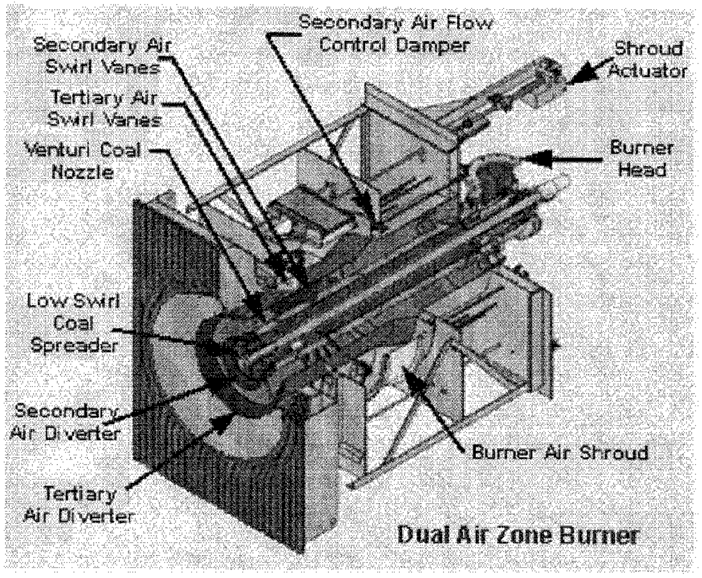


Figure D-1
Low NO_X Burners (Courtesy: DB Riley)

Overfire Air (OFA)

OFA is an air staging NO_x reduction technique that is based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the high temperature zone of the furnace. OFA can be used in conjunction with the LNB system. Unburned carbon and combustible materials may increase as a result of the addition of OFA because of the staging of the combustion process.

With the installation of an OFA system, the main combustion burners are operated at or near stoichiometric ratio to limit available oxygen, flame temperature, and NO_x formation. The remainder of the combustion air is then injected through the OFA ports to complete combustion. The quantity of OFA introduced is sufficient to increase the overall excess air in the boiler to 15 to 20 percent to ensure complete combustion and maintain flue gas flow through the convective sections of the boiler.

OFA systems reduce NO_X formation by creating a fuel rich combustion zone. The OFA is introduced above the main combustion zone (fuel is introduced in an oxygen-starved environment) where fuel burnout can be completed at a lower temperature with fewer volatile nitrogen-bearing combustion products.

The OFA ports will be designed to allow adequate mixing of the combustion air and flue gas and with sufficient temperatures and residence times to ensure complete combustion to achieve optimum NO_X reductions. The location of the OFA ports is critical in achieving optimum NO_X reductions without affecting unburned carbon losses. Figure D-2 shows the overfire air

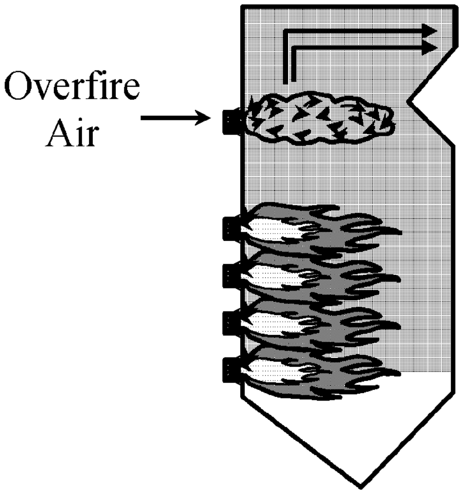


Figure D-2
Overfire Air System

Selective Noncatalytic Reduction System (SNCR)

Selective non-catalytic NO_X reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve NO_X reductions. SNCR systems can use either ammonia (Thermal $DeNO_X$) or urea (NO_XOUT) as reagents.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900° F. The NO_X reduction efficiency of an SNCR system decreases rapidly at temperatures outside this range. Injection of reagent below this temperature window results in excessive ammonia slip emissions. Injection of reagent above this temperature window results in increased NO_X emissions. A PC boiler operates at temperatures of between 2,500 and 3,000° F. Therefore, the optimum temperature window in a PC boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature range are very limited, further detracting from optimum SNCR performance. Finally, there is no provision for feedforward control of reagent injection, relying only on feedback control. This results in over injection of reagent and high ammonia slip emissions.

SNCR systems are less efficient NO_x reduction systems than SCR systems. In general, SNCR systems on large PC-fired boilers will be capable of only up to 50 percent NO_x reduction. Figure D-3 shows a schematic of SNCR system.

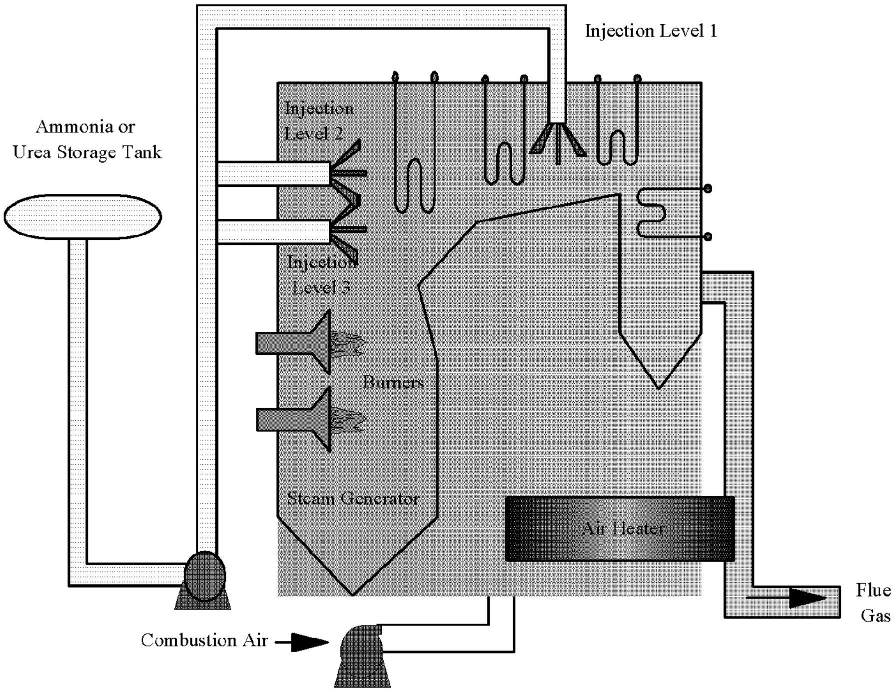


Figure D-3
Schematic of SNCR System with Multiple Injection Levels

Selective Catalytic Reduction System (SCR)

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_x into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_x-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_x levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_x available for removal. Essentially, as NO_x is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature is costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure D-4 shows a schematic diagram of SCR.

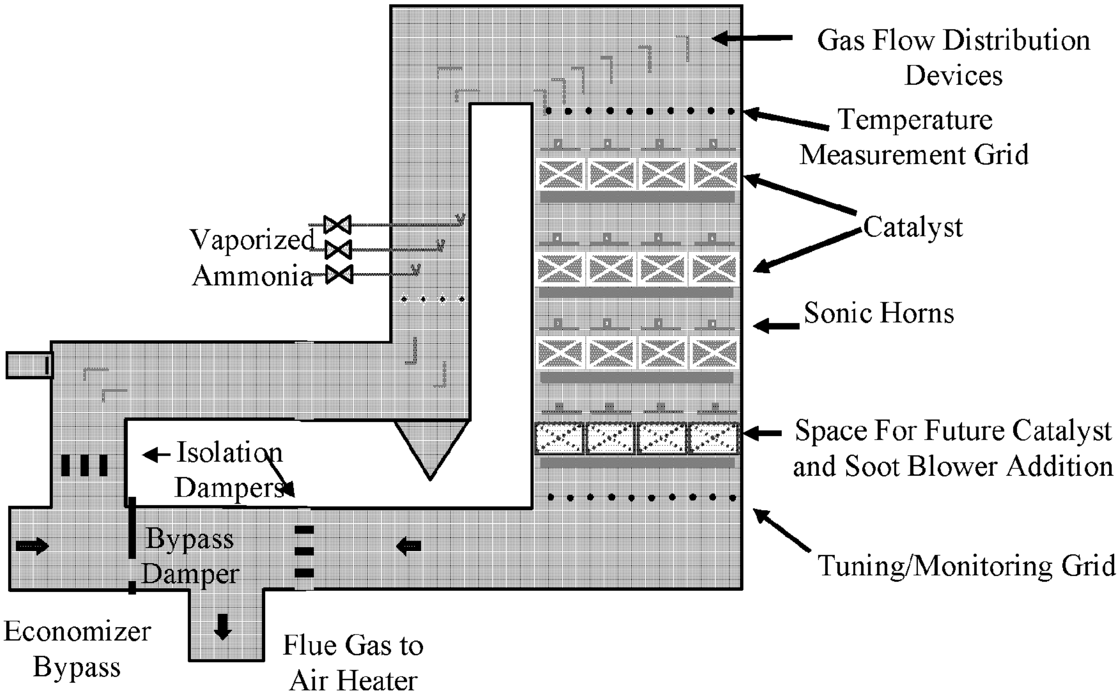


Figure D-4
Schematic Diagram of a Typical SCR Reactor

SNCR/SCR Hybrid System

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and potential for high NH_3 slip associated with SNCR systems with the high reduction potential and low NH_3 slip inherent with catalyst based SCR systems. The result is an NO_x reduction alternative that can meet initial NO_x reduction requirements but can be upgraded to meet higher reductions at a future date, if required. Typically, installation of an SCR system with a single layer of in-duct catalyst is capable of reducing NO_x emissions from 40 to 70 percent, depending on the amount of NH_3 slip from the SCR and the volume of the single layer of catalyst.

The SNCR component of the hybrid system is identical to the SNCR system, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would inject higher amounts of reagent into the flue gas. This increased reagent flow has a two-fold effect: NO_x reduction within the boiler is increased while NH_3 slip is also increased. The NH_3 that slips from the SNCR is then used as the reagent for the single layer of catalyst.

There are two design philosophies for using this excess NH_3 slip. The most conservative hybrid systems will use the catalyst simply as an NH_3 slip "scrubber" with some additional NO_x reduction. Similar to in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. While some NO_x reduction is achieved at the catalyst, the relatively small catalyst requirement of this design has the potential to fit all the catalyst in a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural adaptations.

The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of NH_3 slip, the catalyst volume, and the distribution of NH_3 to NO_x within the flue gas. Using NH_3 slip that is produced by the SNCR system is not a high efficiency method of introducing reagent, due to the low reagent utilization. Therefore, even though the reaction at the catalyst requires 1 ppm of NH_3 to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of NH_3 to generate 1 ppm of NH_3 at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the NH_3 distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the typical ductwork. If widening the ductwork cannot provide for adequate catalyst volume, then a separate reactor is required, which quickly negates the capital cost advantage of a hybrid system. Figure D-5 represents a schematic diagram of a typical SNCR/SCR Hybrid system.

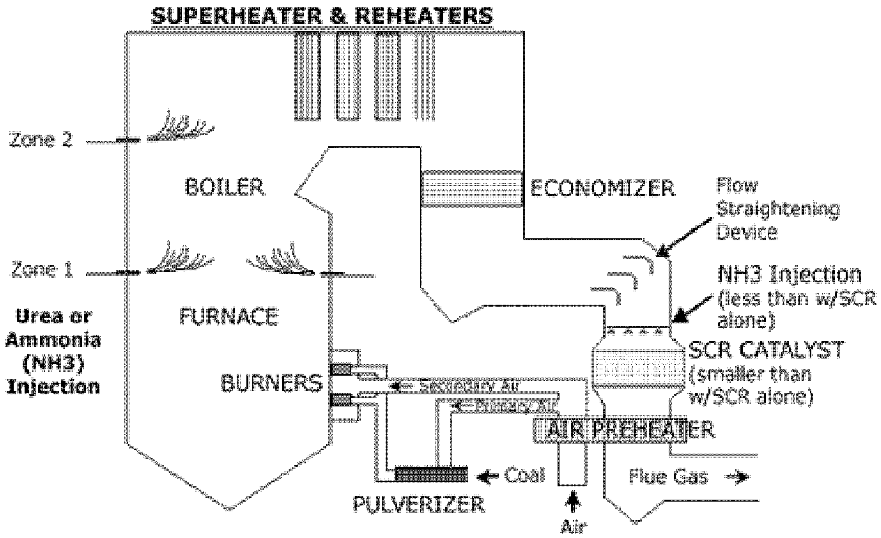


Figure D-5
Schematic Diagram of a Typical SNCR/SCR Hybrid System (Courtesy: Clean Environmental Protection Engineering Co. Ltd.)

SO_2 and HCl Reduction Technologies

Wet Flue Gas Desulfurization (FGD) System

Wet limestone-based FGD processes are frequently applied to pulverized coal fired boilers that burns medium-to-high sulfur eastern coals. All of the FGD systems installed in response to Phase I of the 1990 CAA were based on a wet FGD system using either lime or limestone as the reagent. Typically, the wet FGD processes on a pulverized coal facility are characterized by high efficiency (> 98 percent) and high reagent utilization (95 to 97 percent) when combined with a high sulfur fuel. The ability to realize high removal efficiencies on higher sulfur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes. It is well known that SO_2 removal efficiencies for wet FGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove SO_2 are faster if the inlet SO_2 concentration is higher. The absolute emissions level becomes a limiting factor due to a reduction in the chemical driving forces of the reactions that are occurring. Thus, the calculated removal efficiency of the various types of wet scrubbers declines as the fuel sulfur content decreases; this is the case for low sulfur western and PRB coals.

In a wet FGD system, the absorber module is located downstream of the induced draft (ID) fans (or booster ID fans, if required). Flue gas enters the module and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3 \bullet 1/2H_2O$ and $CaSO_4 \bullet 2H_2O$. SO_2 reacts with limestone reagent through the following overall reactions:

$$SO_2 + CaCO_3 + \frac{1}{2}H_2O \rightarrow CaSO_3 \bullet \frac{1}{2}H_2O + CO_2$$

$$SO_2 + CaCO_3 + 2H_2O + \frac{1}{2}O_2 \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

The flue gas leaving the absorber will be saturated with water, and the stack will have a visible moisture plume. Because of the chlorides present in the mist carry-over from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and the flue stack. Careful design of the stack is needed to prevent the “rainout” from condensation that occurs in the downstream ductwork and stack. These factors contribute to the relatively high capital costs of the wet FGD SO_2 control alternative.

The reaction products are typically dewatered by a combination of hydrocyclones and vacuum filters. The resulting filter cake is suitable for landfill disposal. In early lime- and limestone-based FGD processes, the byproduct solids were primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$), and the byproduct solids were mixed with fly ash (stabilization) or fly ash and lime (fixation) to produce a physically stable material. In the current generation of wet FGD systems, air is bubbled through the reaction tank (or in some cases, a separate vessel) to practically convert all of the $CaSO_3 \bullet 1/2H_2O$ into calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$), which is commonly known as gypsum. This step is termed “forced oxidation” and has been applied to both lime- and limestone-based FGD processes. Compared to calcium sulfite hemihydrate, gypsum has much superior dewatering and physical properties, and forced oxidized FGD systems tend to have few internal scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many FGD systems in the United States are using the forced-oxidation process to produce a commercial grade of gypsum that can be used in the production of portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinyl ester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The byproduct dewatering equipment is also relatively complex and expensive. These factors result in relatively higher initial capital costs. Wet FGD processes are also characterized by higher raw water usage than semi-dry FGD systems. This can be a significant disadvantage or even a fatal flaw in areas where raw water availability is in short supply.

A countercurrent spray tower has become one of the most widely used absorber types in wet limestone-based FGD service. Flue gas enters at the bottom of the absorber and flows upward. Slurry with 10 to 15 percent solids is sprayed downward from higher elevations in the absorber and is collected in a reaction tank at its base. The SO_2 in the flue gas is transferred from the flue gas to the recycle slurry. The hot flue gas is also cooled and saturated with water. Recycled slurry is pumped continuously from the reaction tank to the slurry spray headers. Each header has numerous individual spray nozzles that break the slurry flow into small droplets and distribute them evenly across the cross section of the absorber. Prior to leaving the absorber, the treated flue gas passes through a two-stage, chevron-type mist eliminator that removes entrained slurry droplets from the gas. The mist eliminator is periodically washed to keep it free of solids.

In the reaction tank, the SO_2 absorbed from the flue gas reacts with soluble calcium ions in the recycle slurry to form insoluble calcium sulfite and calcium sulfate solids. In forced-oxidization processes, air is bubbled through the slurry to convert all of the solids to calcium sulfate dihydrate (gypsum). A lime or limestone reagent slurry is added to the reaction tank to replace the calcium consumed.

To control the solids content of the recycle slurry, a portion of the slurry is discharged from the reaction tank to the byproduct dewatering equipment. Depending on the ultimate disposal of the byproduct solids, the dewatering equipment may include settling ponds, thickeners, hydrocyclones, vacuum filters, and centrifuges. The liquid that is separated from the byproduct solids slurry is stored in the reclaim water tank. Water in the reclaim water tank is returned to the absorber reaction tank as makeup water and used to prepare the reagent slurry.

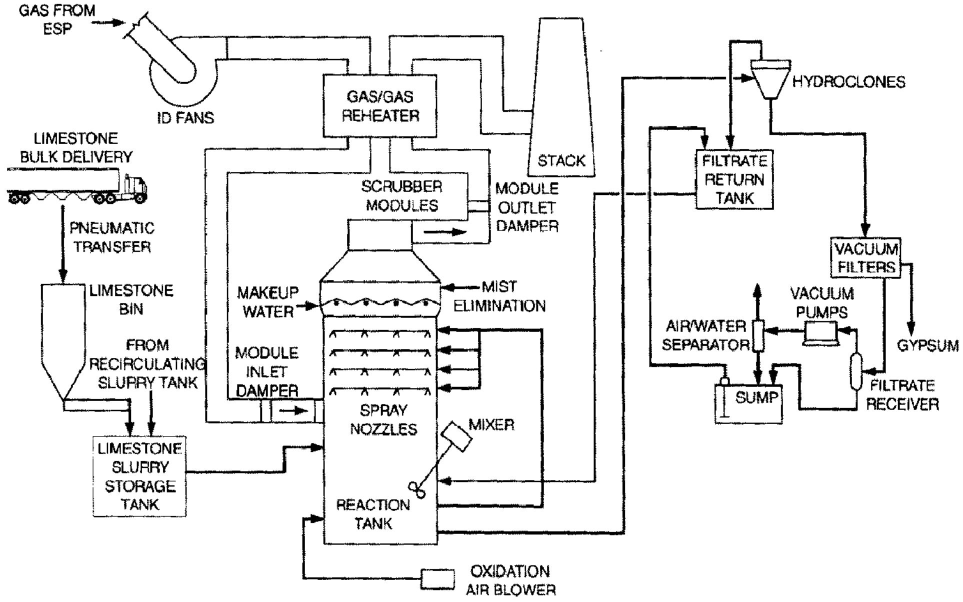


Figure D-6
Process Flow Diagram of FGD Process

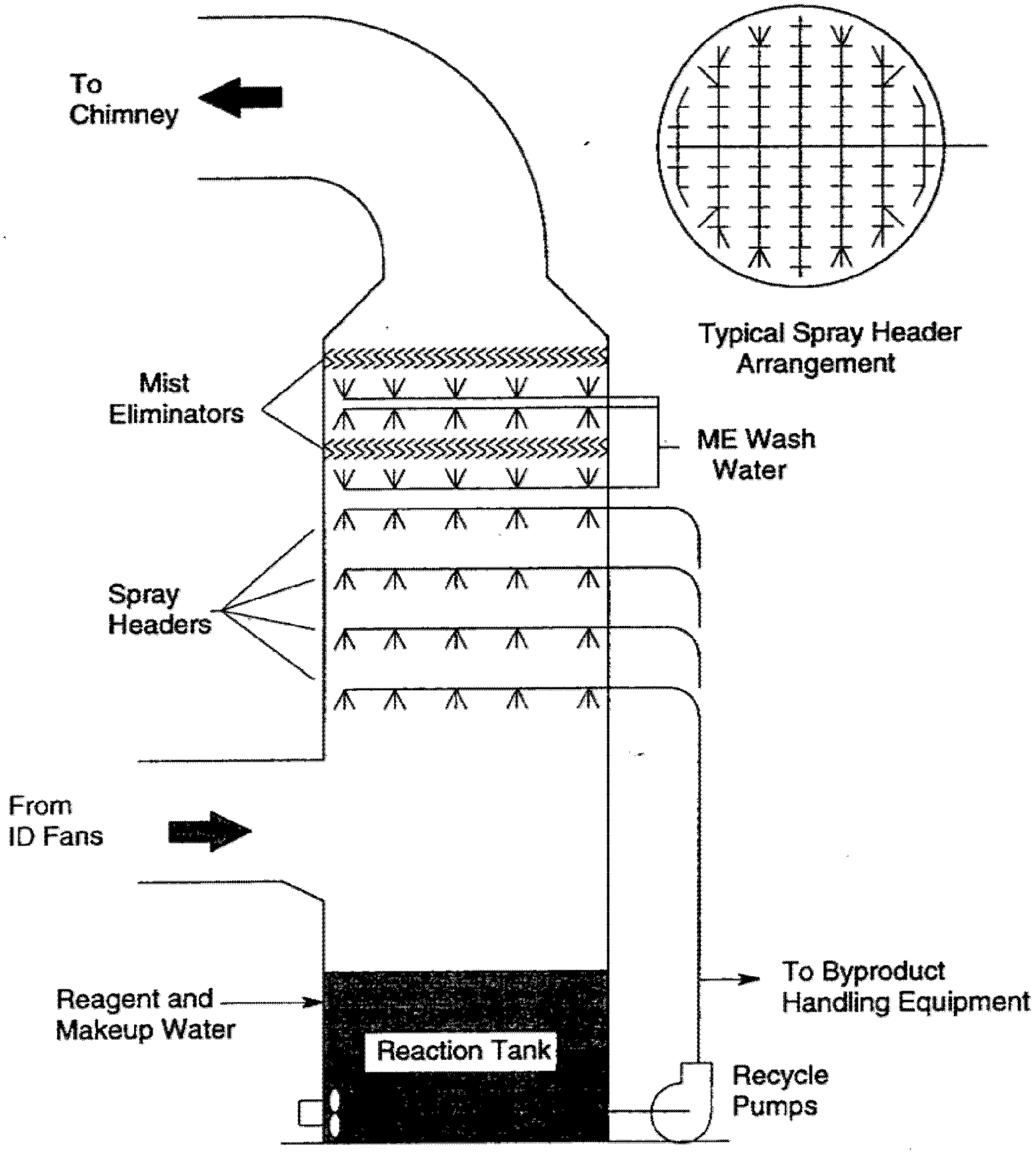


Figure D-7
Countercurrent Spray Tower FGD Process

Spray Dryer Absorber

Spray dryer absorber (SDA) FGD processes have been extensively used. US utilities have installed numerous SDA FGD systems on boilers using low sulfur fuels.

