COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY TO MODIFY ITS	**)**	
CERTIFICATE OF PUBLIC CONVENIENCE	**)**	**CASE NO.**
AND NECESSITY AS TO THE MILL CREEK	**)**	**2012-00469**
UNIT 3 FLUE-GAS DESULFURIZATION UNIT	**)**	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION
DATED NOVEMBER 20, 2012

FILED: November 30, 2012

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of November 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

7/21/2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of November 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

7/21/2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles**, being duly sworn, deposes and says he is the Vice President of Transmission and Generation Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
JOHN N. VOYLES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this ~~28~~ 29th day of November, 2012.
jnh 29th

______________________________(SEAL)
Notary Public

My Commission Expires:

7/21/2015

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 1

Responding Witness: John N. Voyles, Jr.

Q-1. Refer to the Application to Amend the Certificate of Public Convenience and Necessity ("CPCN"), dated October 25, 2012 ("October 25 Application"), page 3. LG&E maintains that either the rehabilitation of the Mill Creek Unit 4 wet flue-gas desulfurization ("WFGD") for Unit 3 or the new construction of a Unit 3 WFGD is required to comply with National Ambient Air Quality Standard ("NAAQS") 1-hour SO_2 emission requirements as a part of the State Implementation Plan for the non-attainment in Jefferson County. The NAAQS 1-hour SO_2 emission requirement is also referred to in the John N. Voyles, Jr. Testimony ("Voyles' Testimony") at page 6, lines 9-13. However, the Lonnie E. Bellar's Testimony ("Bellar's Testimony"), dated October 25, 2012, page 4, line 2-4, states that the new of WFGD for Mill Creek Unit 3 is required to meet the Mercury and Toxic Air Standards Rule.

a. Clarify which air quality standard applies to the WFGD project at Mill Creek Unit 3 and which air quality standard will have a direct impact on the project schedule.

b. What is the deadline for compliance with the NAAQS 1-hour SO_2 requirement and the State Implementation Plan?

A-1. There is no conflict between the Application, Bellar Testimony, and Voyles Testimony; as explained below, all are correct.

a. The WFGD will assure the continuous compliance with both the 1-hour SO_2 NAAQS and MATS rule. However, the primary driver requiring installation of a new WFGD is to meet the 1-hour SO_2 NAAQS. Kentucky has proposed that southwestern Jefferson County be classified as non-attainment for the 1-hour SO_2 NAAQS based on air monitoring results near the Mill Creek facility. Under this NAAQS, the non-attainment area must come into compliance by mid-2017.

The WFGD also ensures that this facility will meet the MATS surrogate acid gas emission limit of 0.20 pounds of SO_2 per mmBtu of heat input. Since the compliance date for the MATS is April 16, 2015 and with a one-year extension is April 2016, the MATS rule is an important driver for the required construction schedule.

b. A modified State Implementation Plan (SIP) is due to be submitted by Kentucky/Jefferson County to EPA by June 2013. The EPA will have one year to review and approve the proposed SIP revision, followed by a 3-year period for implementation. Thus, unless EPA provides additional time for implementation, the compliance date for the new 1-hour NAAQS would be June 2017. Since the Mill Creek Station is the primary emitter of SO_2 in Jefferson County, LG&E has no reason to believe that Kentucky will request, or that the EPA will provide, additional time for implementation.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

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Question No. 2

Responding Witness: John N. Voyles, Jr.

Q-2. Refer to Mr. Voyles Testimony, Exhibit JNV-1, page 5 of the Babcock Power Feasibility Assessment of the Mill Creek Unit 3 Gas Being Diverted to the Unit 4 WFGD System Upgrades, dated December 2, 2011. Please explain the Case 1 cost estimate of $32.5M and the Case 2 cost estimate of $35.2M and how they relate to the ECR estimate of $74M.

A-2. Case 1 and Case 2 were developed after the June 29, 2011 filing of the 2011 ECR Compliance Plan application.[1] Thus they are not comparable to the $74M. The report dated December 2, 2011 in Exhibit JNV-1 was developed after Babcock Power Environmental Inc. ("BPEI") conducted a more thorough inspection during a Unit 4 equipment outage in September 2011where it was determined that more extensive repairs were required to meet the performance goals. The estimates associated with Case 1 and Case 2 were strictly technology and process material costs (i.e., they did not include non-engineered material costs) and did not include construction cost associated with installation.

The original ECR estimate of $74M represented the full cost of the Unit 4 WFGD System Upgrade.[2] See the attached for details of the $74M cost estimate. The original ECR estimate was based on the Black and Veatch (B&V) April 2011 Phase II study, which included $60M for equipment costs, structural steel upgrades and construction. A portion of the basis for that $60M estimate was provided to B&V by BPEI (approximately $38M). The remaining $14M of the estimate included overheads, escalation and allocations for common facility costs.

[1] In the matter of: *Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00162).

[2] The $74M includes cost of removal which is not included in the $72.8M shown in the 2011 ECR Compliance Plan in Case No. 2011-00162.