These installations, primarily located in the western United States, use either lignite or subbituminous coals such as PRB as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The SDA lime-based FGD system has an inherent removal efficiency limitation of 94 percent from inlet concentration.

The SDA FGD process uses calcium hydroxide [$Ca(OH)_2$] produced from the lime reagent as either a slurry or as a dry powder to the flue gas in a reactor designed to provide good gas-reagent contact. The SO_2 in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate ($CaSO_3\bullet 1/2H_2O$) and a smaller amount of calcium sulfate dihydrate ($CaSO_4\bullet 2H_2O$) through the following reactions:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3\bullet ½H_2O + ½H_2O$$
$$SO_2 + Ca(OH)_2 + ½O_2 \rightarrow CaSO_4\bullet 2H_2O$$

Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these SDA FGD processes compared to wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a particulate control device (either fabric filter or DESP). Fabric filters are preferred for most systems, because the additional contact of the flue gas with the particulate on the filter bags provides additional SO_2 removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system in order to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The SDA FGD processes offer benefits in addition to SO_2 removal, including the lack of a visible vapor plume and SO_3 removal. Because the SDA FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with SO_3 emissions are also reduced with the SDA scrubber. SO_3 is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. An increase in H_2SO_4

emissions will increase PM_{10} emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant SO_3 removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO_3 in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any SO_3 plume that may cause opacity in stacks. Similar type of SO_3 removal is not achievable with a wet scrubber.

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

In both cases, the atomizers are located in the roof of the absorber. Both rotary and two-fluid nozzles have been applied to this approach. The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The SO_2 in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

Some vendors base their designs on a single large rotary atomizer per absorber; others use up to three smaller rotary atomizers per absorber. Two-fluid atomizers are installed as an array of up to 16 nozzles per atomizer; all three approaches to spray atomizers have been successfully applied.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the solids collected is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

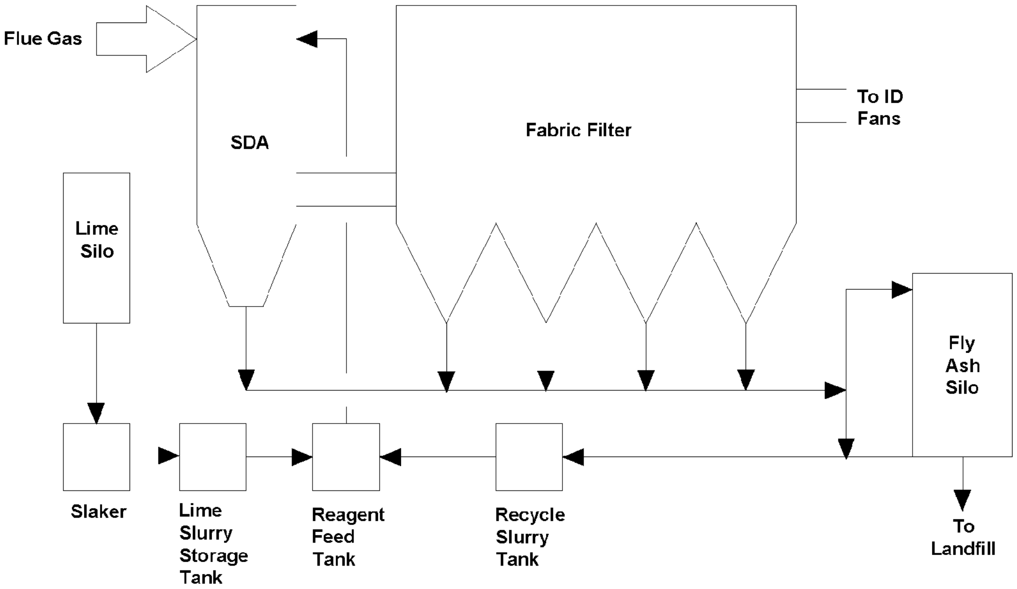


Figure D-8
SDA FGD Process

Circulating Dry Scrubber (CDS)

The CDS FGD process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module is a vertical solid/gas reactor between the unit's air heater and its particulate control device. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected cocurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the reagent to form predominately calcium sulfite. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or electrostatic precipitator [ESP]). Over 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2/reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device due to the recycling of the byproduct/fly ash mixture. For this reason, some CDS FGD system vendors prefer to use an ESP rather than a fabric filter. Most of the recycled material can be collected in the first field of an ESP with minimal effect on the overall ESP sizing. On the other hand, a fabric filter in this same service would require special design features to avoid reduced bag life associated with frequent bag cleaning. Figure D-9 provides an illustration of the CDS FGD system.

The CDS can be considered an acceptable FGD removal technology in some applications because of its ability to remove significant amounts of SO_2, the commercial status of the technology, and the use of conventional reagents. It has disadvantages relating to the downstream particulate load imposed on collectors but its implementation schedule and minimal impact on local communities adds to its acceptability.

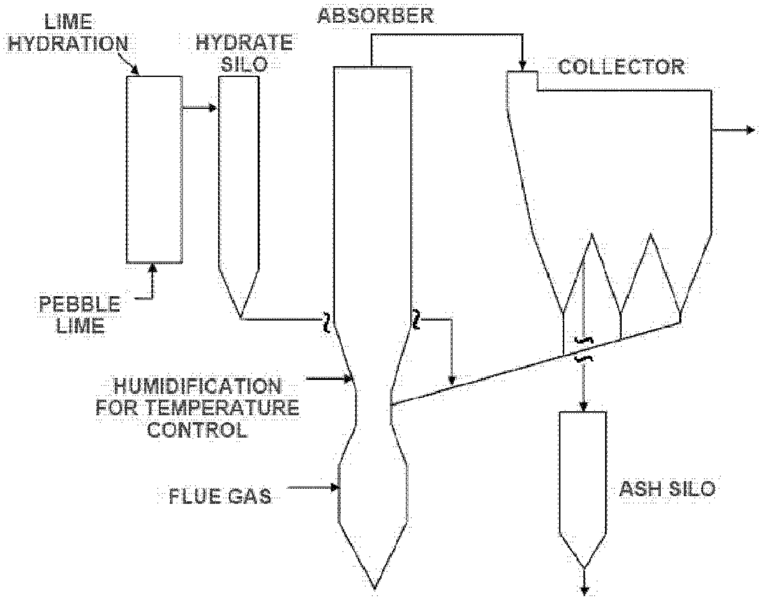


Figure D-9
Circulating Dry Scrubber System (Courtesy: Lurgi Lentjes North America)

Particulate Matter (PM) Reduction Technologies

Dry Electrostatic Precipitator (ESP)

ESPs are the most widely installed utility particulate matter (PM) removal technology. ESPs use transformer/rectifiers (TRs) to energize "discharge electrodes" and to produce a high voltage, direct current electrical field between the discharge electrodes and the grounded collecting plates. PM entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. This migration can be expressed in engineering terms as an empirically determined effective migration velocity, but takes place in a turbulent flow regime with the particulate entrained within the turbulent gas patterns. Thus, the charged particles are actually captured when the combined effect of electrical attraction and gas flow patterns moves the PM close enough for it to attach to the collecting surfaces. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically impacting or "rapping" the plates. The collected particulate matter drops into hoppers below the precipitator and is removed by the ash handling system. Some particulate is also re-entrained and either collected in subsequent electrical fields or emitted from the ESP. A graphic showing the sections of an ESP is shown on Figure D-10.

The required particulate removal efficiency, the expected electrical resistivity of the fly ash to be collected, and the expected electrical characteristics of the energization system determine the physical size of an ESP. Many parameters determine the ESP's capability for particulate collection including the following major items:

- The first parameter is the Specific Collection Area (SCA). ESP size is often measured in terms of SCA. SCA is defined as the total collecting area in square feet (ft^2) divided by the volumetric flue gas flow rate (1,000's of actual cubic feet per minute [acfm]).
- The treatment time of the flue gas within the electric collection fields of the ESP is an important aspect of particulate collection. High efficiency ESPs typically have treatment times between 7 and 20 seconds. Treatment time is becoming a major design parameter as lower particulate emissions are being mandated.
- Flue gas velocity, which is the speed at which the flue gas moves through the ESP, is important in the design and sizing of an ESP. Design gas velocities that range between 3 to 4 fps are common. The aspect ratio of the treatment length to the collection plate height is also important in the design and sizing of the ESP. As the aspect ratio increases, the re-entrainment losses from the ESP are minimized. Many existing ESPs have aspect ratios of approximately 0.8 to 1.2; newer ESPs, especially those meeting new particulate emission limits, have aspect ratios of approximately 1.2 to 2.0.
- The gas distribution for optimum particulate removal requires a uniform gas velocity throughout the entire ESP treatment volume, with minimal gas bypass around the discharge electrodes or collecting plates. If flue gas distribution is uneven, the particulate removal efficiency will decrease, and re-entrainment losses will increase in high velocity areas and reduce overall collection efficiency.
- Fly ash resistivity is a measure of how easily the ash or particulate acquires an electric charge. Typical coal fly ash resistivity values range from 1×10^8 ohm-cm to 1×10^{14} ohm-cm. The ideal resistivity range for electrostatic precipitation of fly ash is 5×10^9 to 5×10^{10} ohm-cm. Operating resistivity varies with flue gas moisture, SO_3 concentration, temperature, and ash chemical composition. As a result of fly ash resistivity being sensitive to these constituents, ESPs can be affected greatly by changes in fuel or operating conditions.

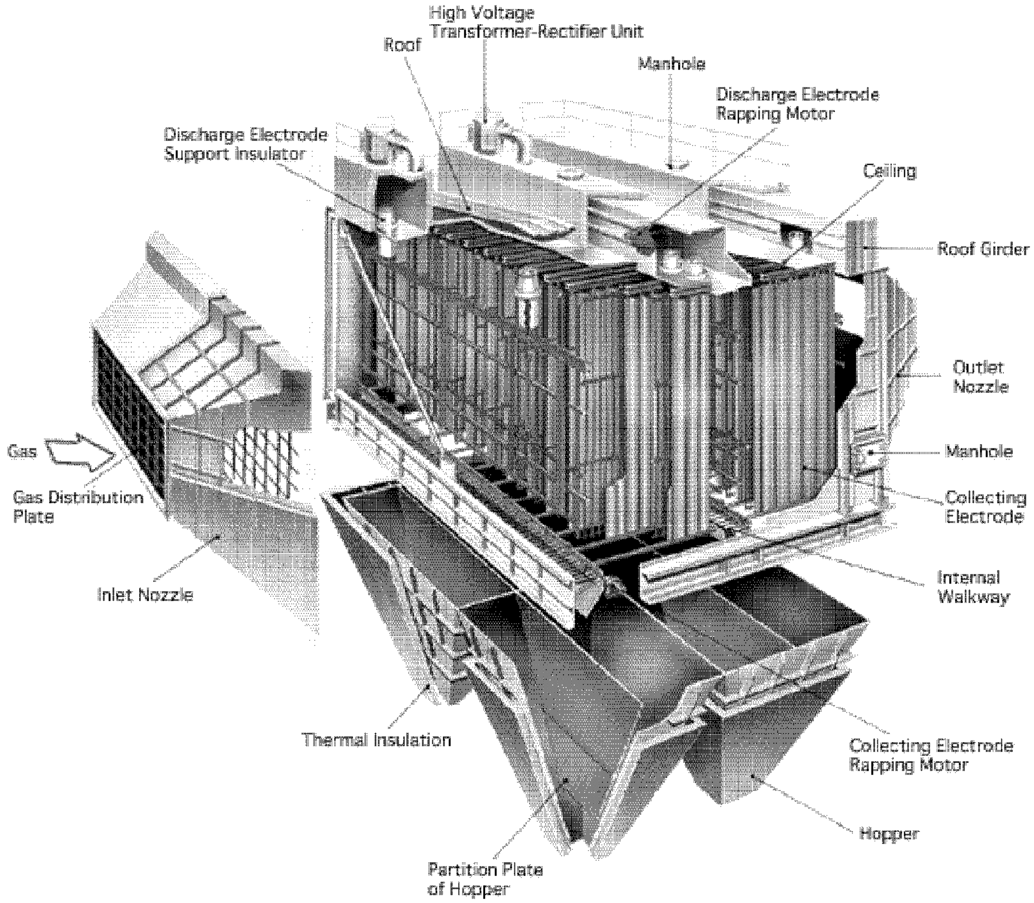


Figure D-10
Electrostatic Precipitator System (MHI)

Pulse Jet Fabric Filter (PJFF)

Fabric filters have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the FF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the FF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental

Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementations. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each FF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure D-11.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

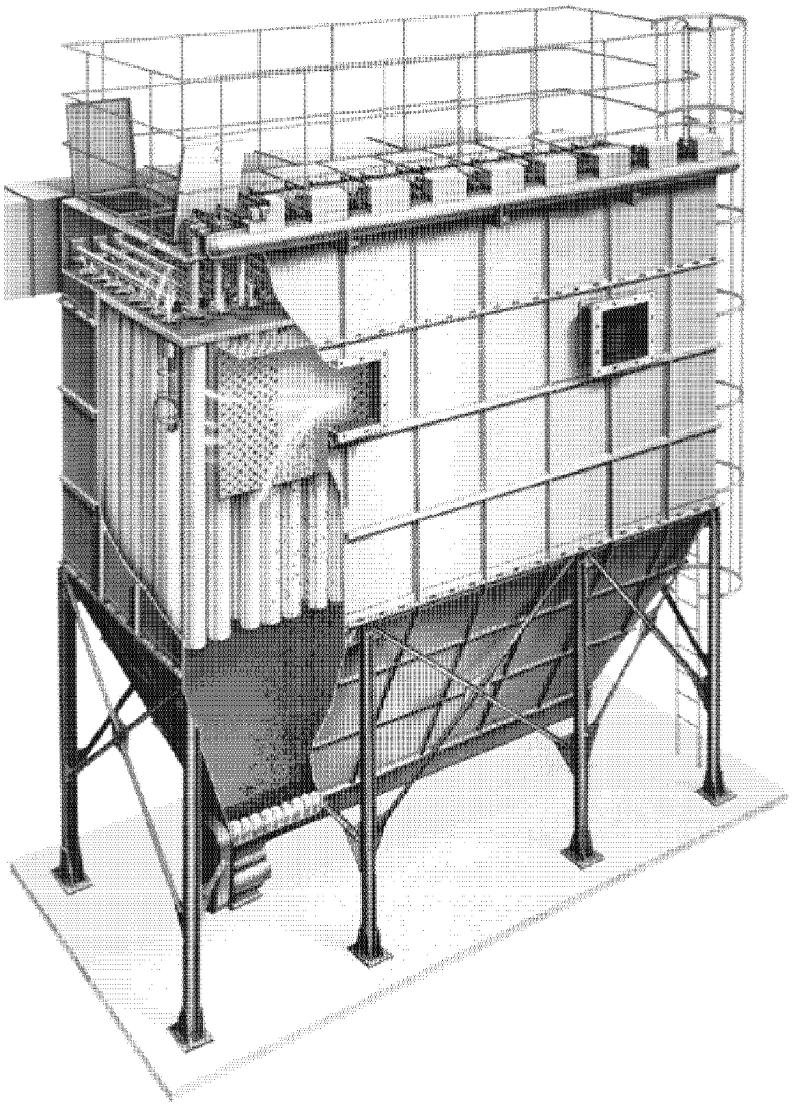


Figure D-11
Pulse Jet Fabric Filter Compartment

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

Compact Hybrid Particulate Collector (COHPAC^{TM})

Another control technology that is effective in removing particulate matter is a high air-to-cloth ratio fabric filter installed after an existing cold-side ESP. Commonly referred to as a Compact Hybrid Particulate Collector (COHPAC^{TM}), this technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC^{TM} filter typically operates at air-to-cloth ratios ranging from 6 to 8 ft/min. compared to a conventional fabric filter that typically operate at air-to-cloth ratios of about 4 ft/min. For a COHPAC^{TM} system, the majority of the particulate is collected in the upstream ESP. Therefore, the performance requirements of a high air-to-cloth ratio fabric filter is reduced allowing installation of this technology in a smaller footprint area, with less steel and filtration media to substantially lower both capital and operating costs compared to conventional fabric filters.

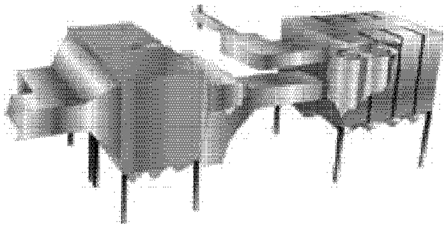


Figure D-12
COHPAC ^{TM} I Arrangement (Courtesy: Hamon Research-Cottrell)

Mercury and Dioxin/Furan Reduction Technologies

Powdered Activated Carbon (PAC) Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of

Energy (DOE), Environmental Protection Agency (EPA), Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure D-13. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

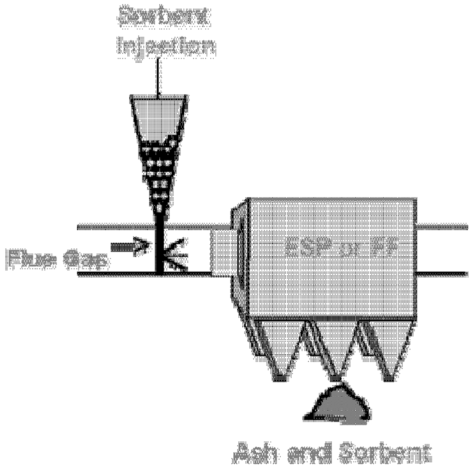


Figure D-13
Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of a ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a cold ESP can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of cold ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a cold ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC: (approximately $5.00/lb of iodine, $1.00/lb of bromine, and $0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

CO Reduction Technologies

Good Combustion Controls

As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits.

Neural Networks

Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions of NOx, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation.

It is recommended that detailed studies be performed to determine the potential benefit from NN installation.

Appendix E
Approved Air Quality Control Technology Options

E.W. Brown

Comments on Brown AQC study by Black and Veatch
Brad Pabian

B&V recommended either a SNCR or SCR on Brown units 1 and 2 in their initial assessment of Brown station. This was due to their assertion that NOx limits would be imposed on a unit by unit basis. If this is the case, then their recommendations are valid. If, however, the NOx limits are imposed on a plant wide basis, then there may be a cheaper alternative. Brown 3 will be fitted with an SCR capable of 0.07 lbs/MMBTU NOx output. If Brown 2 was fitted with a similar SCR, Brown 1 may be able to come into compliance simply with better low NOx burners and over fired air. The rough calculations below show how this may be possible. These are not detailed and accurate numbers, only rough approximations.

Current Unit 3 Full Load Heat Input: ~4700 MMBTU/hr
Current Unit 2 Full Load Heat Input: ~1730 MMBTU/hr
Current Unit 1 Full Load Heat Input: ~1070 MMBTU/hr
Total Plant Full Load Heat Input: ~7500 MMBTU/hr
Maximum Plant Full Load NOx Emissions (at 0.11 lb/MMBTU): 825 lb/hr
Maximum Unit 3 NOx Emissions with 0.07 lb/MMBTU SCR in service: 329 lb/hr
Maximum Unit 2 NOx Emissions with 0.07 lb/MMBTU SCR in service: 121 lb/hr

Maximum allowable Unit 1 NOx Emissions with Unit 2 and 3 SCR in service: 375 lb/hr
Maximum allowable Unit 1 NOx Emission rate: 0.35 lb/MMBTU

Unit 1 currently runs between 0.4 and 0.5 lb/MMBTU, which is the reason that it seemed possible to attain 0.35 lb/MMBTU with less costly means. In addition, when capacity factor is considered, the allowable NOx emission rate on Unit 1 would be higher, since it has historically had a lower capacity factor than the other two units at Brown. I would suggest that capacity factor be treated as safety margin with respect to meeting the limits and that B&V propose a cost to upgrade burner equipment on Unit 1 to achieve approximately 0.3 to 0.32 lb/MMBTU emissions. The only time that this would not be a practical solution would be if the NOx limits were applied on a continuous basis, rather than by year. If so, then a Unit 3 outage would put the plant over the limit. This could be managed, possibly, with overlapping outages, etc. If the NOx regulations are applied on a unit by unit basis, NOx removal of 30-40% by an SNCR as described by B&V would not be capable of bringing Unit 1 into compliance, and a full SCR would be required.

The second major question I had was relative to disposal of material captured by a future baghouse, particularly considering heavy metals that would be captured. Please be sure B&V identifies costs that may be associated with construction of facilities to handle the waste. It should also be made clear in their final document that the potential baghouse requirements for Units 1 and 2 could be met by a single combined baghouse.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NOx compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required****. Existing common WFGD to units 1, 2 and 3 can meet the new* SO_2 *compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available****.* *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected****. Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***1***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

Please clarify if the PJFF is shared between Units 1&2. Also, the plant would prefer B&V to estimate the option of using low NOx burners and overfire air on Unit 1 and put the SCR on Unit 2 and 3 in order to achieve Plant compliance. According to the sheet titled, "Estimated Requirements Under Future New Environmental Regulations" provided to B&V by E.ON, the revised CAIR section 4.9 calls for Plant wide compliance. The Brown Team does not believe that an SCR should be the first option for compliance for this Unit. Please see the attached document prepared by Brad Pabian for further details.

Therefore, B&V should explore this option for the basis of the estimate. Eileen Saunders will discuss with management if E.ON would like B&V to provide costs associated with adding an SCR to Unit 1.

Is an SNCR feasible for the Brown Station? If not, please explain.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***1***

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be located downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – No space is available outside the boiler building on the north side to install the SCR. Therefore, the new SCR needs to be constructed on the east side of the boiler building. Potentially at an elevated level.
- Construction Issues – Tight space for tie-in and connection of ductwork between economizer outlet and SCR.
    - Soot blower air compressor tanks, service water piping and circulating water piping needs to be demolished and relocated.
    - Demineralization system building, which is currently not in use and is located on the north side of the boiler building, needs to be demolished.
    - Secondary air duct may need to be raised to clear the space.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with a shared/common wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***1***

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 1 will be located downstream of the ductwork exiting the ID fans of Unit 1 and upstream of new booster fans for Unit 1.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Heavy foundations and supports.
  - New PJFF will be installed at a higher elevation above the existing ESP, needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***1***

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 1.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 1.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *2*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required****. Existing common WFGD to units 1, 2 and 3 can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***2***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

Please clarify if the PJFF is shared between Units 1&2. If so, B&V needs to make sure that the cost estimate only reflects one baghouse.

See comments on Unit 1 regarding the SCR estimate.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***2***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but not a long term solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be required downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – Limited space available at grade level outside the boiler building on the north side to install the SCR. Therefore the new SCR will need to be constructed at an elevation above grade level.
- Construction Issues – Unit 2 abandoned dry stack and main auxiliary transformer on the north side outside the boiler building.
    - Demolition and relocation of main auxiliary transformer of Unit 2.
    - Demolition of existing pre-dust collectors.
    - SCR will need to be constructed on a dance floor.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with a shared/common wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *2*

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but not a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 2 will be located downstream of the ductwork exiting the ID fans of Unit 2 and upstream of new booster fans for Unit 2.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Heavy foundations and supports.
    - New PJFF will be installed at a higher elevation above the existing ESP, needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***2***

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 2.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 2.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation

Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *The new SCR which will be constructed in 2012 can meet the new NO_x compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required***. *Existing common WFGD to units 1, 2 and 3 can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

No additional comments

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit will be equipped with SCR in 2012 that can meet the future target NO_x emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but not a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 3 will be located downstream of the existing ID fans of Unit 3 and upstream of common wet FGD scrubber.
- Real Estate Constraints – No real estate constraints.
- Construction Issues – Possible underground service water pipelines interference.
    - May require relocation of underground service water pipelines

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 3.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 3.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Ghent

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new* NO_x *compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new* SO_2 *compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBtu emissions.*	☐ Yes ☐ No (See Qualifier in Comments Section)
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x* 10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected***. *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x* 10^{-18} *lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

General Comments for ALL Units:

- In the document, where "South" is used for location, it should be "West"
- For Units 1, 3 and 4, under the section "Special Considerations", please use the phrase, "The plant currently uses an SO3 mitigation system" instead of saying they are "planning injection technology".
- For Unit 2, under the section "Special Considerations", please us the phrase, "The plant will be installing an SO3 mitigation system" instead of saying, "Likely require SO3 mitigation system".
- Please make it clear in the document that the PJFF system must be under negative pressure.
- For SO2, the existing technology can meet the new 0.25 requirements but if the limit becomes more stringent, modifications may have to be made to **consistently** meet the requirements. Please include this clarification in the descriptions of SO2 for all units.
- For various locations cited by B&V as potential locations for PJFF systems, another project run by B&V has plans to locate equipment in those locations (Ash Handling Project). B&V needs to coordinate discussions within their company to ensure that the basis of estimate is accurate. The other project has a 2013 date.

Unit 1 specific comments:

For PM: if this unit is required to meet a new PM limit of .03 lb/MBtu and the Hg Reg does not materialize, the ESP will need to be replaced or upgraded. It does not meet the limit of .03 lb/MBtu on a consistent basis. As long as a PAC/PJFF system is installed to take care of Hg and Dioxin/Furan, then PM will be fine. Please insert this comment on the

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E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

description on the first page. (And include estimate to replace/upgrade.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required.** The unit is currently equipped with an ESP technology that can meet the future target PM emission level of 0.03 lb/MBTU.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 1.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 1.*
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 1 will be located downstream of the existing ID fans of Unit 1 and upstream of the new booster fans for Unit 1.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, with Booster fan or ID fan upgrades.
- Construction Issues – Ductwork and abandoned stack interference. Access for heavy cranes may be a possible issue
    - Require demolition of ductwork
    - May require demolition of existing abandoned dry stack of Unit 1
    - Demolition and relocation of pipe rack for access

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new* NO_x *compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required****. Existing WFGD can meet the new* SO_2 *compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected****. Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

If the Mercury requirement ultimately is by plant and not unit, can Ghent meet the PM requirement without installing a PJFF system on Unit 2?

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E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be required downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – Space is available outside the boiler building on the south side to install the SCR. The SCR will be elevated above grade.
- Construction Issues – Access for heavy equipment and cranes is not available.
  - Demolition and relocation of overhead walkway from Unit 2 to Unit 3 boiler building.
  - Demolition and relocation of some of the overhead power lines.
  - Tower cranes are required for access of heavy equipment and construction of SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 2 will be located downstream of the existing ID fans of Unit 2 and upstream of the new booster fans for Unit 2.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, with Booster fan or ID fan upgrades.
- Construction Issues – Ductwork interference. Access for heavy cranes may be a possible issue
  - Requires demolition of ductwork
  - Demolition and relocation of pipe rack for access

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 2.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 2.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Ghent*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***3***

the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

For the Mercury section, page 4, under "Special Considerations", the wording should be changed to reflect this unit is a hot-side ESP not a cold-side ESP.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:

- **No new NO_x control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 3 will be located downstream of the existing ID fans of Unit 3 and upstream of the new booster fans for Unit 3.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Ghent*
Unit: *3*

- Real Estate Constraints – There is very limited space available between the ID fan outlet and wet scrubber inlet on the west side. The new PJFF will be installed on the south side of Unit 4 ESP, with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole, electrical duct banks and circulating water and storm water drain piping running underground on the south side of Unit 4 ESP will need to be relocated to make real estate available.
    - Warehouse needs to be demolished
    - Well water pumps needs to be relocated

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 3.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 3.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***3***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Ghent*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO$_x$	***No new technology is required***. *Existing SCR can meet the new NO$_x$ compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO$_2$	***No new technology is required***. *Existing WFGD can meet the new SO$_2$ compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBtu emissions.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***4***

and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required** to meet the 0.03 lb/MBTU emissions limit.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Ghent*
Unit: *4*

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 4.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 4.*
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 4 will be located downstream of the existing ID fans of Unit 4 and upstream of the new booster fans for Unit 4.
- Real Estate Constraints – There is very limited space available between the ID fan outlet and wet scrubber inlet on the west side. The new PJFF will be installed on the south side of Unit 4 ESP, with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole, electrical duct banks and circulating water and storm water drain piping running underground on the south side of Unit 4 ESP will need to be relocated to make real estate available.
    - Warehouse needs to be demolished
    - Well water pumps needs to be relocated

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Cane Run

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***4***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new* NO_x *compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new* SO_2 *compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***4***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 4.
- New ID Fans and wet liner/stack required for Unit 4 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***4***

E.ON Comments:

General Comments:

- During the site visits and in subsequent discussions with EON personnel, the outage timeframes were depicted in the 18-20 month range not 20-30 month range. Please explain the discrepancy.
- For the SCR's, an SO3 mitigation system is described as likely needed. To ultimately understand the total cost impact for Cane Run, EON will need to know those costs. Please contact Eileen Saunders regarding this item.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *4*

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 4 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 4 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***4***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 4 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *5*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***5***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 5.
- New ID Fans and wet liner/stack required for Unit 5 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***5***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *5*

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- Location: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *5*

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 5 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 5 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***5***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 5 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 5*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***5***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 6.
- New ID Fans and wet liner/stack required for Unit 6 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *6*

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *6*

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *6*

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 6 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 6 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 6 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 6*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Mill Creek

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu. Plus, new cold-side dry ESP for pre-filtration for ash sales.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Erection of new pre-filter ESP/ and new PJFF and ID fans prior to demolition of existing ESP required in meeting recommended phased approach to create real estate for new SCR.
- SCR will be installed in same physical location as existing ESP.
- Existing wet stack will be reused.
- Phased erection is required to minimize unit outage for tie-in to existing components.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- Existing air heater will be retained
- Existing ESP will be demolished.
- New economizer bypass will be provided
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fans installation is needed.
- Existing WFGD will be demolished in a phased approach.
- Existing ID fans will be demolished
- <u>Location</u>: WFGD would be required downstream of the new ID fans and upstream of the existing stack. The existing wet stack liner and breaching including the connecting ductwork will be reused as is.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fans installation is needed.
- Existing ESP will be demolished.
- A new cold-side dry ESP will be used as a pre-filter to remove 80-85% fly ash that can be sold to the cement plant to lower the ash land filling liability. A new down stream full size PJFF will be used for mercury, acid and some PM control.
- <u>Location</u>: A new PJFF for Unit 1 will be located downstream of the existing air heater and upstream of the new ID fans. The PJFF will possibly be installed on the top of the pre-filter ESP due to site real estate constraints.
- Existing ID fans will be demolished.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP or new proposed cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A full size PJFF is recommended for Unit 1 in conjunction with PAC injection.
- *PAC to be injected downstream of the new pre-filter ESP but upstream of new full size PJFF for Unit 1*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost[*]
NO$_x$	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO$_x$ compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO$_2$	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO$_2$ compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu. Plus, new cold-side dry ESP for pre-filtration for ash sales.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Erection of new pre-filter ESP/ and new PJFF and ID fans prior to demolition of existing ESP required in meeting recommended phased approach to create real estate for new SCR.
- SCR will be installed in same physical location as existing ESP.
- Existing wet stack will be reused.
- Phased erection is required to minimize unit outage for tie-in to existing components.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- Existing air heater will be retained
- Existing ESP will be demolished.
- New economizer bypass will be provided
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fans installation is needed.
- Existing WFGD will be demolished in a phased approach.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the existing stack. The existing wet stack liner and breaching including the connecting ductwork will be reused as is.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fans installation is needed.
- Existing ESP will be demolished.
- A new cold-side dry ESP will be used as a pre-filter to remove 80-85% fly ash that can be sold to the cement plant to lower the ash land filling liability. A new down stream full size PJFF will be used for mercury, acid and some PM control.
- Location: A new PJFF for Unit 2 will be located downstream of the existing air heater and upstream of the new ID fans. The PJFF will possibly be installed on the top of the pre-filter ESP due to site real estate constraints.
- Existing ID fans will be demolished.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP or new proposed cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A full size PJFF is recommended for Unit 2 in conjunction with PAC injection.
- *PAC to be injected downstream of the new pre-filter ESP but upstream of new full size PJFF for Unit 2*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x10^{-18} lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- New booster fans required following PJFF.
- New ductwork will bypass existing FGD equipment that will be demolished following installation of new equipment.
- Existing stack can be reused with new FGD and PJFF elevated above existing road and rails.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***3***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing WFGD will be demolished.
- Location: WFGD would be required downstream of the new booster fans and upstream of the existing stack.
- New wet FGD absorber and reaction tank to be installed over the existing main access way on elevated steel supports and hence heavy duty steel support and foundations are expected. *Existing railroad tracks as well as pipe racks are kept intact by elevating the new PJFF and the WFGD absorber.*

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation is needed.
- Existing ESP to be kept for additional PM filtration and lime injection for SO_3 mitigation to be located upstream of existing ESP.
- Location: A new PJFF for Unit 3 will be located over the main access way downstream of the existing ID fans and upstream of the new booster fans.
- Real Estate Constraints – No space is available at grade level to install the new PJFF because the existing access way is critical to plant operation. Therefore the new PJFF will need to be constructed at an elevation above grade level, with new Booster fans.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF in conjunction with PAC injection is recommended for Unit 3.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 3*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required****. Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***4***

and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- New booster fans required following PJFF.
- New ductwork will bypass existing FGD equipment that will be demolished following installation of new equipment.
- Existing stack can be reused with new FGD and PJFF elevated above existing road and rails.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***4***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- **<u>No new NOx control technology is required</u>**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing WFGD will be demolished.
- <u>Location</u>: WFGD would be required downstream of the new booster fans and upstream of the existing stack.
- <u>New wet FGD absorber and reaction tank to be installed over the existing main access way on elevated steel supports and hence heavy duty steel support and foundations are expected</u>. *Existing railroad tracks as well as pipe racks are kept intact by elevating the new PJFF and the WFGD absorber.*

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *4*

- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation is needed.
- Existing ESP to be kept for additional PM filtration and lime injection for SO_3 mitigation to be located upstream of existing ESP.
- <u>Location</u>: A new PJFF for Unit 4 will be located over the main access way downstream of the existing ID fans and upstream of the new booster fans.
- <u>Real Estate Constraints</u> – No space is available at grade level to install the new PJFF because the existing access way is critical to plant operation. Therefore the new PJFF will need to be constructed at an elevation above grade level, with new Booster fans.

Pollutant: CO

Feasible Control Options:

- ***<u>No feasible and proven technology is available for this type and size of unit</u>*** to meet the 0.02 lb/MBtu emission limit.
- *<u>Note</u>*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *4*

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF in conjunction with PAC injection is recommended for Unit 4.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Trimble County

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Trimble County*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NOx compliance limit of 0.11 lb/MBtu*	☐ Yes ☐ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	☐ Yes ☐ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBTU emissions.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU* *(Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size PJFF.***	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection*** *and new Pulse Jet Fabric Filter (PJFF) required to meet the compliance requirements.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Trimble County***
Unit: ***1***

E.ON Comments:

Under the “Special Considerations” section for Hg, B&V discusses the use of adding a booster fan or upgrading the ID fan. The plant would prefer to upgrade the existing ID Fan motors which will need to be replaced or rewound. Modifications will need to be made to the ID Fans which may include replacement of the fans.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Trimble County***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- **No new NO_x control technology is required**. The unit is currently equipped with state of the art SCR that can meet future target NOx emissions level of 0.11 lb/MBtu.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required** to meet the 0.03 lb/MBTU emissions limit.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Trimble County*
Unit: *1*

continuous basis and hence is the most feasible control technology. The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.

Special Considerations:

- Full size PJFF.
- *PAC to be injected downstream of the existing ESP but upstream of new PJFF.*
- Location: A PJFF would be required downstream of the PAC injection system.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole and electrical duct banks running underground between the existing ID fans and scrubber inlet duct will need to be avoided or relocated to make real estate available.
  - Array of I-beam structures (currently supporting no equipment) located between the existing ID fans and scrubber inlet needs to be demolished.
  - New PJFF will be installed at a higher elevation needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- The **new PAC injection with new PJFF considered for mercury control** can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Trimble County***
Unit: ***1***

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Green River

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Circulating Dry Scrubber (CDS) Desulfurization is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) which is part of the CDS technology for SO_2 removal is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***New CDS technology*** *can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- New ID Fans, Air Heater and dry carbon steel Stack required for Unit 3.
- Underground aux electric duct banks need to be avoided during foundations for future AQC equipment.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New ID fan installation is needed.
- Existing air heater will be demolished and used as SCR ductwork.
- New air heater.
- New economizer bypass will be built
- Location: SCR would be required downstream of the existing economizer and upstream of the new air heater. New air heater to be located straight under the new SCR.

Pollutant: SO_2

Feasible Control Options:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:

- Both WFGD and Semi-Dry FGD systems will be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu on a continuous basis on high sulfur fuels. However for small size boilers like Unit 3, it would be economically feasible to build a semi-dry FGD or CDS system than Wet FGD system. The CDS system will offer more operational flexibility compared to the two other technologies when load flexibility is an issue. The CDS technology will incorporate an internal flue

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *3*

gas recycle to maintain the lime bed during low load operations. Hence CDS is the most feasible control technology considered for SO_2 reduction based on the size of the unit.