MC Unit 3 ECR Cost

$ in thousands	Mill Creek 3 - FGD (U4 update and tie in)
B&V Cost Estimate (Note 1)	$60,032
Percent Allocate Common	$4,000
3.5% Overheads	$2,241
4% Escalation	$6,572
2011 ECR Filing	$72,845
Removal Not Included in 2011 ECR Filing	$1,602
Total Cost	$74,447

Note 1 -2011 ECR Compliance Plan, Exhibit JNV-2 Appendix F /A1 1.0 Cost Estimate /287165 A111~2

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
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Question No. 3

Responding Witness: John N. Voyles, Jr.

Q-3. Refer to Voyles Testimony, Exhibit JNV-2, Zachry New WFGD Estimate for Mill Creek Unit 3. Explain how the $132M estimate for the new Unit 3 WFGD was derived.

A-3. The basis for the $132M estimate for the new Unit 3 WFGD is Option A ($113,560,374) as shown in Exhibit JNV-2 on the detailed Zachry Mill Creek Unit WFGD Comparison table. In addition to the cost estimate for Option A, the rest of the estimate includes costs for Auxiliary Power impacts, Distributed Control Systems, Chimney Impacts, Balance of Plant, Overheads, Escalation, Spares and A&G costs (approximately $18M).

For the details of the $132M cost estimate, see (1) the attachment to the response to Question No. 17, (2) Exhibit JNV-2, page 1 of 1, table titled, "Mill Creek Unit 3 WFGD Comparison" and (3) the table following titled, "Zachry Industrial Incorporated Estimate Detail Option "A" Stebbins Tower.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 4

Responding Witness: John N. Voyles, Jr.

Q-4. Refer to Voyles Testimony at page 9, line 5. Provide the basis for the statement that the $132M estimate for a new WFGD at Mill Creek Unit 3 is "consistent with the cost of the other two WFGDs which Zachry is contracted for at Mill Creek".

A-4. In April 2012, LG&E awarded the purchase of the WFGD technology and the construction of the equipment associated with the Mill Creek Air Compliance Projects. The cost for the WFGD technology purchase was $42M for Units 1&2 and $37M for Unit 4. The current estimate for the Unit 3 WFGD technology is $45M and is based on BPEI's revised proposal for similar equipment. This estimate accounts for schedule and market changes since the award of the Unit 4 and combined Units 1&2 WFGDs. The construction costs for each Unit varies due to equipment sizing, foundation and structural steel layouts, ductwork and balance of plant lengths, and constructability issues.

The total estimated costs for procuring, engineering and constructing Unit 4 WFGD is $140 million, plus $11 million budgeted to cover potential contractor overruns allowed through the structure of the target price based EPC contract.

The Unit 1&2 WFGD is physically larger due to serving both units. The cost to construct the combined WFGD is estimated to be $191 million, plus $21 million budgeted to cover a portion of the potential contractor overruns as allowed by the structure of the target price based EPC contract.

Thus the values of $151M for Unit 4 WFGD and $212M for Unit 1&2 WFGD are consistent and comparable with the $132M Unit 3 WFGD estimate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 5

Responding Witness: John N. Voyles, Jr.

Q-5. Refer to Voyles Testimony at page 9, line 8.

a. Explain what is meant by Level 1 engineering accuracy. What percent accuracy does this imply? What level of contingency is included for this level estimate?

b. Did the $74M estimate for refurbishing the WFGD at Mill Creek Unit 4 have a Level 1 engineering accuracy? If not, what was the level of accuracy of that estimated cost which has now been increased by more than 50 percent?

c. At a Level 1 engineering accuracy, how accurate is the estimated cost of $132M to build a new WFGD for Unit 3?

A-5. a. **Level I** – Deliverables are outlined to a point that allows for a review of scope that has accuracies and projections of quantities typically in the +/- 20-30% range. This level of accuracy is inclusive of contingencies associated with material quantities, labor efficiencies, escalation and scope.

b. No, the $74M estimate was based upon a Pre-Level 1 (Conceptual) engineering estimate which means deliverables are outlined and essentially defined in order to assess the feasibility of a project and the business need to expend development dollars. The level of accuracy for this screening phase can be based on professional judgment and experience, historical values, or standard statistical analysis. See also the response to Question No. 8a.

c. The $132M estimate is reasonable for the intended purpose in the evaluation and is consistent with the contracted costs for the two other WFGD for Mill Creek. See also the response to Question No. 4.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 6

Responding Witness: John N. Voyles, Jr.

Q-6. Refer to Voyles Testimony at page 10, lines 14-16.

a. Provide a detailed explanation of the importance of LG&E receiving approval to modify the Mill Creek Unit 3 Certificate by January 18, 2013. Is there a specific contractual activity that drives this date?

b. The Company's analysis evaluated the consequences associated with a 6-month delay. What are the consequences if the Commission approval is not provided until one month later? Or three months later?

c. Can construction be expedited if a decision is delayed for a short period of time?

A-6. a. Yes. The critical path driving the need for approval in January 2013 is the engineering activities to support duct modeling that affects flow model studies for the project scope. The contract was awarded in October 2012 and design activities are planned for January 2013. These activities will need to proceed as planned in order to meet the start of the spring 2016 outage and still be compliant prior to the summer peak load period.

b. Any delay would prevent completion of the Unit 3 project prior to the compliance date (with 1-year extension) and the unit would not be available for peak load season during the summer of 2016. If the Unit 3 WFGD cannot be in service prior to the summer peak load season, as discussed in Exhibit JNV-3, arrangements would need to be made for additional summer capacity at a cost of $19 million and the WFGD would be placed in service during the fall 2016. It can be further complicated by the compliance activities from other utilities in the region which may limit the availability of replacement power. This will also not be apparent much before the MATS compliance date. Effectively, a 6-month delay in the in service of the Unit 3 WFGD would occur.

From a project implementation perspective, the consequences of a delay are as follows:

A one month delay:

- A delay of one month will affect the timing of plant arrangements and flow model studies which will impact detailed design of the ductwork.
- Plant arrangement and Flow model delays will result in delays to steel design, procurement, fabrication, and erection to support Unit 3 completion
- Plant arrangement and Flow model delays will result in delays in confirming long lead equipment (large fans & drives)

A three month delay (In addition to items listed in "one month delay"):

- BPEI's material and equipment firm prices are only valid until March 1, 2013. A Full Notice to Proceed of April 19th will put BPEI in a difficult negotiating position with their selected equipment suppliers. It will be difficult to get the venders to hold the firm prices quoted once the bid validity date expires. The C276 hastelloy material needs to be procured by BPEI and Stebbins by March 1, 2013 in order to ensure firm pricing.
- Fabrication and delivery of long lead electrical equipment (e.g. – switchgear) to support project completion is impacted.
- Fabrication and delivery of long lead controls systems (e.g. – DCS) to support project completion is impacted.
- The project will be unable to fully benefit from pricing efficiencies in the procurement of various components such as large valves
- There will be reduced ability to capitalize on planned unit outages for required reroutes of existing underground facilities.

c. No. Construction activities are already constrained by an outage in the beginning and end of Unit 3 site activities. The Unit 3 WFGD scope has resulted in compressed construction schedule for unit 3. Any delays affecting engineering and procurement that would cause construction to be further expedited cannot be absorbed in the current schedule. Also, there is a potential for inefficiencies resulting from additional delays given the planned common procurements.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 7

Responding Witness: John N. Voyles, Jr.

Q-7. Refer to Voyles Testimony at page 11, footnote 3. Explain in detail the reasons why it is not clear that LG&E will be able to obtain a second year extension. Explain the process involved in obtaining a second year extension.

A-7. The process to obtain a second year extension is explained in a December 16, 2011 memorandum from Cynthia Giles, Assistant Administrator of USEPA's Office of Enforcement and Compliance Assurance to EPA's Regional Administrators, Regional Counsel, Regional Enforcement Division Directors and Air Division Directors. See the attached memorandum. In this memo, EPA describes its intended approach for use of Clean Air Act Section 113(a) administrative orders to allow a source to operate in noncompliance with the MATS for up to one year to address a specific and documented electric reliability concern. It is EPA's intention that this policy will be limited to units that are critical for electric reliability purposes. Sources that qualify for the "broadly available one-year extension" obtained from their permitting authority (e.g., Kentucky Division for Air Quality) pursuant to Clean Air Act Section 112(i)(3)(B) (i.e., the first year extension) may also qualify for these administrative orders at the end of the first extension (i.e., the "second year" extension).

For identification and/or analysis of electric reliability risks, EPA will rely on the advice and counsel of electric reliability experts, including but not limited to, the Federal Energy Regulatory Commission, Regional Transmission Operators, Independent System Operators and other Planning Authorities, the North American Electric Reliability Corporation and affiliated regional entities, and state public services commissions and public utility commissions. EPA will work with these and other organizations to ensure that any claims of electric reliability risks are properly characterized and evaluated.

If a source has taken all steps necessary to comply with the MATS, but may still be needed to operate in noncompliance with the MATS to address concerns with electric reliability, an Administrative Order may be granted to allow a source to be brought into compliance with the MATS while being allowed to maintain operation. However, the Administrative Order would only be issued on or after (not before) the MATS Compliance Date and would be limited to units that are required to run for electric reliability purposes that (a) would otherwise be deactivated, or (b) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay.

As described above and in the attached, the process to obtain a second year extension is an arduous one and is not finalized until after the MATS Compliance Date. For these reasons, it is unclear whether LG&E is able to obtain a second year extension.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

December 16, 2011

MEMORANDUM

SUBJECT: **The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard**

FROM: **Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance** Cynthia Giles

TO: **Regional Administrators (EPA Regions I-X)**
Regional Counsel (EPA Regions I-X)
Regional Enforcement Division Directors (EPA Regions I-X)
Air Division Directors (EPA Headquarters and Regions I-X)

I. STATEMENT OF POLICY

It is the EPA's obligation to ensure compliance with environmental laws designed to protect public health and welfare. Where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare.

Pursuant to Section 112 of the Clean Air Act ("CAA"), the EPA finalized national emission standards for hazardous air pollutants ("NESHAP") from electric generating units ("EGUs") in December 2011. These standards, commonly known as the "Mercury and Air Toxics Standards" ("MATS"), adopt emission limits on mercury, acid gases and other toxic pollutants for affected coal and oil-fired EGUs. Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies.