- New ID fan installation is needed.
- Existing ID fans will be demolished
- Location: CDS would be required downstream of the new air heater and upstream of the new ID fans.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold Side Dry ESP
- COHPAC^{TM}.
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation is needed.
- Existing ESP will be retired in place. This will not be demolished. Exhaust gas stream will bypass the existing ESP.
- Location: A new PJFF for Unit 3 will be located downstream of the new CDS and upstream of the new ID fans.
- Existing ID fans will be demolished.
- New Air Heater will be installed straight under the new SCR.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF for Unit 3 is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the new air heater but upstream of CDS FGD system for Unit 3

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:

- WFGD, Semi-Dry FGD, and CDS systems will be able to achieve the new HCl compliance limit of 0.002 lb/MBtu on a continuous basis.
- However, since a new CDS system will be installed for SO_2 control, it will also control HCl. Therefore, no new HCl control technology is required beyond the proposed CDS. The new CDS technology with PJFF will remove the HCl to the compliance levels of 0.002 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new CDS and PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new* NO_x *compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Circulating Dry Scrubber (CDS) Desulfurization is required*** *to meet the new* SO_2 *compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) which is part of the CDS technology for*** SO_2 ***removal is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***New CDS technology*** *can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	☐ Yes ☐ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- New ID Fans and dry carbon steel Stack required for Unit 4. Booster fans options to be evaluated.
- Relocate existing power lines and tower.
- Will require demolition of abandoned Unit 1 and Unit 2 ID fans, scrubber and stack to make room for Unit 4 new AQC equipment.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

E.ON Comments:

- Under Special Considerations Summary, the Unit 1 and Unit 2 ID fan statement is incorrect. There is only one fan and it is a booster fan that was originally used for the scrubber.
- For the entire station, there is no extra Aux Power. Any estimate has to include and upgrade to that system as the current system cannot handle any additional power requirements.
- For the SCR considerations for Units 3 and 4, the estimate should include new, enamel air heater baskets as discussed during the site visits.
- The estimate should include ductwork replacement as the current ductwork is in poor condition.
- In the Green River Unit 4 template, on page 4 of 7, it should read, “Unit 4” instead of “Unit 3” under the Special Consideration’s section.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigate system.
- New ID fan installation is needed if booster fans do not make sense.
- Existing air heater will be used
- New economizer bypass will be built
- <u>Location</u>: SCR would be required downstream of the existing hot-side ESP and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:

- Both WFGD and Semi-Dry FGD systems will be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu on a continuous basis on high sulfur fuels. However for small size boilers like Unit 3, it would be economically feasible to build a semi-dry FGD or CDS system than Wet FGD system. The CDS system will offer more operational flexibility compared to the two other technologies when load flexibility is an issue. The CDS technology will incorporate an internal flue gas recycle to maintain the lime bed during low load operations. Hence CDS is the most feasible control technology considered for SO_2 reduction based on the size of the unit.

- New ID fan installation is needed if booster fans do not make sense.
- Existing ID fans will be retired in place if new ID fans are used in lieu of booster fans.
- <u>Location</u>: CDS would be required downstream of the existing air heater and upstream of the new ID fans. Existing ID fans located at higher elevation will either be retired in place if new ID fans are selected or reused when new booster fans are added CDS with new dry carbon steel stack.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold Side Dry ESP
- COHPAC^{TM}.
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation is needed if booster fans do not make sense.
- Existing hot side ESP to be kept to minimize the arrangement challenges for new SCR. The existing ESP will remain functional (energized) and used for additional PM filtration.
- <u>Location</u>: A new PJFF for Unit 4 will be located downstream of the new CDS and upstream of the new ID fans.
- Existing ID fans will be retired in place if new ID fans are used in lieu of booster fans.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 4.
- *PAC to be injected downstream of the existing air heater but upstream of CDS FGD system for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:

- WFGD, Semi-Dry FGD, and CDS systems will be able to achieve the new HCl compliance limit of 0.002 lb/MBtu on a continuous basis.
- However, since a new CDS system will be installed for SO_2 control, it will also control HCl. Therefore, no new HCl control technology is required beyond the proposed CDS. The new CDS technology with PJFF will remove the HCl to the compliance levels of 0.002 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

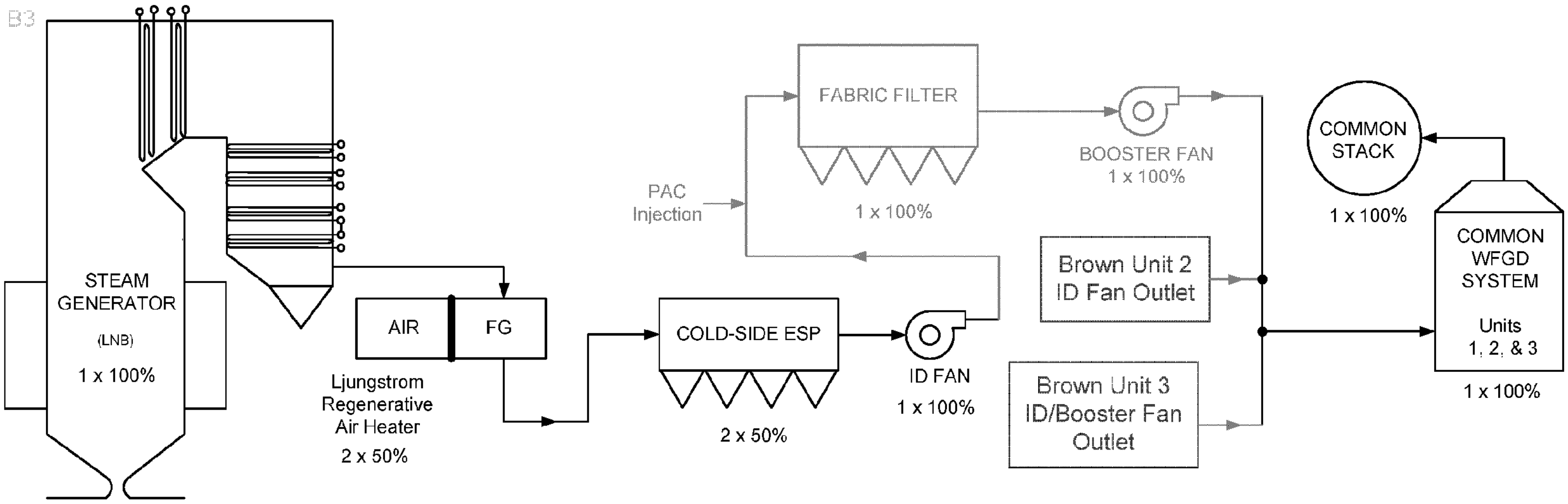
- PAC injection with new CDS and PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

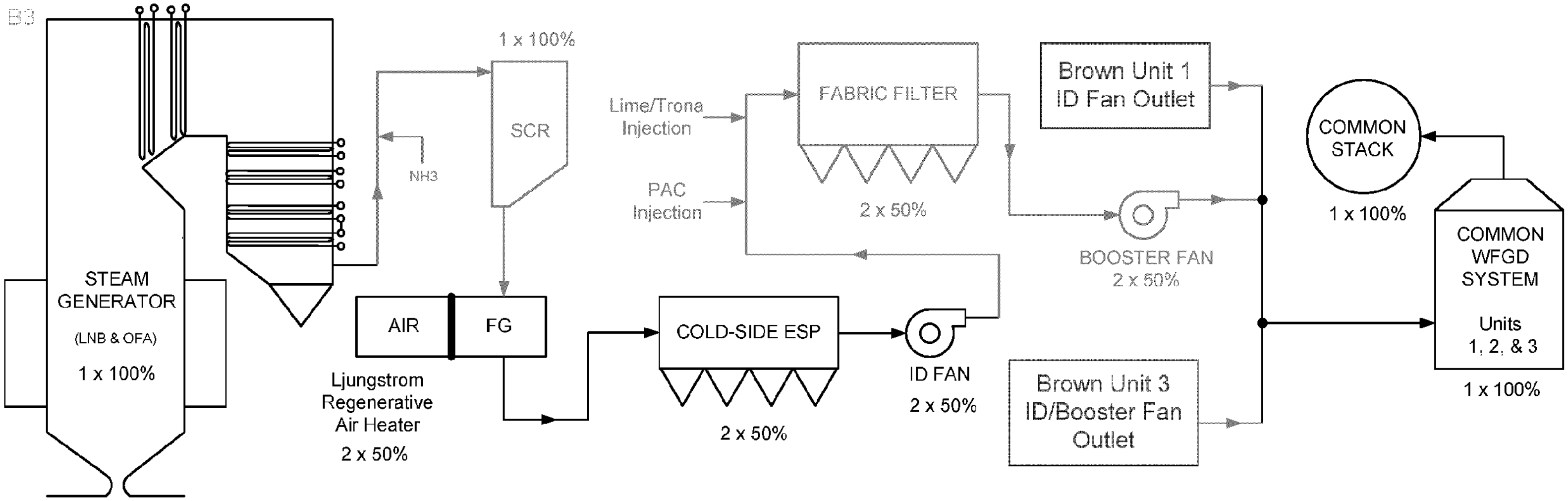
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Appendix F
Process Flow Diagrams