The EPA believes that all affected sources will be able to comply with the MATS within the compliance period specified by Section 112(i)(3) of the CAA (including, as applicable, any extensions permitted under Section 112(i)(3)(B)) (the "MATS Compliance Date"). The EPA's analysis projects only a modest level of retirements, and the Agency does not anticipate that such retirements will lead to resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit or a delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability that cannot be predicted or planned for with specificity at the present time. In such instances, sources could find themselves in the position of either operating in noncompliance with the MATS or halting operations and thereby potentially impacting electric reliability.

The EPA is issuing this policy memorandum to describe its intended approach regarding the use of Section 113(a) administrative orders ("AOs") with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented reliability concern. This enforcement policy is limited in application to units that are critical for reliability purposes. Some sources will be able obtain a broadly available one-year extension pursuant to Section 112(i)(3)(B). A source that qualifies for a one year extension from its permitting authority may also qualify for an AO at the end of its extension, provided that it falls within the terms of this policy. The EPA believes that there are likely to be few, if any, cases in which it is not possible to mitigate a reliability issue within four years, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under this policy.

This policy does not address situations where a reliability critical unit needs more than one year to come into compliance after the MATS Compliance Date. The policy also does not address delays in installations of controls and/or other instances of noncompliance with the MATS for units that are not reliability critical. The EPA intends to handle such scenarios as it has in the past, by assessing each situation on a case-by-case basis, at the appropriate time, to determine the appropriate enforcement response and resolution.

As set forth below, in light of the complexity of the electric system and the local nature of many reliability issues, the EPA will, for purposes of using its Section 113(a) AO authority in this context, rely for identification and/or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ("FERC"), Regional Transmission Operators ("RTOs"), Independent System Operators ("ISOs") and other Planning Authorities as identified herein, the North American Electric Reliability Corporation ("NERC") and affiliated regional entities, and state public service commissions ("PSCs") and public utility commissions ("PUCs"). The EPA will work with these and other organizations, as appropriate, to ensure that any claims of reliability risks are properly characterized and evaluated.

The EPA is committed to achieving compliance with the MATS while ensuring electric reliability.

The policies established in this document supplement other applicable policies, and are intended to assist government personnel in determining the appropriate response to noncompliance. These policies and procedures are not intended to, nor do they, constitute a rulemaking by the EPA. These policies and procedures do not create a right or a benefit, substantive or procedural, that is enforceable at law or in equity by any person. The EPA reserves the right to act at variance with these policies and to change them at any time without public notice. Further, nothing in this document should be construed to affect the EPA's analysis of, or reaction to, an imminent and substantial endangerment to human health.

II. SUMMARY OF LEGAL REQUIREMENTS AND AUTHORITIES

Section 112 of the CAA establishes compliance deadlines for existing sources to meet standards promulgated under that provision, such as those included in the MATS rule.[1] Specifically, Section 112(i)(3)(A) provides:

> After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard.
>
> *See, also* 40 CFR 63.9984.

The CAA and its implementing regulations provide specific conditions under which extensions may be granted to this three year compliance period and under which other compliance time periods may apply. *See, e.g.,* Section 112(i)(3)(B), (4)-(6). In particular, Section 112(i)(3)(B) provides:

> The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls.

Section 113 of the CAA authorizes the Administrator to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated

[1] Except as otherwise provided under Section 112(i)(3)(B), the MATS requires compliance within three years of the effective date, the statutory maximum.

resolutions including, for example, expeditious compliance schedules with enforceable compliance milestones.

III. THE EPA'S ENFORCEMENT RESPONSE TO BRING RELIABILITY-CRITICAL UNITS INTO COMPLIANCE

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). This policy describes the EPA's intended enforcement response in such instances. The policy is informed, as are our enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response.

Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO to bring a source into compliance within one year. *See* Section 113(a). Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limited to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay.[2]

The Agency is cognizant that early planning will play a key role in allowing for the identification, and timely mitigation, of any potential reliability issues. The EPA expects that owners/operators will begin compliance planning early, and will provide early notice of their compliance plans to the appropriate reliability entities. We further expect that entities with responsibility for reliability planning and coordination will develop and maintain system-wide reliability plans for the units within their purview, and that this regional reliability planning will provide early identification of units that are critical for reliability purposes. Early notice and planning can discourage delays in coming into compliance, encourage timely action to avoid or mitigate reliability concerns, and minimize the need for issuance of AOs of the type described herein.

[2] The EPA does not intend to seek civil penalties for violations of the MATS that occur as a result of operation for up to one year in conformity with an AO issued in connection with this policy, unless there are misrepresentations in the materials submitted in a request for an AO.

The EPA also recognizes the need for advance planning with regard to the future availability of any reliability critical EGUs to operate as needed to maintain electric reliability. Accordingly, although an AO cannot be issued under Section 113(a) prior to the MATS Compliance Date, the EPA intends – where the owner/operator has timely submitted a complete request and has provided appropriate cooperation – to give the owner/operator as much advance written notice as practicable of the Agency's plans with regard to such an AO.

To qualify for an AO in connection with this policy, an owner/operator should, at a minimum, take the following steps.[3, 4]

A. Provide early notice of compliance plans. Within one year after the effective date of the MATS, an owner/operator should provide written notice of its compliance plans, with regard to each EGU it owns or operates, that identifies (a) the units it plans to deactivate and the anticipated dates of deactivation and (b) the units for which it intends to install pollution control equipment or otherwise retrofit and the anticipated schedule for completion of that work, to the Planning Authority for the area in which the relevant EGU or EGUs are located.[5]

B. Timely request an AO for a unit that may affect reliability due to deactivation. In addition to the elements identified in III(A) above, for a unit that is required to run for reliability purposes that would otherwise be deactivated:

   1. An owner/operator should, no less than 180 days prior to the MATS Compliance Date, submit electronically to (a) the Director of the Air Enforcement Division in the EPA's Office of Enforcement and Compliance Assurance, and (b) the Regional Administrator of the EPA Region in which the EGU is located, with a copy to FERC, at an office of its designation, (collectively, "AO Request Recipients") a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to each of the elements specified in III(D) below.

   2. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to (a) the Planning Authority, (b) any state PUCs/PSCs with regulatory jurisdiction with

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[3] The EPA will evaluate each request for an AO for a unit that is required to run for reliability purposes on a case-by-case basis.

[4] Any notice, request or other submission discussed in this memorandum should conform to the standard business practice of the receiving entity for the submission of information, including any requirements governing submission of Confidential Business Information and/or other confidential information.

[5] Planning Authority is the entity defined as such in the "Glossary of Terms Used in NERC Reliability Standards," available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf, or any successor term thereto approved by FERC, and includes, in relevant jurisdictions, RTOs and ISOs.

regard to the relevant EGU,[6] (c) any state, tribal or local environmental agency with permitting authority under Titles I and V of the CAA, and any tribal environmental agency that does not have such authority, with jurisdiction over the area in which the EGU is located (collectively, "AO Notice Recipients").

C. Timely request an AO for a unit that may affect reliability due to delays related to the installation of controls. In addition to the elements identified in III(A) above, for a unit that that is required to run for reliability purposes that, due to factors beyond the control of the owner/operator, has a delay in installation of controls or needs to operate because another unit has had such a delay:

1. An owner/operator should, within a reasonable time of learning of a delay that it believes may result in a unit being unable to comply by the MATS Compliance Date, provide to the Planning Authority for the area in which the relevant EGU or EGUs are located, written notice of the units impacted by the delay, the cause of the delay, an estimate of the length of time of the delay, and the timeframe during which it contemplates operation in noncompliance with the MATS.

2. An owner/operator should, within a reasonable time of learning that it is critical to reliability to operate a unit described in the preceding paragraph in noncompliance with the MATS after the MATS Compliance Date, submit electronically to the AO Request Recipients a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to as many of the elements specified in III(D) below as it is possible to provide at that time.

3. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to the AO Notice Recipients.

D. Submit a complete request for an AO. The following elements should be included in a request for an AO in connection with this policy:[7]

1. Copies of the early notice provided to the Planning Authority pursuant to III(A) or an explanation of why it was not practicable to have provided such notice and a demonstration that such notice was provided as soon as it was practicable.

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[6] PUCs/PSCs may also wish to obtain the information identified in III(A), either by requesting that an owner/operator over which the PUC/PSC has jurisdiction provide such information directly, or by requesting such information from the relevant Planning Authority.

[7] The EPA may request additional information from the unit owner/operator. The speed with which the EPA evaluates a request and its ultimate response will be related to the timeliness, completeness, and quality of the submittal.

2. Written analysis of the reliability risk if the unit were not in operation, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with FERC, and, in the case of the Electric Reliability Council of Texas ("ERCOT"), with the Texas PUC,[8] or (b) cause reserves to fall below the required system reserve margin.

3. Written concurrence with the analysis in III(D)(2) by, or a separate and equivalent analysis by, the Planning Authority for the area in which the relevant EGU or EGUs are located, or, in the alternative, a written explanation of why such concurrence or separate and equivalent analysis cannot be provided, and, where practicable, any related system wide analysis by such entity.

4. Copies of any written comments from third parties directed to, and received by, the owner/operator in favor of, or opposed to, operation of the unit after the MATS Compliance Date.

5. A plan to achieve compliance with the MATS no later than one year after the MATS Compliance Date, and, where practicable, a written demonstration of the plan to resolve the underlying reliability problem and the steps and timeframe for implementing it, which demonstrates that such resolution cannot be effected on or before the MATS Compliance Date.

6. An identification of the level of operation of the unit that is required to avoid the documented reliability risk in III(D)(2) and, consistent with that level, a proposal for operational limits and/or work practices to minimize or mitigate any HAP emissions to the extent practicable during any operation not in full compliance with the MATS.

In evaluating a request for an AO submitted in contemplation of this policy, although the EPA's issuance of an AO is not conditioned upon the approval or concurrence of any entity, the EPA intends to consult, as necessary or appropriate on a case-by-case basis, with FERC and/or other entities with relevant reliability expertise.

[8] Because ERCOT oversees intrastate transmission of electricity solely within Texas and does not provide for interstate transmission, ERCOT files reliability criteria with the Texas PUC.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 8

Responding Witness: John N. Voyles, Jr.