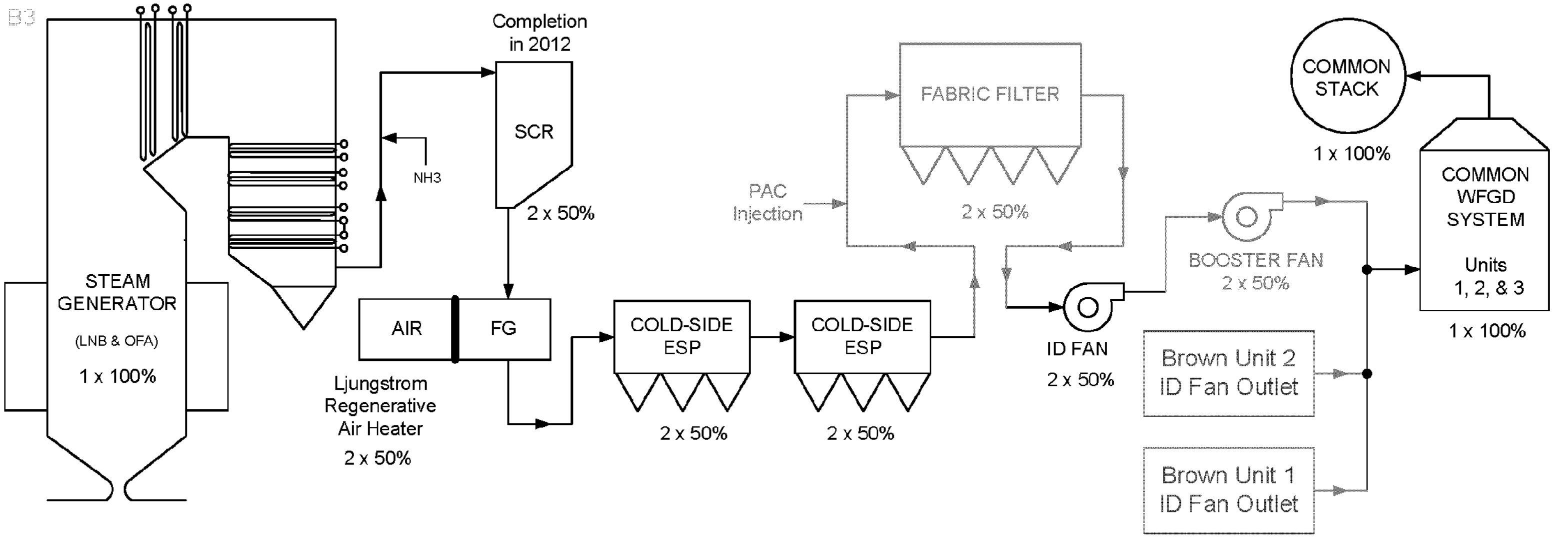
E.W. Brown



Brown Unit 1: Future
110 MW

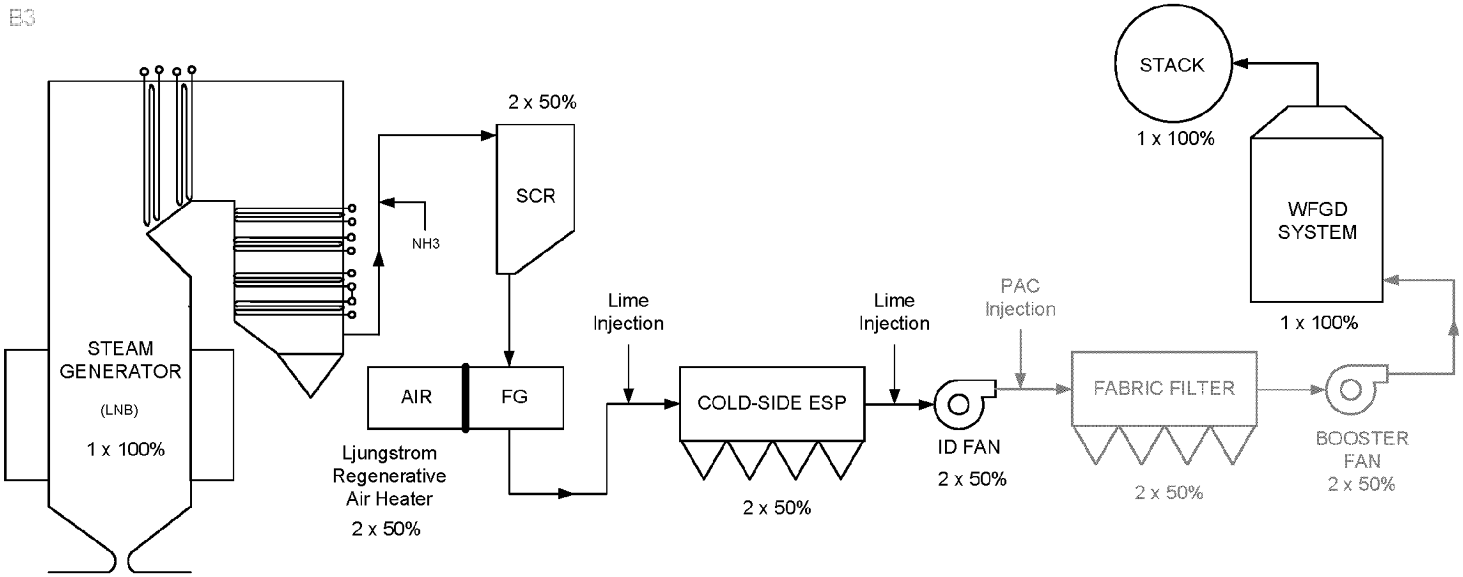


Brown Unit 2: Future
180 MW

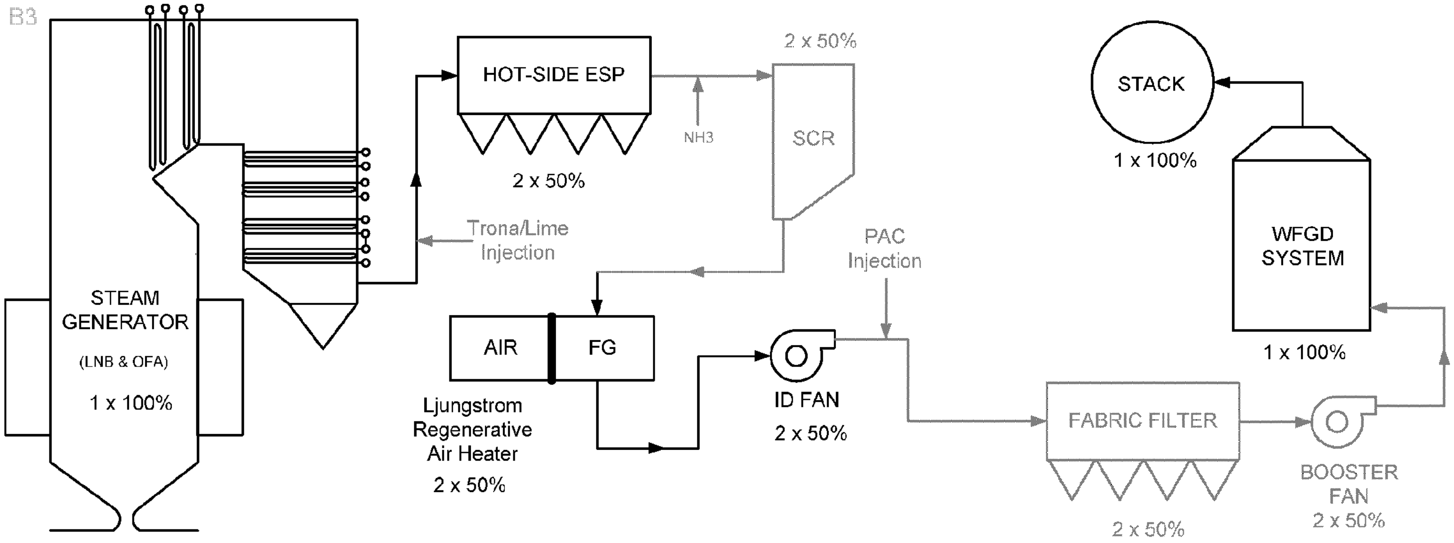


Brown Unit 3: Future
457 MW

Ghent



Ghent Unit 1: Future



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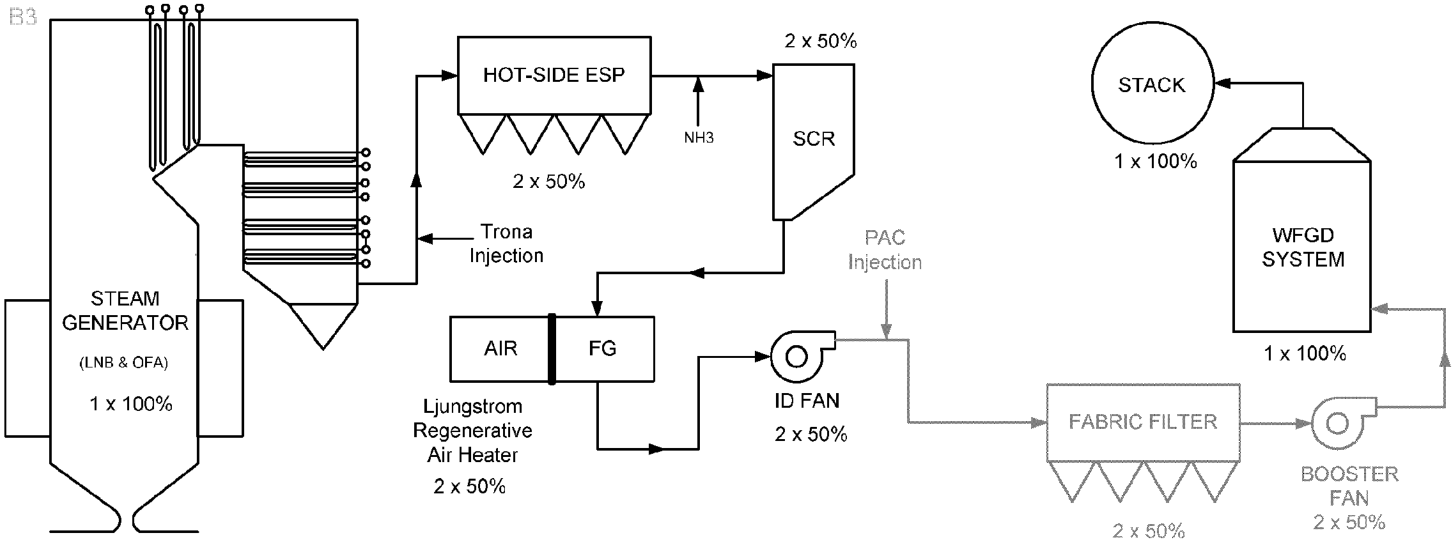
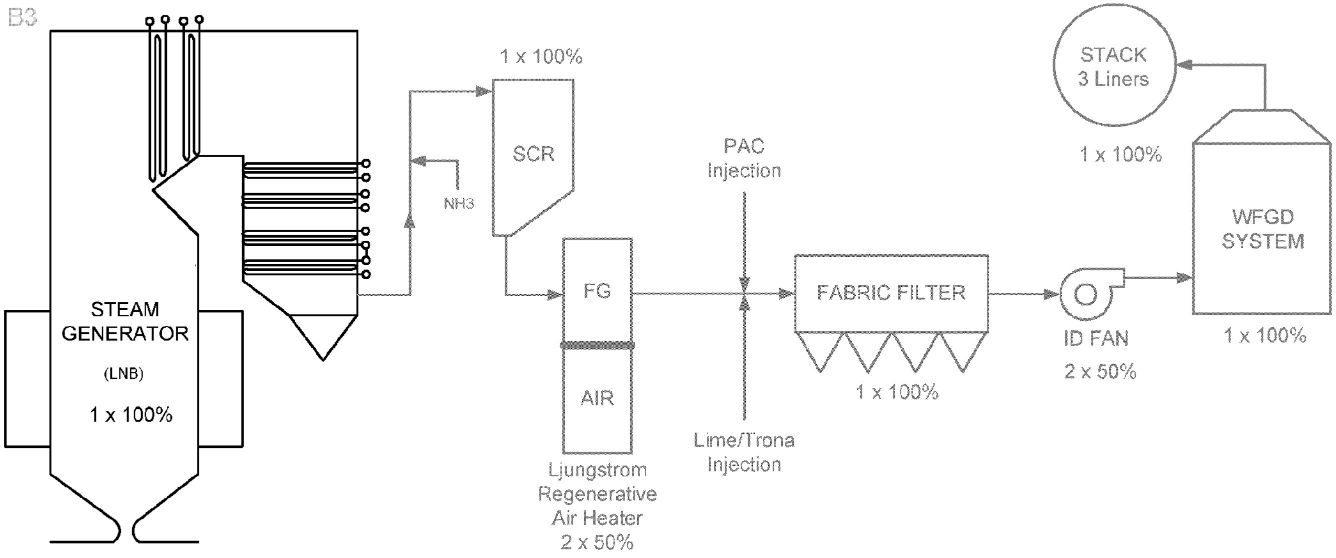
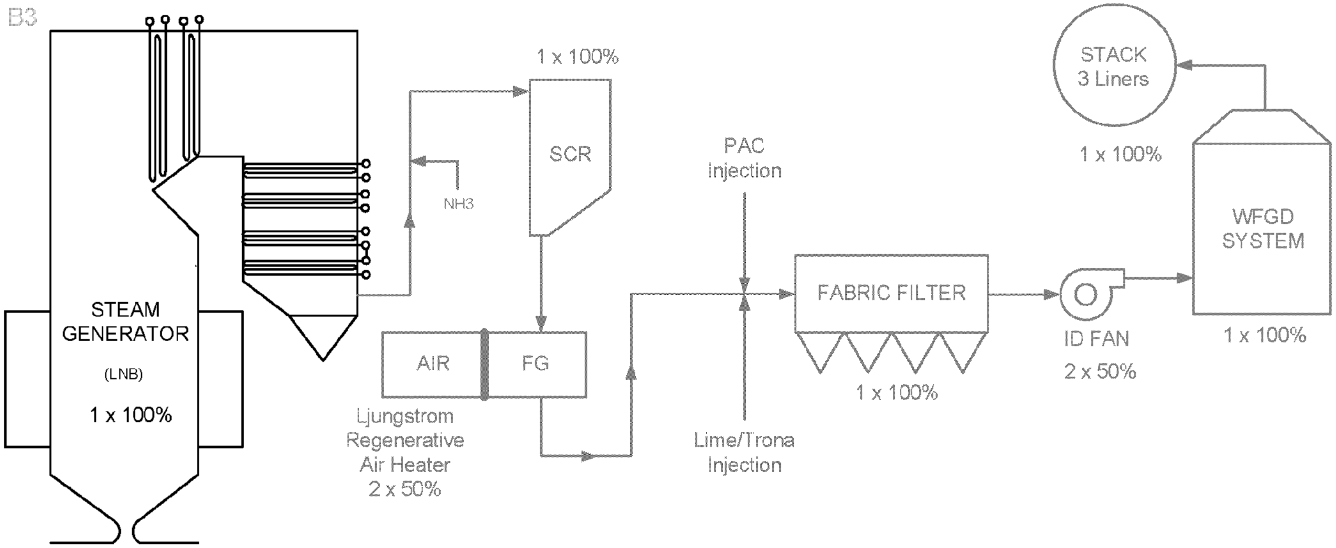


Ghent Unit 3/4: Future

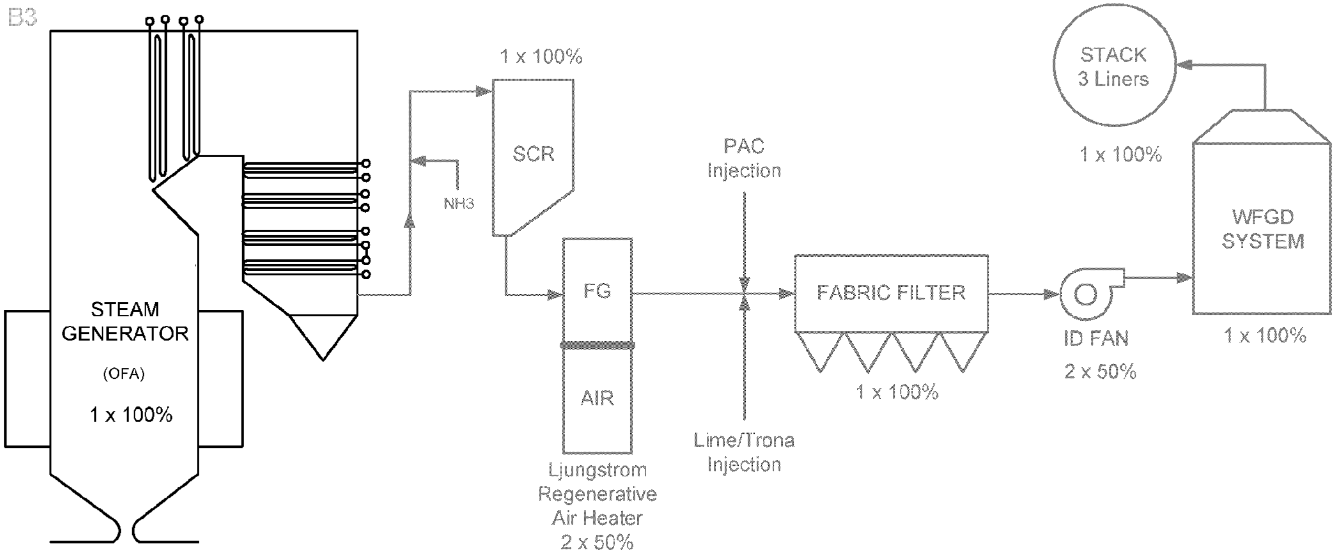
Cane Run



Cane Run Unit 4: Future
168 MW

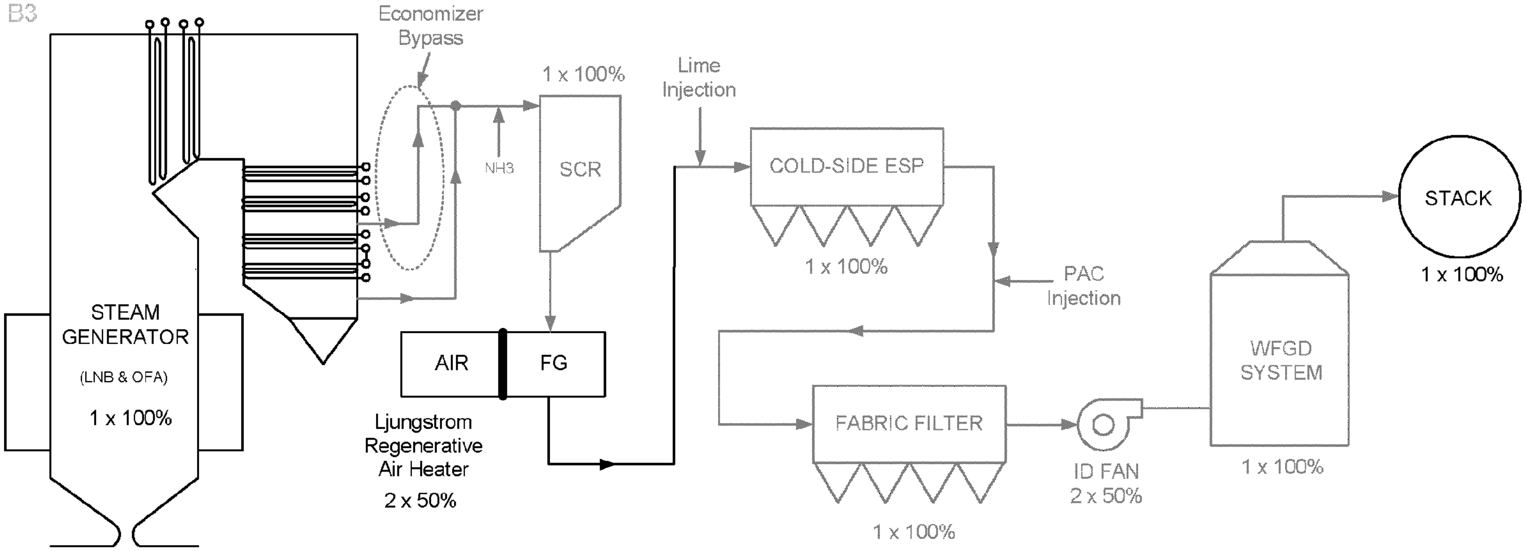


Cane Run Unit 5: Future
181 MW

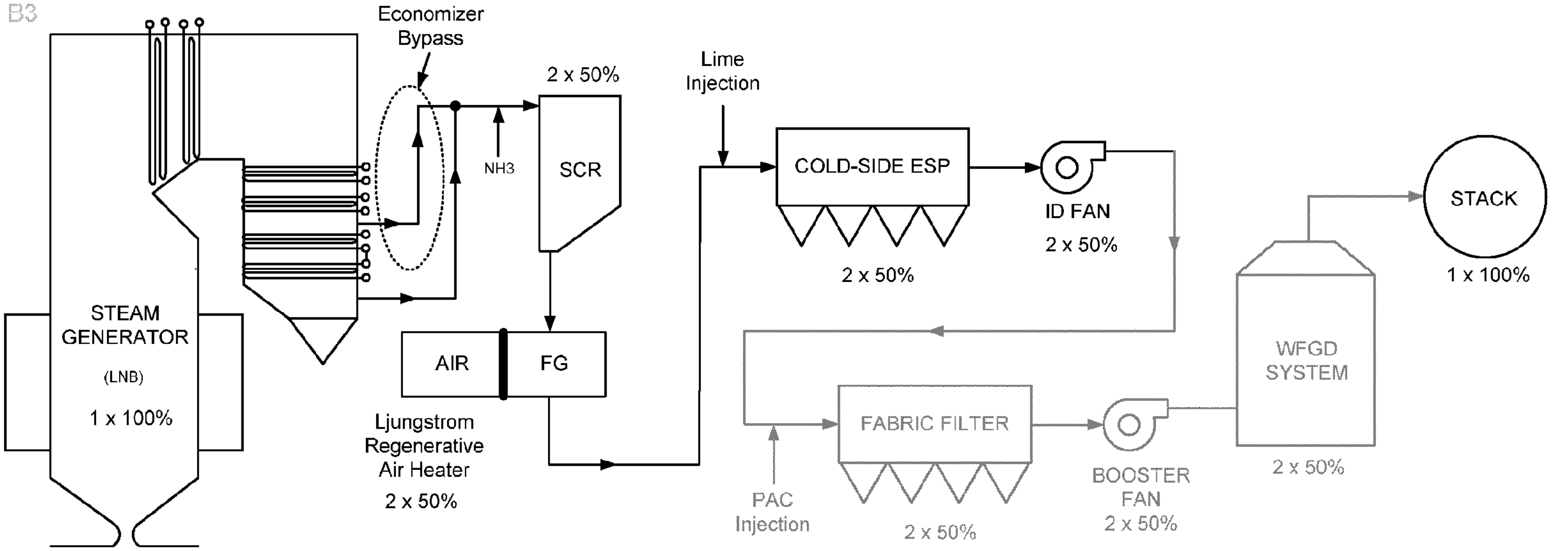


Cane Run Unit 6: Future
261 MW

Mill Creek

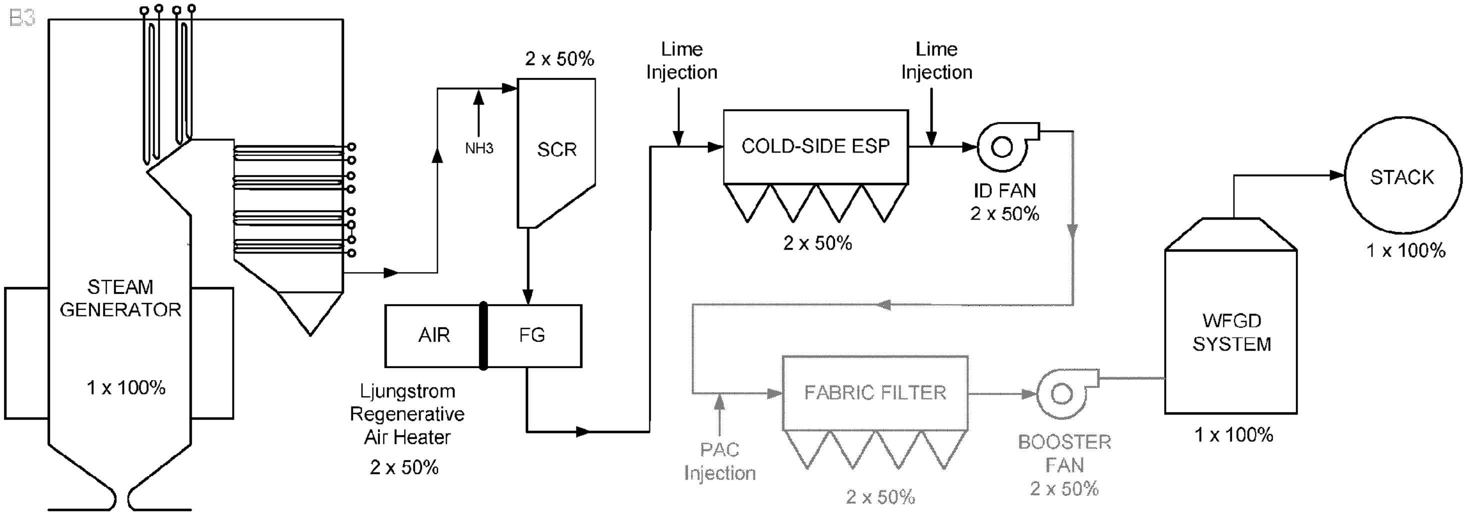


Mill Creek Unit 1/2: Future
Unit 1: 330 MW
Unit 2: 330 MW



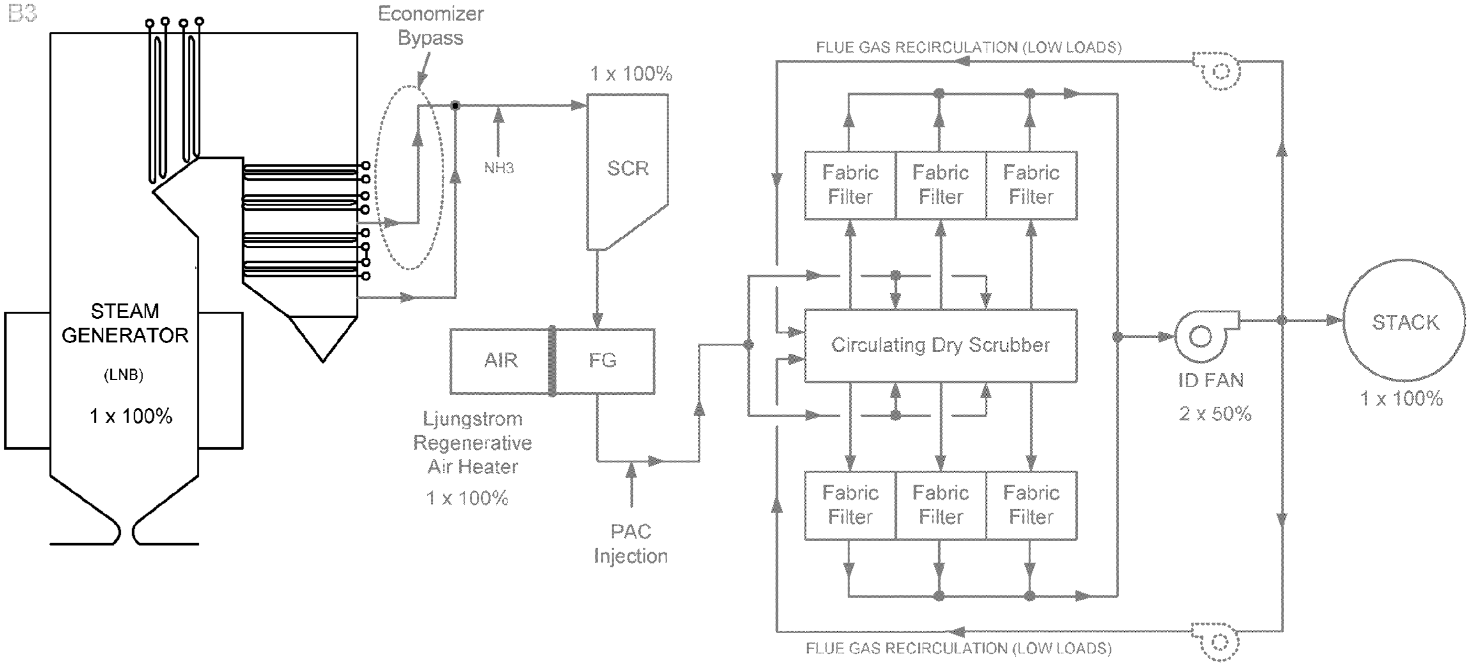
Mill Creek Unit 3/4: Future
Unit 3: 423 MW
Unit 4: 525 MW