Q-8. Refer to Exhibit JNV-3 at page 2, Table 1.

a. Provide support for the $161M estimate from the Babcock 2012 Update for the WFGD. Indicate specific references in the Babcock report that support the revised estimate.

b. Provide detailed support for the reduced baghouse capital cost estimate of $113M.

A-8. a. The December 2, 2011 report in Exhibit JNV-1 from BPEI included an estimate to engineer and procure engineered materials to upgrade the Unit 4 WFGD as described in Case 1 for a cost of $32,521,895 (see the attachment to Exhibit JNV-1 titled "Budget Engineering and Procurement Estimate", beginning at page 5 of 7). Subsequent to the report, BPEI answered an inquiry from Project Engineering to provide installation costs for the upgrades detailed in their report. See the attached BPEI June 20, 2012 report being provided under seal pursuant to a petition for confidential treatment. BPEI estimated the installation costs to be $37M (see page 6 of 7 in the attached report). The estimated direct cost from BPEI for engineering, procuring and installing the engineered equipment totaled $70M.

BPEI's report did not include an estimate for the balance of plant work that was required in support of the upgrade such as structural steel modifications/refurbishment, electrical power upgrades, electrical cable, conduit and cable tray replacement, painting, pipe replacement and other balance of plant components that are not in a condition to provide the desired twenty (20) plus years of useful life. Approximately $33M was needed for Balance of Plant scope, FGD foundations, instrument and electrical work, ductwork improvements, balance of plant structural steel replacements and HVAC.

In order to complete the refurbishment scope, additional work would be required to refurbish the reaction tank, balance of plant pipe, heat tracing, substantial repairs/replacement of ID Fan and ESP ductwork, auxiliary power upgrades for the new equipment, as well as segregation of water flow to facilitate dewatering for a different chemistry than the other two new WFGDs. Lastly, stack impacts as well as spare parts, balance of plant engineering, overheads, labor, escalation and A&G affect the total estimate. These components add approximately $58 million to the total estimated cost.

The total estimated cost of $161M is the sum of the $70M, $33M and $58M numbers discussed above. See the response to Question No. 17 for details on the $161M estimate.

b. The reduced baghouse cost is primarily driven by the reduced cost of the technology as awarded to Zachry. The referenced $113 million for the baghouse includes only the direct estimated cost for the EPC contractor and does not include Owner's costs. The total with Owner's cost is $127 million plus another $11 million has been budgeted to cover a portion of the potential contractor overruns as allowed by the target priced structure of the EPC contract.[3]

[3] The $113 million cost for the baghouse was used in all scenarios evaluated in Exhibit JNV-3

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 9

Responding Witness: John N. Voyles, Jr.

Q-9. Refer to Exhibit JNV-3 at page 3, Table 2. Provide detailed support for the $132M estimate from the Zachry 2012 Update for a new WFGD at Mill Creek Unit 3. Indicate specific references in the Zachry report that supports the estimate.

A-9. See the response to Question No. 3.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 10

Responding Witness: John N. Voyles, Jr.

Q-10. Refer to Exhibit JNV-3 at page 3, Table 3. Provide detailed support for the reduced variable and fixed O&M expenses for the baghouses.

A-10. The information provided in Table 3 highlights the updated cost projections resulting in a reduction of variable material consumption costs of approximately 47% and fixed operational costs of approximately 50%. The per-unit cost for the sorbent material remained the same as the original projection. However, the variable material cost update was driven by the ability to utilize much more detailed system based reagent consumption rates (pounds per hour) after further engineering was completed with the selected vendor for the PJFF systems. The revised usage level and resulting costs for the activated carbon reagent used in the process was lowered for all new PJFF systems across the fleet at a level similar to Mill Creek Unit 3 highlighted in Table 3.

The fixed operational costs were revised to remove the original estimates for bag and cage replacements which were annualized and included as part of the ongoing operational costs. Those items were approximately half of the fixed O&M estimate. The replacements for bags and cages will be treated as Capital based on the expected life of the equipment.[4] The current plan calls for a 3 year schedule for replacement.

[4] The capital cost associated with the future replacement of bags and cages was not included in the analysis contained in Exhibit JNV-3.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 11

Responding Witness: Charles R. Schram

Q-11. Refer to Exhibit JNV-3 at page 4, Table 6. Provide all support including electronic files that support the Net Present Value of Revenue Requirements ("NPVRR") values presented in the columns titled "Retrofit Mill Creek 3."

A-11. Please see the attachments being provided in Excel format. Certain information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment. These files were used in the original analysis; only the assumptions associated with the proposed amended plan have been changed.

The attachment is being provided in 2 separate files in Excel format and in multiple files Confidentially on CD.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 12

Responding Witness: John N. Voyles, Jr.

Q-12. Refer to Amended Application, Exhibit 1. Provide an update to the two page Exhibit using current estimates of both capital, operation, and maintenance costs assuming a new WFGD is constructed at Mill Creek Unit 3.

A-12. See the attached. The updated exhibit reflects the current estimates of capital, operation and maintenance costs for the full scope of the Mill Creek and Trimble County Air Compliance projects. In addition, the exhibit has been modified to exclude the SCR turndown projects removed due to the Cross State Air Pollution Rule ("CSAPR") being vacated by the U.S. Court of Appeals for the D.C. Circuit order issued on August 21, 2012.

LOUISVILLE GAS AND ELECTRIC COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Environmental Regulation	Environmental Permit*	Actual or Scheduled Completion	Actual (A) or Estimated (E) Projected Capital Cost ($Million)
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	Clean Air Act (1990), NAAQS and HAPS	Title V Permit	2015	$187.66 (E)
			Mill Creek Unit 2			2015	$187.66 (E)
			Mill Creek Unit 3			2016	$279.71 (E)
			Mill Creek Unit 4			2014	$267.17 (E)
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	Clean Air Act (1990) and HAPS	Title V Permit	2015	$118.14 (E)
							$1,040.33

LOUISVILLE GAS AND ELECTRIC COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Estimated Annual Operations and Maintenance Costs (Through 2020)								
				2012	2013	2014	2015	2016	2017	2018	2019	2020
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, SCR Turn-down (Unit 3 & 4), and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	$ -	$ -	$ -	$ 2,735,430	$ 4,822,734	$ 4,958,827	$ 5,097,642	$ 5,239,234	$ 5,383,657
			Mill Creek Unit 2	$ -	$ -	$ -	$ 2,834,115	$ 4,987,210	$ 5,118,512	$ 5,252,439	$ 5,389,046	$ 5,528,384
			Mill Creek Unit 3	$ -	$ -	$ -	$ -	$ 5,143,811	$ 8,994,321	$ 9,174,208	$ 9,357,692	$ 9,544,846
			Mill Creek Unit 4	$ -	$ -	$ 837,470	$ 10,250,633	$ 10,455,645	$ 10,664,758	$ 10,878,053	$ 11,095,614	$ 11,317,527
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	$ -	$ -	$ -	$ 348,587	$ 4,266,705	$ 4,352,039	$ 4,439,080	$ 4,527,862	$ 4,618,419

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
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Question No. 13

Responding Witness: John N. Voyles, Jr. / Lonnie E. Bellar

Q-13. Refer to the October 25 Application, page 4, which states that, "LG&E is also proposing to demolish the existing WFGD at Unit 4 to provide space for the new WFGD."

a. Explain how the cost to demolish the existing WFGD at Unit 4 is considered in the cost estimate.

b. Explain whether LG&E is seeking Commission approval for this demolition cost.

A-13. a. The cost to demolish the existing WFGD at Unit 4 is not included in the capital expenditures proposed for recovery through the ECR mechanism. However, those costs are included for planning, budgeting and evaluation purposes.

b. LG&E is not seeking Commission approval to include the cost to demolish the existing WFGD at Unit 4 through the ECR mechanism. Cost of removal is included in the Company's depreciation rates and excluded from the capital costs included for recovery through the ECR mechanism.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

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Question No. 14

Responding Witness: John N. Voyles, Jr.

Q-14. Refer to the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony"), page 3, lines 8-12. It states the following:

> LG&E has obtained further engineering studies and cost estimates showing that rehabilitating the existing Mill Creek Unit 4 WFGD to serve Mill Creek Unit 3 will be significantly more expensive than initially estimated: $161 million in estimated capital cost rather than $74 million. Building a new WFGD for Mill Creek Unit 3 will have an estimated capital cost of $132 million.

Provide a detailed comparison and explanation of the initial $74M estimate for rehabilitating Unit 4 versus the current $161M estimate.

A-14. For the reasons discussed in the responses to Question Nos. 2 and 8, the $74 million and $161 million estimates are not comparable.

The ECR estimate of $74M represented the full cost of the Unit 4 WFGD System Upgrade at the level of accuracy (Pre-Level I) at the time of filing.[5] The original ECR estimate was based on the Black and Veatch (B&V) April, 2011 Phase II study, which included $60M for equipment costs, structural steel upgrades and construction. A portion of the basis for that $60M estimate was provided to B&V by BPEI (approximately $38M). The remainder of the estimate, $14M, included overheads, escalation and allocations for common facility costs.

[5] The $74M includes cost of removal which is not included in the $72.8M shown in the 2011 ECR Compliance Plan in Case No. 2011-00162.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

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Question No. 15

Responding Witness: John N. Voyles, Jr.

Q-15. Refer to the Supplemental Voyles Testimony, page 4 where it states that:

> Because of the importance of having the assurance of ECR recovery to LG&E's ability to spend over $31 million next year just for Mill Creek Unit 3, and to commit to $136 million in financial obligations to build the proposed new WFGD for Unit 3, LG&E asks the Commission to issue a Final Order in this proceeding by January 18, 2013.

Explain the difference between the $132M estimated capital costs for Unit 3 WFGD and the $136M in financial obligations to build the proposed new WFGD for Unit 3.

A-15. The $136 million noted in Voyles Testimony, page 4 includes commitments of $132 million for the Mill Creek 3 WFGD plus $4 million in ductwork, structural steel, and electrical cable and conduit quantity changes due to the proposed change in location for the baghouse.

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 16

Responding Witness: John N. Voyles, Jr.