Trimble County

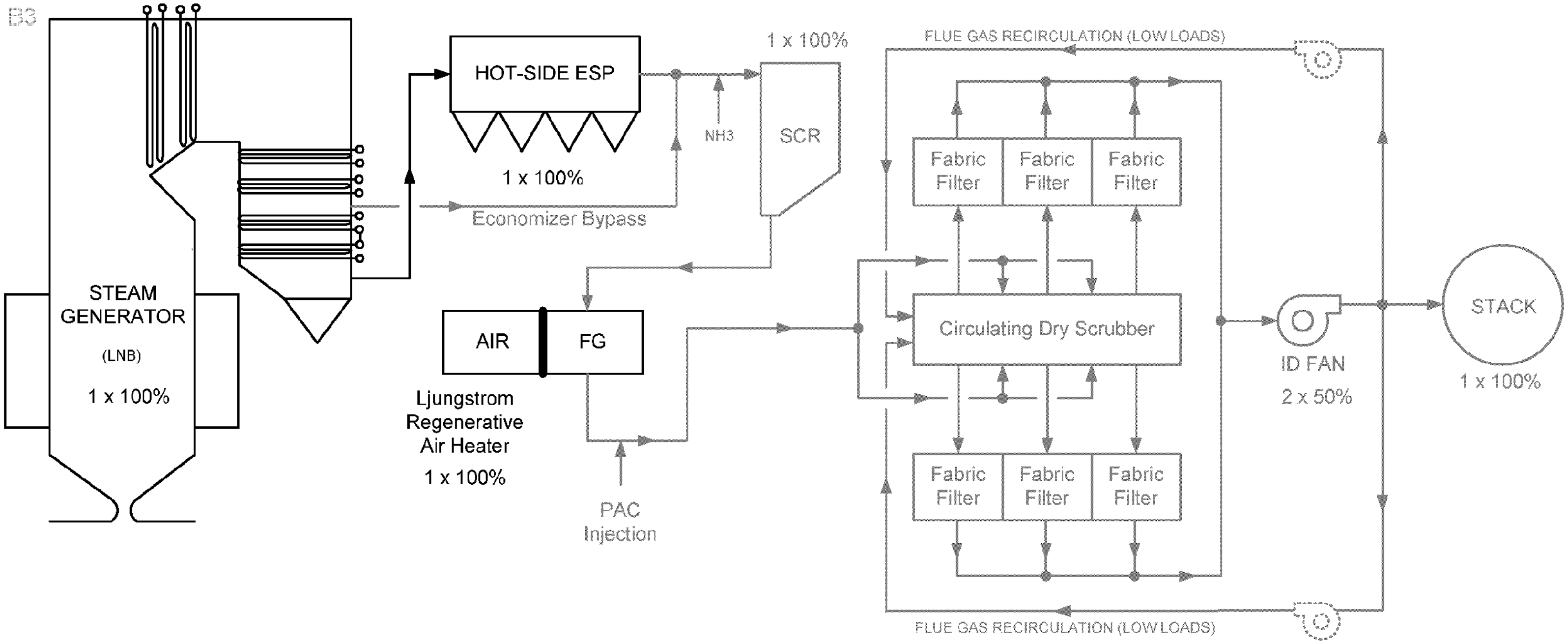


Trimble County Unit 1: Future

Green River



Green River Unit 3: Future
71 MW



Green River Unit 4: Future
109 MW

Appendix G
Air Quality Control Equipment Arrangement Drawings

E.W. Brown

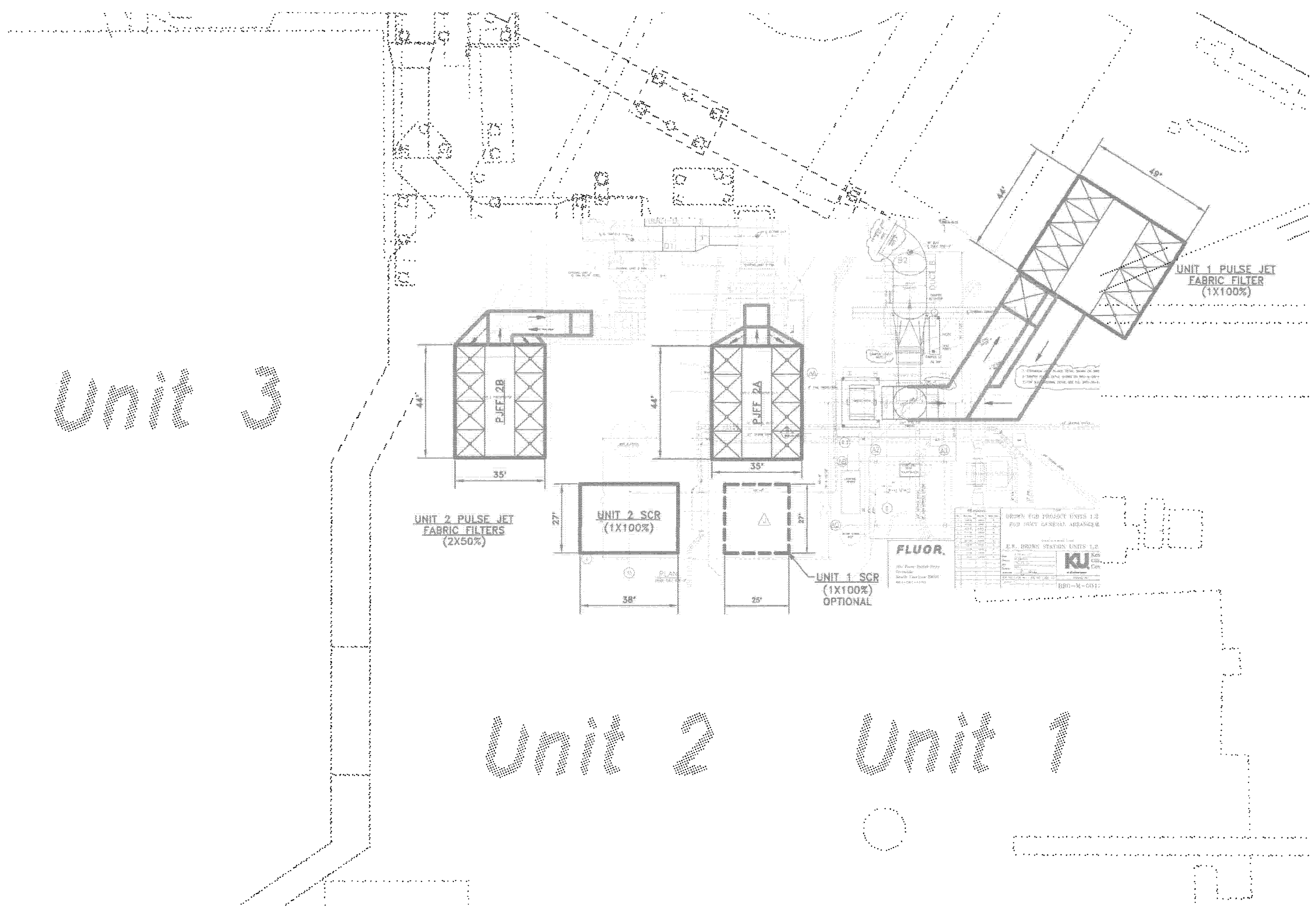
E.W. Brown Units 1 & 2
Constructability Challenges

SCR Constructability Challenges

- Real estate constraints for Unit 1 & Unit 2 SCR
- The new SCR duct tie-ins to the existing Unit 1 Air Heater inlet duct will require extensive relocation of existing plant components:
    1. Rotate Secondary Air Heater Duct
    2. Modify boiler building structural steel bracing and girts to accommodate ductwork
    3. Relocate 440V Switchgear 1A and 1B
- The new SCR duct tie-ins to the existing Unit 2 Air Heater inlet duct will require boiler building structural steel bracing and girts to be modified to accommodate ductwork
- The new Unit 2 SCR support structure and reactor box will require extensive relocation/demolition of existing plant components:
    1. Relocate or protect field fabricated tank located in base of abandoned Unit 2 chimney shell
    2. Demolish Unit 2 chimney
    3. Demolish the dust collection ductwork located along the northeast exterior wall of Unit 2 boiler building
    4. Relocate Unit 2 Auxiliary Transformer located outside of the northeast exterior wall of Unit 2 boiler building
- The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR structure to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR and fabric filter modules

PJFF Constructability Challenges

- Real estate constraints for Unit 2 PJFF
- Elevated PJFF for Unit 2
- Extensive underground investigation will be required to identify operating utilities prior to installing new foundations for Unit 2 fabric filter structural steel support frame.
- The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit Fabric Filter structure to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR and fabric filter modules
- Heavy foundations required on the outer ends of Unit 2 ESP's for construction of Unit 2 PJFF.
- Difficult to stage construction equipment for ductwork support frame & associated foundations near ID fans of Unit 1 & Unit 2



LEGEND:
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NEW DUCTWORK= ▬

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BLACK & VEATCH
CORPORATION

E.ON.
E W BROWN UNITS 1 & 2 SCR

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT	DRAWING NUMBER		REV
167987	CAQC-M1006		0
ENGINEER	DRAWN MLW	CODE	
CHECKED	DATE	AREA	

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E.W. Brown Unit 3

Constructability Challenges

- Relocate ductwork and associated support steel for tie-in.
- Relocate underground utilities

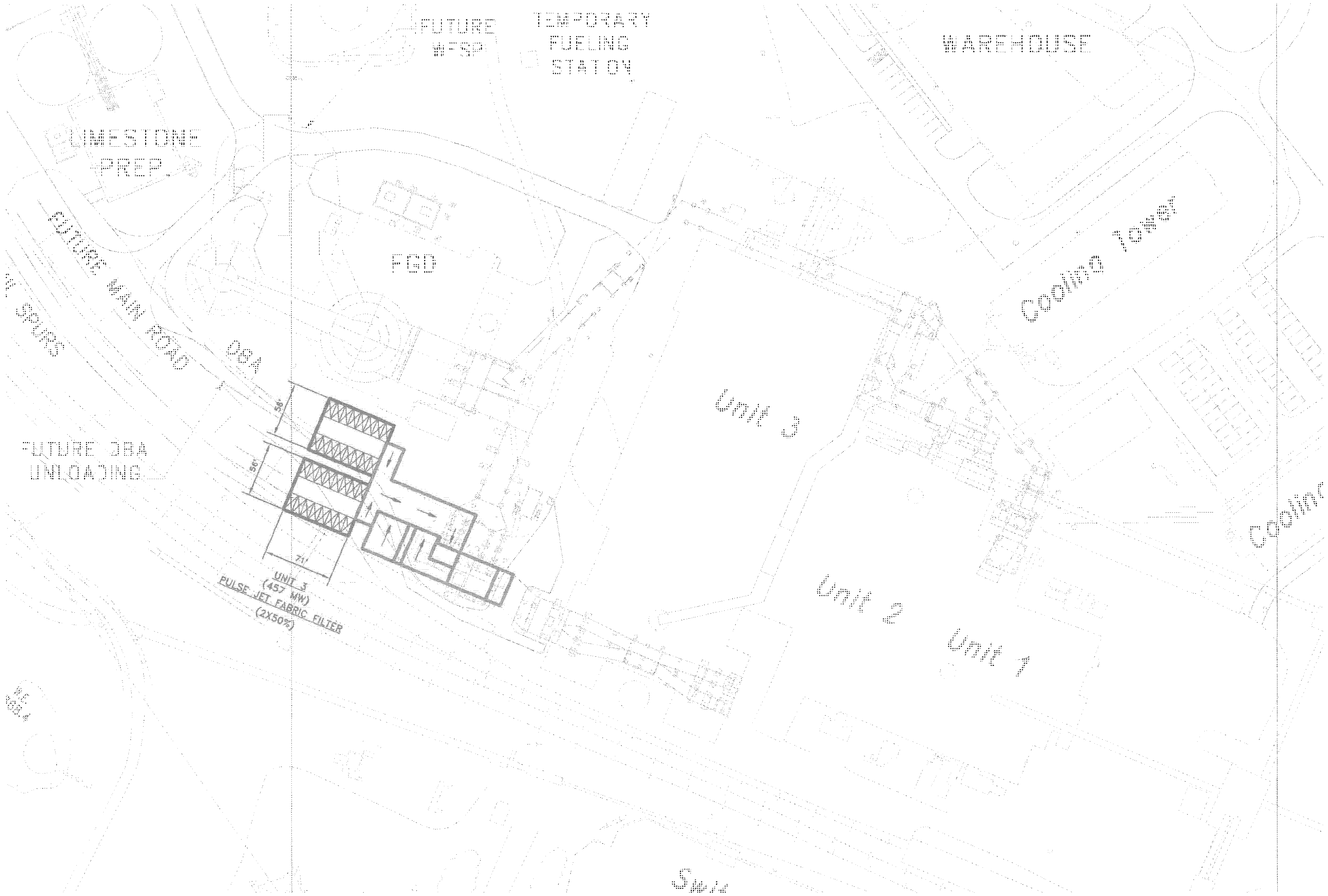
AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:

NEW EQUIPMENT =

NEW DUCTWORK =



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1"=500'

BLACK & VEATCH CORPORATION

ENGINEER
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E.ON.
E W BROWN UNITS 1, 2 & 3

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER
167987–CAQC–M1005

REV 0

CODE
AREA

Ghent

Ghent Unit 1

Constructability Challenges

- Real estate constraints
- Elevated New Pulse Jet Fabric Filter
- Crane access is difficult at Unit 1 due to low overhead pipe rack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or permanently relocated. Lattice boom crawler crane booms will need to be final assembled at the working location.
- Access lanes around Unit 1 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area.

AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:

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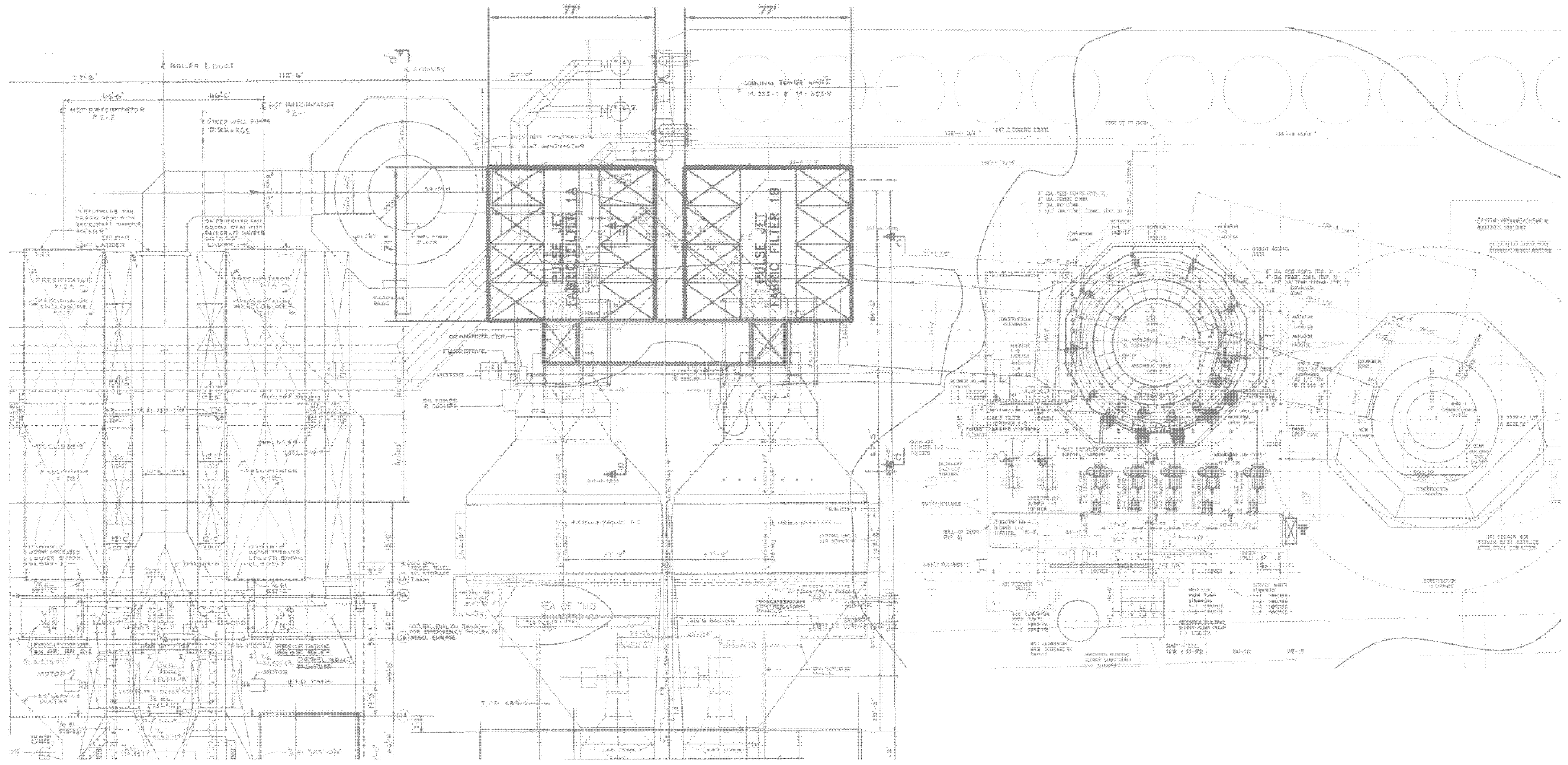
NEW DUCTWORK= ▬



PULSE JET FABRIC FILTERS
(2X50%)

NOT TO BE USED
FOR CONSTRUCTION

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1"=300'

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CORPORATION

ENGINEER
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E.ON.
GHENT – UNIT 1

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER 167987–CAQC–M1001
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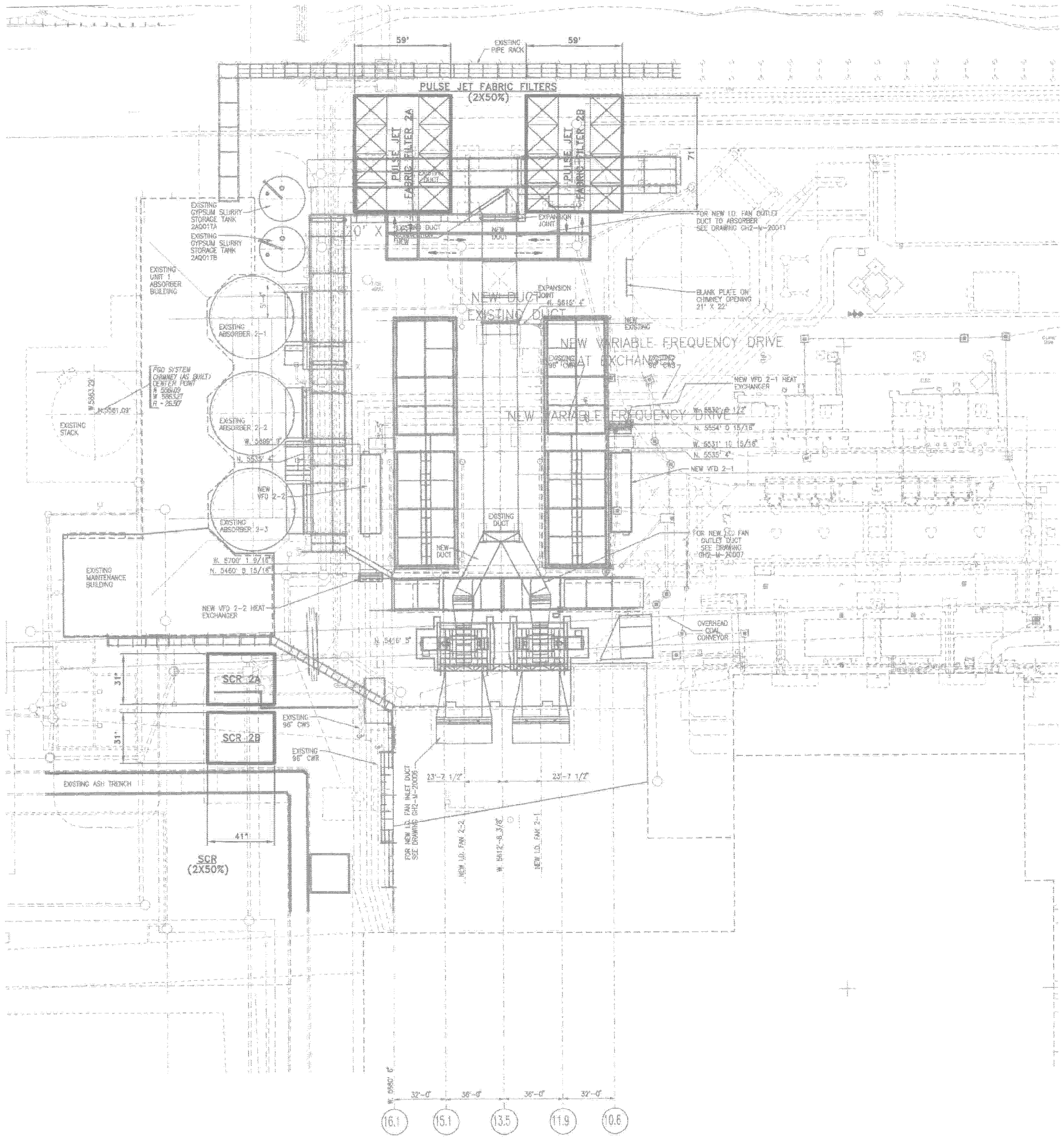
AREA



PLAN VIEW
EL 480'-0" THRU 550'-0"

Ghent Unit 2 Pulse Jet Fabric Filter

Constructability Challenges

- Real estate constraints
- Elevated Pulse Jet Fabric Filter
- Crane access is difficult at Unit 2 due to low overhead pipe rack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or relocated. Lattice boom crawler crane booms will need to be final assembled at the working location.
- Access lanes around Unit 2 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area.
- Current arrangement for Unit 2 fabric filters require a section of by-pass ductwork to be installed in order to isolate/demolish existing ductwork/duct supports and provide the required footprint for the new equipment. Tie in portions of this work scope must be accomplished during early plant outages.

Ghent Unit 2 SCR

Constructability Challenges

- Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.
- Demolition of overhead walkway.
- Possible use of tower crane for final assembly of SCR
- Demolition & Relocation of pipe rack.

AQC Technology and Equipment

- Selective Catalyst Reduction
- Pulse Jet Fabric Filter

LEGEND:

NEW EQUIPMENT= ▬
NEW DUCTWORK= ▬

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1" =300'

BLACK & VEATCH
CORPORATION

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DATE

E.ON.
GHENT – UNIT 2

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

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CODE
AREA

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Ghent Units 3&4

Constructability Challenges

- Current arrangement for Unit 3 fabric filters requires an extensive length of inlet/outlet ductwork to be routed above and across the existing Unit 3 & 4 ESP's. Access around the footprint of the ESP's is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations.
- Crane access will be restricted around the tie in for Unit 3 fabric filter inlet/outlet ductwork.
- Existing underground electrical manholes, water wells, storm sewer boxes and piping, and circulating cooling water piping all run in the proposed footprint for Unit 4 fabric filter. The electrical manholes, water wells, and storm sewer piping will need to be relocated in order to install the foundations for the Unit 4 fabric filter structural frame.

AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:

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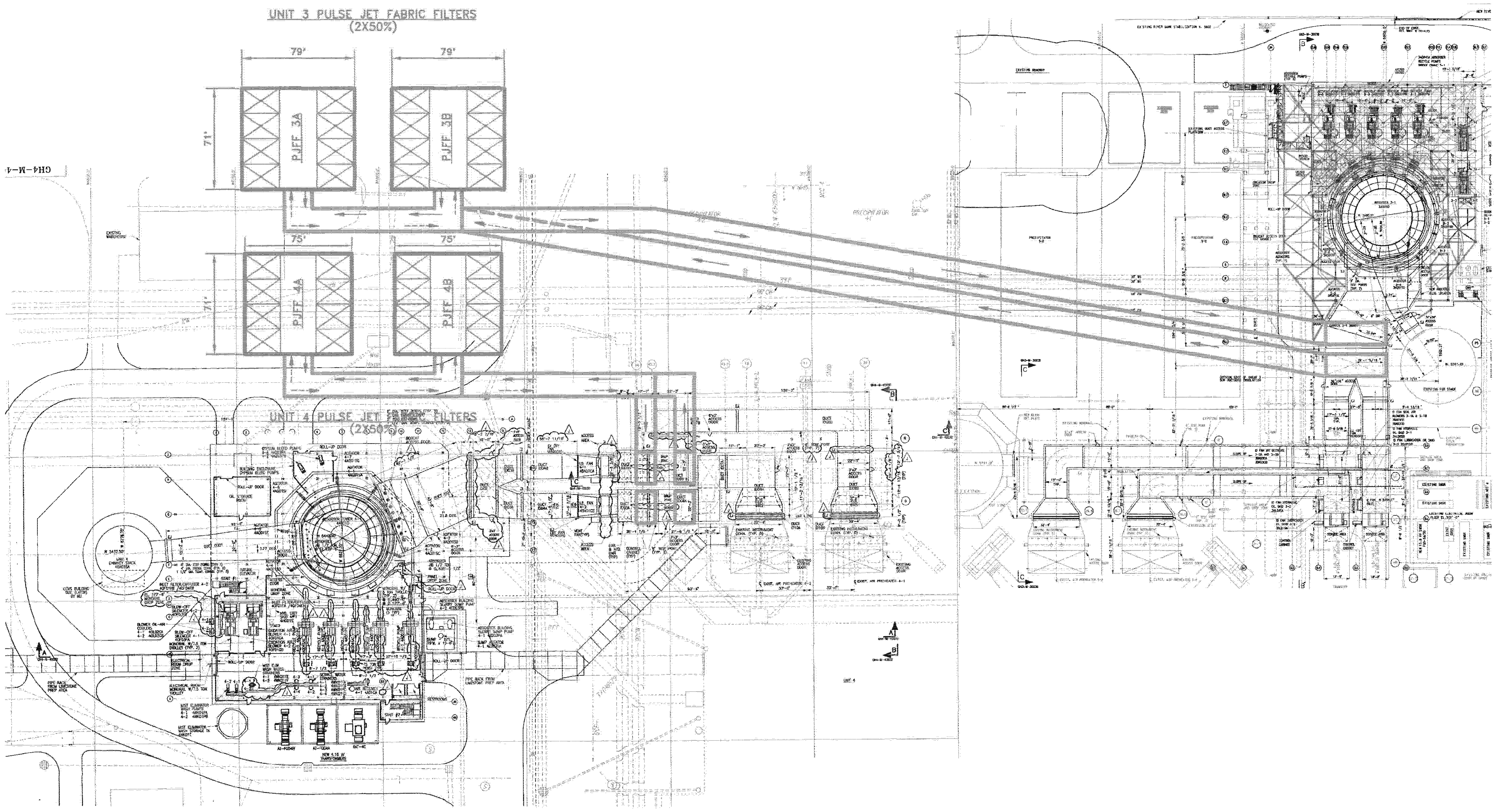
NEW DUCTWORK= ▬



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BLACK & VEATCH CORPORATION

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E.ON.
GHENT – UNITS 3 & 4
FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER 167987–CAQC–M1003
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CODE
AREA

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Cane Run

Cane Run Units 4, 5 & 6

Constructability Challenges

- Ingress from highways - Multiple power lines need to be raised to accommodate high loads.
- Barge unloading is not economically feasible.
- Existing overhead power lines are routed over ach unit and must be relocated for crane access.
- 4kv building and CT switchyard needs to be relocated.
- Entire unit #5 "back-end" must be dismantled prior to starting any work on unit #4.
- There is a need for multiple mob/demob/outages for tie-ins and access to build new AQCS equipment.
- Underground utility interferences/relocations.
- Above ground utility interferences/relocations.
- Need for areas to build ammonia storage, ASH handling systems, limestone handling, Reagant Prep, Dewatering (Ancillary Systems)
- Extended outages (entire plant) needed to accommodate construction of new AQCS Systems.
- Demolition must be performed in multiple phases followed by extensive earthwork activities to bring existing site up to proper elevation.
- Soils must be tested and stabilized for heavy lift crane operations.
- Space is very limited around units; the most efficient use of modularization will be compromised.

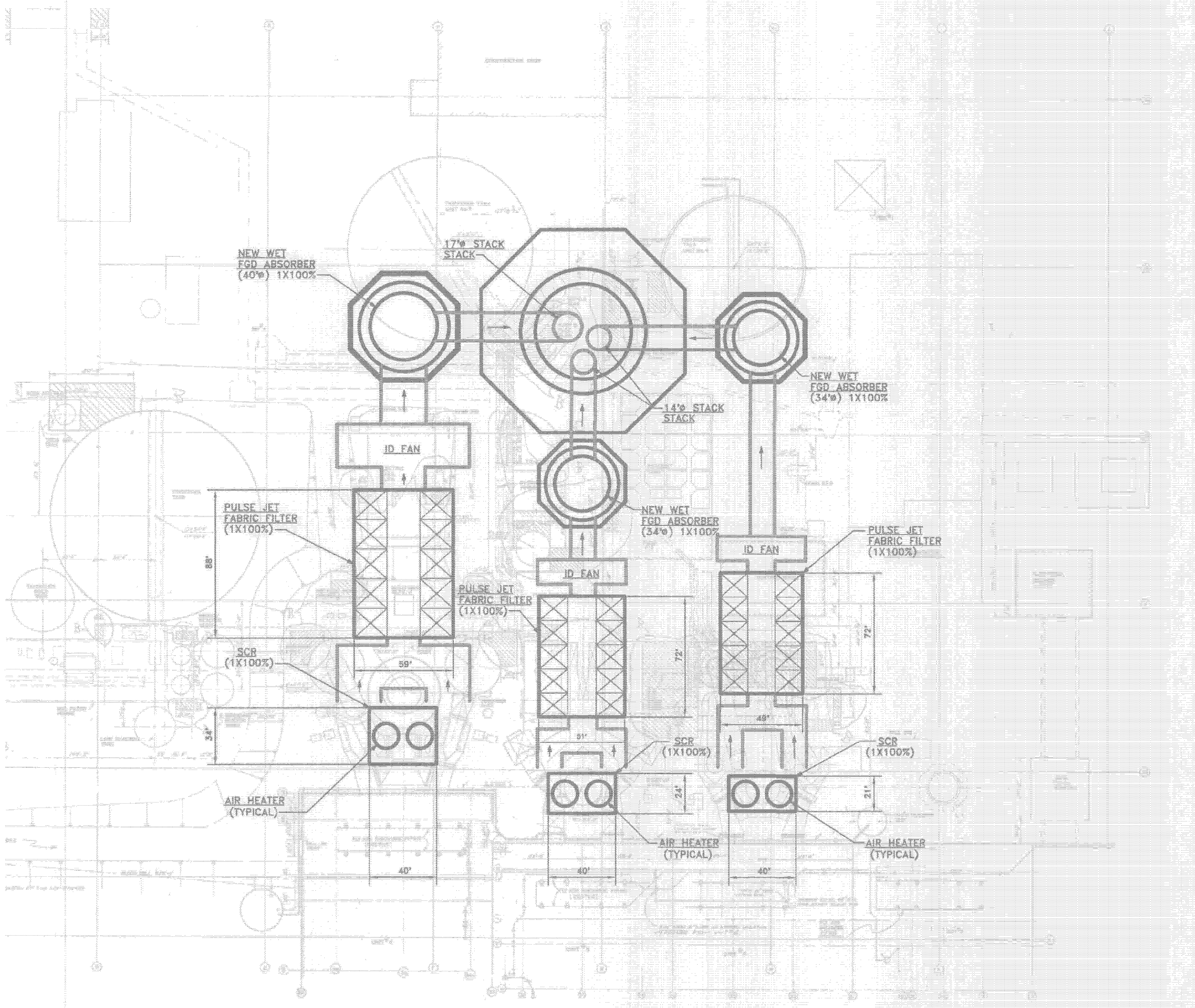
AQC Technology and Equipment

- Selective Catalytic Reduction
- Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization
- Stack
- Air heater

LEGEND:

NEW EQUIPMENT= ▬

NEW DUCTWORK= ▬



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1" =300'

BLACK & VEATCH
CORPORATION

ENGINEER
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E.ON.
CANE RUN UNITS 4, 5 & 6

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER
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AREA

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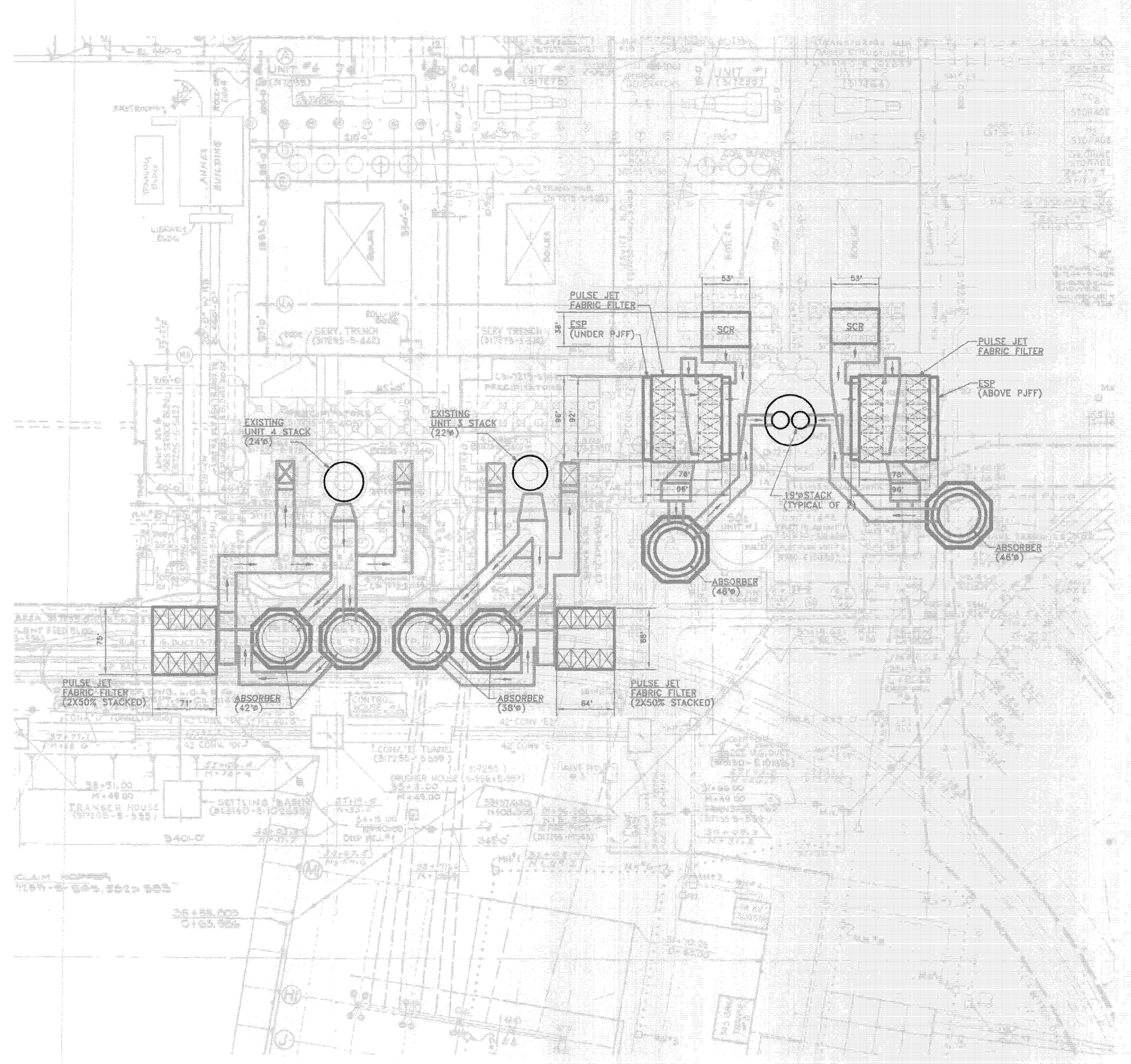
Mill Creek



Mill Creek Units 1, 2, 3 & 4

Constructability Challenges

- Real estate constraints for all the units.
- Unit 1 & Unit 2 ESP elevated.
- Unit 3 & Unit 4 PJFF (2x50%) stacked one above another.
- Barge unloading is not economically feasible.
- Overhead power lines and @ least 2 transmission towers must be moved.
- Numerous underground utility interferences/relocations
- Numerous above ground utility interferences/relocations
- Very limited access around units due to existing AQCS Systems.
- Multiple mob/demob (very selective) dismantling operations are needed to insure tie-in work is accomplished efficiently.
- Building between units 1 & 3 from unit #1 work will present logistical problems for both plant work and construction. Access/height restrictions will dictate the magnitude of modularization that can be utilized.
- Warehouse and loading dock on unit #2 side must be relocated.
- High complexity of ancillary systems routing to avoid interference with existing AQCS systems.
- Ground stability will need to be verified, modified to accommodate heavy lift cranes.
- Multiple plant outages will be needed for tie-ins because we are utilizing existing scrubbers, etc…through out project.
- Ductwork routing is more extensive due to the lay out of the existing plant and existing AQCS systems in use. Space will be a premium for excavations/foundations/duct steel erection.
- Large existing concrete foundations will need to be removed to accommodate equipment.
- Outage windows are very short and limited.
- Site constraints due to existing rail road tracks.

AQC Technology and Equipment Units 1 & 2

- Selective Catalyst Reduction.
- Electrostatic Precipitator and Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization

AQC Technology and Equipment Units 3 & 4

- Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization

LEGEND:
NEW EQUIPMENT=
NEW DUCTWORK=
EXISTING EQUIPMENT=

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1"=500'

BLACK & VEATCH CORPORATION

E.ON.
MILL CREEK UNITS 1, 2, 3 & 4

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

ENGINEER
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DATE

PROJECT
DRAWING NUMBER 167987-CAQC-M1008
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CODE
AREA

Trimble County

Trimble County Unit 1

Constructability Challenges

- Real estate constraints
- Elevated Pulse Jet Fabric Filter
- Extensive underground investigation will be required to identify operating utilities prior to installing new foundations
- An existing abandoned tower crane foundation and multiple runs of electrical duct bank cover a large percentage of the area within the footprint proposed to install foundations for the Unit 1 fabric filter support frame.

AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:
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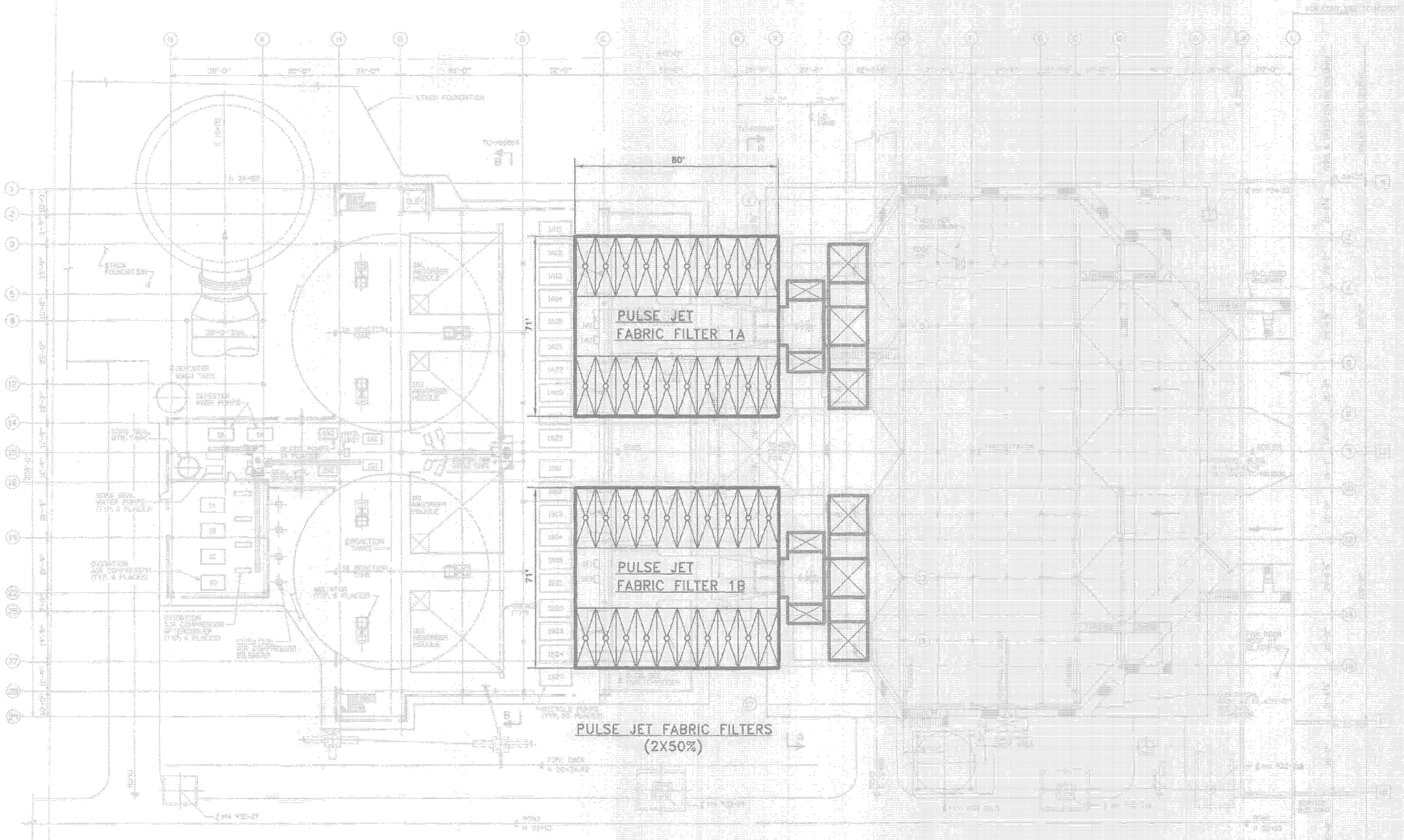
NEW DUCTWORK= ▬



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1"=200'

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CORPORATION

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E.ON.
TRIMBLE COUNTY UNIT 1

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER
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REV 0
CODE
AREA

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Green River

Green River Units 3 & 4

Constructability Challenges

- Overhead power lines and one tower needs to be relocated.
- Underground utility interferences/relocations
- Above ground utility interferences/relocations

AQC Technology and Equipment

- Selective Catalyst Reduction
- Circulating Dry Scrubber
- Pulse Jet Fabric Filter
- Stack
- Air Heater

LEGEND:

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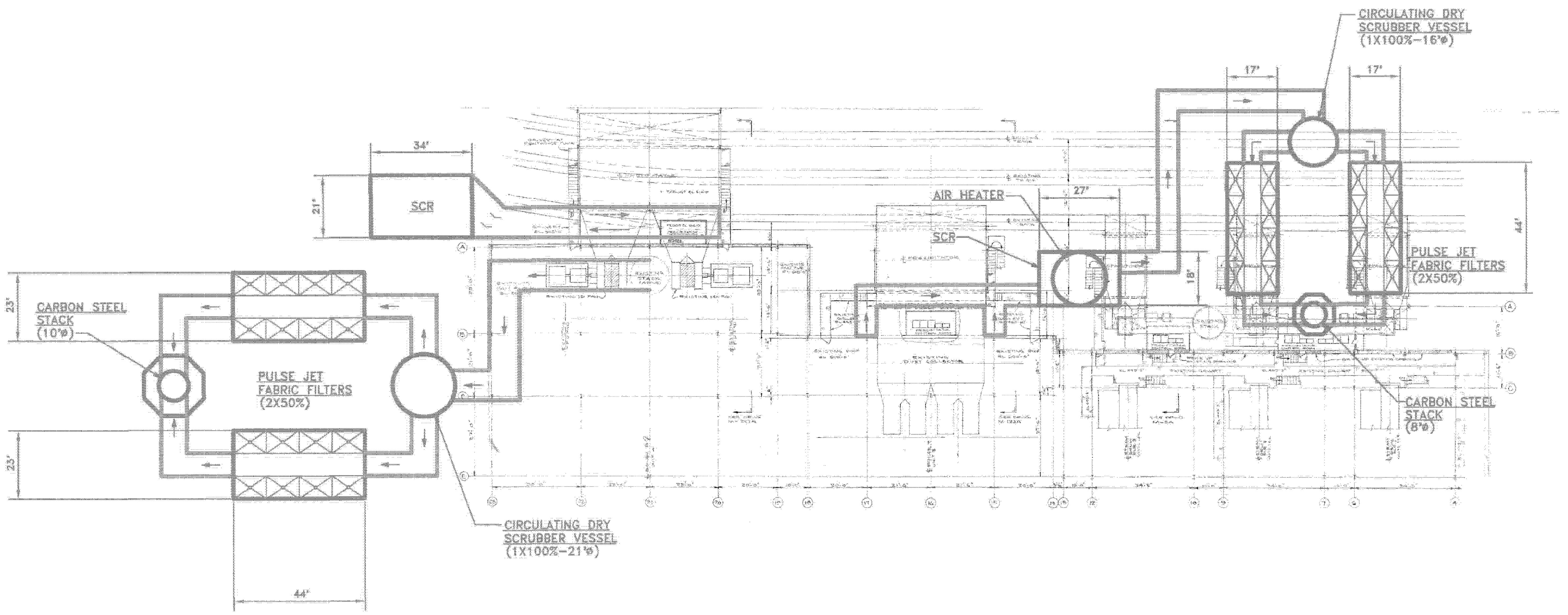
NEW DUCTWORK= ▬



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1"=200'

BLACK & VEATCH CORPORATION

ENGINEER
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DATE

E.ON.
GREEN RIVER UNITS 3 & 4

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER 167987-CAQC-M1007
REV 0
CODE
AREA

Appendix H
Air Quality Control Technology Costs

E.W. Brown

Plant Name: Brown
Unit: 1
MW 110
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
Fabric Filter	$40,000,000	$364	$1,477,000	$6,345,000
PAC Injection	$1,599,000	$15	$614,000	$809,000
Overfire Air	$767,000	$7	$132,000	$225,000
Low NOx Burners	$1,156,000	$11	$0	$141,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	$44,022,000	$400	$2,273,000	$7,631,000

BROWN UNIT 1 - PJFF COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$1,969,000	
Mechanical - Balance of Plant (BOP)	$5,641,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$119,000	
Control - DCS Instrumentation	$133,000	
ID Fans	$1,166,000	Engineering Estimates
Subtotal Purchase Contract	**$9,028,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$1,752,000	
Civil/Structural Construction - Sub-Structures	$666,000	
Mechanical/Chemical Construction	$6,664,000	
Electrical/Control Construction	$2,250,000	
Service Contracts & Construction Indirects	$109,000	
Demolition Costs	$5,000,000	Engineering Estimates
Subtotal Construction Contracts	**$16,441,000**	
Construction Difficulty Costs	**$11,508,700**	Engineering Estimates
Total Direct Costs	**$36,977,700**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$1,426,000	
EPC Construction Management (Includes G&A & Fee)	$933,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$141,000	
Sales Taxes	$50,000	
Project Contingency - 18%	$526,000	
Total Indirect Costs	**$3,076,000**	
Total Contracted Costs	$40,000,000	
Cost Effectiveness	*$364*	*/kW*

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	44%	
Maintenance labor and materials	$1,200,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$1,200,000**			
Variable Annual Costs				
Byproduct disposal	$6,000	210 lb/hr and	15	$/ton
Bag replacement cost	$91,000	2,740 bags and	100	$/bag
Cage replacement cost	$46,000	2,740 cages and	50	$/cage
ID fan power	$117,000	710 kW and	0.04266	$/kWh
Auxiliary power	$17,000	105 kW and	0.04266	$/kWh
Subtotal Variable Annual Costs	$277,000			
Total Annual Costs	$1,477,000			
Levelized Capital Costs	**$4,868,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$6,345,000			

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: PAC Injection

Date: 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$92,670	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$60,897	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$84,726	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$10,591	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$39,716	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$254,179	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$13,239	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$556,018				
Freight	$14,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$570,000				
Direct installation costs					
Foundation & supports	$57,000	(PEC) X	10.0%		
Handling & erection	$114,000	(PEC) X	20.0%		
Electrical	$57,000	(PEC) X	10.0%		
Piping	$29,000	(PEC) X	5.0%		
Insulation	$11,000	(PEC) X	2.0%		
Painting	$29,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$297,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$942,000				
Indirect Costs					
Engineering	$113,000	(DC) X	12.0%		
Owner's cost	$113,000	(DC) X	12.0%		
Construction management	$94,000	(DC) X	10.0%		
Start-up and spare parts	$14,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$188,000	(DC) X	20.0%		
Total indirect costs (IC)	$622,000				
Allowance for Funds Used During Construction (AFDC)	$35,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$1,599,000**				
Cost Effectiveness	***$15 /kW***				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$28,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$151,000				
Variable annual costs				44 %	capacity factor
Reagent (BPAC)	$445,000		105 lb/hr and	2200 $/ton	
Byproduct disposal cost	$3,000		105 lb/hr and	15 $/ton	
Auxiliary power	$15,000		90 kW and	0.04266 $/kWh	
Total variable annual costs	$463,000				
Total direct annual costs (DAC)	$614,000				
Indirect Annual Costs					
Cost for capital recovery	$195,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$195,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$809,000**				

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: Overfire Air System Operation **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Neuco NOx optimization package	$13,000	B&V cost estimate		
NOx monitoring equipment	$40,000	B&V cost estimate		
Water cannon system	$317,000	B&V cost estimate		
Subtotal capital cost (CC)	$370,000			
Freight	$19,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$389,000			
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$78,000	(PEC) X	20.0%	
Electrical	$58,000	(PEC) X	15.0%	
Piping	$8,000	(PEC) X	2.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$10,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$154,000			
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$543,000			
Indirect Costs				
Engineering	$54,000	(DC) X	10.0%	
Owner's cost	$11,000	(DC) X	2.0%	
Construction management	$27,000	(DC) X	5.0%	
Start-up and spare parts	$11,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$54,000	(DC) X	10.0%	
Total indirect costs (IC)	$207,000			
Allowance for Funds Used During Construction (AFDC)	$17,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$767,000			
Cost Effectiveness	*$7 /kW*			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance materials	$10,000	B&V cost estimate		
Maintenance labor	$14,000	B&V cost estimate, 6 man weeks/yr		
Total fixed annual costs	$24,000			
Variable annual costs				
Replacement power due to efficiency hit	$108,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh		
Total variable annual costs	$108,000			
Total direct annual costs (DAC)	$132,000			
Indirect Annual Costs				
Cost for capital recovery	$93,000	(TCI) X	12.17%	CRF
Total indirect annual costs (IDAC)	$93,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	$225,000			

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: Upgraded Low NOx Burners **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$602,000			
Subtotal capital cost (CC)	$602,000			
Freight	$30,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$632,000			
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$126,000	(PEC) X	20.0%	
Electrical	$63,000	(PEC) X	10.0%	
Piping	$0	(PEC) X	0.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$16,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$205,000			
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$837,000			
Indirect Costs				
Engineering	$84,000	(DC) X	10.0%	
Owner's cost	$17,000	(DC) X	2.0%	
Construction management	$42,000	(DC) X	5.0%	
Start-up and spare parts	$17,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$84,000	(DC) X	10.0%	
Total indirect costs (IC)	$294,000			
Allowance for Funds Used During Construction (AFDC)	$25,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$1,156,000**			
Cost Effectiveness	*$11 /kW*			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
N/A	$0	Similar annual costs as current LNB		
Total fixed annual costs	$0			
Variable annual costs				
N/A	$0	Similar annual costs as current LNB		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$0			
Indirect Annual Costs				
Cost for capital recovery	$141,000	(TCI) X	12.17%	CRF
Total indirect annual costs (IDAC)	$141,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$141,000**			

Plant Name:	Brown
Unit:	2
MW	180
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$92,000,000	$511	$3,278,000	$14,474,000
Fabric Filter	$51,000,000	$283	$1,959,000	$8,166,000
Lime Injection	$2,739,000	$15	$1,155,000	$1,488,000
PAC Injection	$2,476,000	$14	$1,090,000	$1,391,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	$148,715,000	$826	$7,532,000	$25,630,000

BROWN UNIT 2 - SCR COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$4,636,000	
Ductwork and Breeching	$3,580,000	
Mechanical - Balance of Plant (BOP)	$1,173,000	
Electrical - Equipment, Raceway	$1,339,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$468,000	
Control - DCS Instrumentation	$151,000	
Air Heater Modifications	$0	Engineering Estimates
ID Fans	$1,158,000	Engineering Estimates
Catalyst	$1,883,000	
Selective Catalytic Reduction System (Including Ammonia System)	$1,643,000	
Subtotal Purchase Contract	**$16,531,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$2,854,000	
Civil/Structural Construction - Sub-Structures	$742,000	
Mechanical/Chemical Construction	$8,971,000	
Electrical/Control Construction	$4,103,000	
Service Contracts & Construction Indirects	$14,331,000	
Demolition Costs	$6,500,000	Engineering Estimates
Subtotal Construction Contracts	**$37,501,000**	
Construction Difficulty Costs	**$26,250,700**	Engineering Estimates
Total Direct Costs	**$80,282,700**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$2,696,000	
EPC Construction Management (Includes G&A & Fee)	$1,691,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$444,000	
Sales Taxes	$627,000	
Project Contingency	$6,326,000	
Total Indirect Costs	**$11,784,000**	
Total Contracted Costs	**$92,000,000**	
Capital Cost Effectiveness	***$511***	***/kW***

ANNUAL COST

Capacity Factor = 62%

Fixed Annual Costs				
Operating labor	$123,000	1 FTE and	123,325	$/year
Maintenance labor & materials	$2,408,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$2,581,000**			
Variable Annual Costs				
Reagent	$309,000	215 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$186,000	940 kW and	0.03646	$/kWh
Catalyst replacement	$202,000	50 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$697,000**			
Total Annual Costs	**$3,278,000**			
Levelized Capital Costs	**$11,196,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$14,474,000**			

BROWN UNIT 2 - PJFF COSTS

CAPITAL COST

Purchase Contracts			
Civil/Structural	$2,646,000		
Mechanical - Balance of Plant (BOP)	$7,580,000		
Electrical - Equipment, Raceway, Switchgears, MCC	$161,000		
Control - DCS Instrumentation	$178,000		
ID Fans	$535,000	Engineering Estimates	
Subtotal Purchase Contract	**$11,100,000**		
Construction Contracts			
Civil/Structural Construction - Super Structures	$2,355,000		
Civil/Structural Construction - Sub-Structures	$895,000		
Mechanical/Chemical Construction	$8,956,000		
Electrical/Control Construction	$3,024,000		
Service Contracts & Construction Indirects	$146,000		
Demolition Costs	$5,000,000	Engineering Estimates	
Subtotal Construction Contracts	**$20,376,000**		
Construction Difficulty Costs	**$14,263,200**	Engineering Estimates	
Total Direct Costs	**$45,739,200**		
Indirect Costs			
Engineering Costs (Includes G&A & Fee)	$2,334,000		
EPC Construction Management (Includes G&A & Fee)	$1,527,000		
Startup Spare Parts (Included)	$0		
Construction Utilites (Power & Water) - Included	$0		
Project Insurance	$231,000		
Sales Taxes	$82,000		
Project Contingency - 18%	$860,000		
Total Indirect Costs	**$5,034,000**		
Total Contracted Costs	$51,000,000		
Cost Effectiveness	*$283*	*/kW*	

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	62%
Maintenance labor and materials	$1,530,000	(DC) X 3.0%	
Subtotal Fixed Annual Costs	**$1,530,000**		
Variable Annual Costs			
Byproduct disposal	$5,000	120 lb/hr and	15 $/ton
Bag replacement cost	$129,000	3,880 bags and	100 $/bag
Cage replacement cost	$65,000	3,880 cages and	50 $/cage
ID fan power	$200,000	1,010 kW and	0.03646 $/kWh
Auxiliary power	$30,000	150 kW and	0.03646 $/kWh
Subtotal Variable Annual Costs	$429,000		
Total Annual Costs	$1,959,000		
Levelized Capital Costs	**$6,207,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$8,166,000		

Brown Unit 2
180 MW
High Level Emissions Control Study

Technology: Lime Injection

Date: 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$133,800	From Previous Mill Creek BACT Study			
Short-term storage silo	$88,800	From Previous Mill Creek BACT Study			
Air blowers	$121,800	From Previous Mill Creek BACT Study			
Rotary feeders	$19,800	From Previous Mill Creek BACT Study			
Injection system	$80,400	From Previous Mill Creek BACT Study			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$526,800	From Previous Mill Creek BACT Study			
Instrumentation and controls	$25,200	From Previous Mill Creek BACT Study			
Subtotal capital cost (CC)	$996,600				
Freight	$45,000	(CC) X	4.5%		
Total purchased equipment cost (PEC)	$1,042,000				
Direct installation costs					
Foundation & supports	$104,000	(PEC) X	10.0%		
Handling & erection	$208,000	(PEC) X	20.0%		
Electrical	$104,000	(PEC) X	10.0%		
Piping	$52,000	(PEC) X	5.0%		
Insulation	$21,000	(PEC) X	2.0%		
Painting	$52,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$541,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$1,658,000				
Indirect Costs					
Engineering	$199,000	(DC) X	12.0%		
Owner's cost	$199,000	(DC) X	12.0%		
Construction management	$166,000	(DC) X	10.0%		
Start-up and spare parts	$25,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$332,000	(DC) X	20.0%		
Total indirect costs (IC)	$1,021,000				
Allowance for Funds Used During Construction (AFDC)	$60,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,739,000				
Cost Effectiveness	*$15 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$50,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$173,000				
Variable annual costs				62 %	capacity factor
Lime	$754,000		2,100 lb/hr and	132.19 $/ton	
Byproduct disposal cost	$208,000		2,400 lb/hr and	15 $/ton	
Auxiliary power	$20,000		100 kW and	0.03646 $/kWh	
Total variable annual costs	$982,000				
Total direct annual costs (DAC)	$1,155,000				
Indirect Annual Costs					
Cost for capital recovery	$333,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$333,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,488,000				

Brown Unit 2
180 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$151,641	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$99,650	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$138,643	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$17,330	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$64,989	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$415,930	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$21,663	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$909,847				
Freight	$23,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$933,000				
Direct installation costs					
Foundation & supports	$93,000	(PEC) X	10.0%		
Handling & erection	$187,000	(PEC) X	20.0%		
Electrical	$93,000	(PEC) X	10.0%		
Piping	$47,000	(PEC) X	5.0%		
Insulation	$19,000	(PEC) X	2.0%		
Painting	$47,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$486,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$1,494,000				
Indirect Costs					
Engineering	$179,000	(DC) X	12.0%		
Owner's cost	$179,000	(DC) X	12.0%		
Construction management	$149,000	(DC) X	10.0%		
Start-up and spare parts	$22,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$299,000	(DC) X	20.0%		
Total indirect costs (IC)	$928,000				
Allowance for Funds Used During Construction (AFDC)	$54,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$2,476,000**				
Cost Effectiveness	***$14 /kW***				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$45,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$168,000				
Variable annual costs				62 %	capacity factor
Reagent (BPAC)	$896,000		150 lb/hr and	2200 $/ton	
Byproduct disposal cost	$6,000		150 lb/hr and	15 $/ton	
Auxiliary power	$20,000		100 kW and	0.03646 $/kWh	
Total variable annual costs	$922,000				
Total direct annual costs (DAC)	$1,090,000				
Indirect Annual Costs					
Cost for capital recovery	$301,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$301,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,391,000**				

Plant Name:	Brown
Unit:	3
MW	457
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
Fabric Filter	$61,000,000	$133	$3,321,000	$10,745,000
PAC Injection	$5,426,000	$12	$2,330,000	$2,990,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	$67,426,000	$148	$5,751,000	$13,957,000

BROWN UNIT 3 - PJFF COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$4,628,000	
Mechanical - Balance of Plant (BOP)	$13,257,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$281,000	
Control - DCS Instrumentation	$312,000	
ID Fans	$1,930,000	Engineering Estimates
Subtotal Purchase Contract	**$20,408,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$4,118,000	
Civil/Structural Construction - Sub-Structures	$1,565,000	
Mechanical/Chemical Construction	$15,663,000	
Electrical/Control Construction	$5,289,000	
Service Contracts & Construction Indirects	$255,000	
Demolition Costs	$500,000	Engineering Estimates
Subtotal Construction Contracts	**$27,390,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$47,798,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$5,925,000	
EPC Construction Management (Includes G&A & Fee)	$3,877,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$586,000	
Sales Taxes	$209,000	
Project Contingency - 18%	$2,183,000	
Total Indirect Costs	**$12,780,000**	
Total Contracted Costs	$61,000,000	
Cost Effectiveness	*$133 /kW*	

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	57%
Maintenance labor and materials	$1,830,000	(DC) X 3.0%	
Subtotal Fixed Annual Costs	**$1,830,000**		
Variable Annual Costs			
Byproduct disposal	$11,000	290 lb/hr and	15 $/ton
Bag replacement cost	$588,000	17,630 bags and	100 $/bag
Cage replacement cost	$294,000	17,630 cages and	50 $/cage
ID fan power	$460,000	2,540 kW and	0.03624 $/kWh
Auxiliary power	$138,000	760 kW and	0.03624 $/kWh
Subtotal Variable Annual Costs	$1,491,000		
Total Annual Costs	$3,321,000		
Levelized Capital Costs	**$7,424,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$10,745,000		

EW Brown Unit 3
457 MW
High Level Emissions Control Study

Technology: PAC Injection

Date: 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$350,000	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$230,000	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$320,000	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$40,000	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$150,000	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$960,000	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$50,000	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$2,100,000				
Freight	$53,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$2,153,000				
Direct installation costs					
Foundation & supports	$215,000	(PEC) X	10.0%		
Handling & erection	$431,000	(PEC) X	20.0%		
Electrical	$215,000	(PEC) X	10.0%		
Piping	$108,000	(PEC) X	5.0%		
Insulation	$43,000	(PEC) X	2.0%		
Painting	$108,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,120,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,348,000				
Indirect Costs					
Engineering	$402,000	(DC) X	12.0%		
Owner's cost	$402,000	(DC) X	12.0%		
Construction management	$335,000	(DC) X	10.0%		
Start-up and spare parts	$50,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$670,000	(DC) X	20.0%		
Total indirect costs (IC)	$1,959,000				
Allowance for Funds Used During Construction (AFDC)	$119,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$5,426,000**				
Cost Effectiveness	***$12 /kW***				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$100,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$223,000				
Variable annual costs				57 %	capacity factor
Reagent (BPAC)	$2,060,000		375 lb/hr and	2200 $/ton	
Byproduct disposal cost	$14,000		375 lb/hr and	15 $/ton	
Auxiliary power	$33,000		180 kW and	0.03624 $/kWh	
Total variable annual costs	$2,107,000				
Total direct annual costs (DAC)	$2,330,000				
Indirect Annual Costs					
Cost for capital recovery	$660,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$660,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$2,990,000**				