Q-16. Refer to the Voyles Testimony, page 5, which states, "[in] addition, LMAPCD monitors and measures throughout Jefferson County the concentration of pollutants under the NAAQS, including ozone (O_3), carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2) and nitric oxide (NO), inhalable particulates (PM10), fine particulates (PM2.5) and lead (Pb)." Provide a comparison of the estimated change in emissions for the pollutants listed above for Units 3 and 4 as a result of the proposed changes in the environmental compliance plan from the 2011 Environmental Compliance Plan[6] to the current proposed plan.

A-16. The construction of a new FGD for Mill Creek Unit 3 is expected to provide up to an additional 2% removal of SO_2 (i.e. 97% to 99%) beyond the previously approved refurbishment project. The additional removal of SO_2 is equivalent to approximately 74 tons per year. Although a specific amount would be difficult to estimate, the improved performance with the proposed new vertical tower FGD would also provide additional reductions in PM, PM_{10} and Sulfuric Acid Mist.

There are no emissions changes expected from the previously submitted control plans for Mill Creek Unit 4.

[6] Case No. 2011-00162, *Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge* (Ky. PSC Dec. 15, 2011).

LOUISVILLE GAS AND ELECTRIC COMPANY

Case No. 2012-00469

Response to Commission Staff's First Request for Information
Dated November 20, 2012

Question No. 17

Responding Witness: John N. Voyles, Jr. / Charles R. Schram

Q-17. Refer to the Voyles Testimony, pages 7-9.

a. Provide a detailed comparison and explanation of Babcock's $161M estimate for rehabilitating Unit 4 to serve Unit 3 versus Zachry's $132M estimate to build a new WFGD at Unit 3.

b. Identify and explain the effect(s) on the net auxiliary power from the original plan to the proposed amended plan and how any changes were factored into the NPVRR savings.

A-17. a. See the attachment and the responses to Question Nos. 4, 8 and 14.

b. The proposed amended plan analysis did not include changes to the auxiliary power inputs as such changes are not considered to be material. The Companies continued to model an additional 1 MW of auxiliary power for the FGD and 5 MW of auxiliary power for the baghouse, for a total of 6 MW, as presented in Table 78 of Exhibit CRS-1 to the 2011 ECR filing.

MC3 WFGD Options -- Refurbishment versus New Build Order Of Magnitude Estimate

Item	Date of Estimate ($ x $1,000)	8/1/2012	9/25/2012
		Case 2 Option (Refurb.)	**Revised ZHI Option A**
1	WFGD Island Per BPEI (Technology/Material Contract)	$32,522	$44,624
2	Installation of BPEI WFGD Technology	$37,213	$68,936
3	BOP Demolition	$3,000	incl.
4	WFGD Foundations	$3,000	incl.
5	I and E	$3,000	incl.
6	Wet/Dry 686 Duct	$2,200	$0
7	Outlet Duct Above Modules	$1,100	$0
8	Inlet Duct, Found, Steel, and Insulation From #3 ID Fans	$6,000	incl.
9	Outlet Ductwork WFGD - Stack (Foundation and Steel Required for New Option)	$4,000	incl.
10	BOP Structural Steel	$8,000	incl.
11	Buildings, Siding, & HVAC	$3,000	incl.
12	Reaction Tank Repair	$2,000	$0
13	BOP Pipe and Mechanical	$2,000	incl.
14	Heat Trace and Pipe Insulation	$2,000	incl.
15	Segregation of Water Flows	$3,000	$0
16	Aux Power/DCS/CEMS	$2,500	$600
17	Stack	$4,000	$4,000
18	Spare Parts	$1,000	$1,000
19	BOP Engineering	$7,000	$1,000
20	Plant Labor	$1,000	$1,000
21	Subtotal	$127,535	$121,160
22	Escalation	$7,652	$456
23	A&G (Includes Project Engineering)	$4,732	$4,257
24	Total	$139,919	$125,873
25	Contingency	$20,988	$6,294
	Grand Total	$160,906	$132,166

Item 1. This is the BPEI estimate for providing the technology and material associated with a refurbished or new WFGD.

Item 2. This is the estimated cost of installing the BPEI scope of work. The Case 2 Option is based on construction estimates from BPEI. The other estimate is from Zachry.

Item 3. BOP demolition includes removal of existing inlet and outlet ducts, electrical power, insulation and lagging abatement. The new WFGD option also includes removal of the outlet duct support steel. The $3,000 figure is based on LG&E's estimate (from budgetary vendor quotes) to demolish balance of plant work, including the entire existing Unit 3 WFGD, Unit 3 ID fans and ductwork. BPEI included only the demolition work on the old Unit 4 WFGD absorber and recycle tank, the wet/dry duct, and the outlet duct directly above the absorbers.

Item 4. WFGD Foundations assumes the existing foundation can be reused, modified and augmented to accommodate a new WFGD. Add one month to schedule and $2,000,0000 if old foundation must be removed. There are no line items in BPEI's estimate for foundations. The $2,000,000 is based on LG&E's order of magnitude estimate.

Item 5. The refurbished WFGD will require new cable tray, new conduit and rewiring of all existing and new equipment. There will be less equipment in the new WFGD. New equipment, instrumentation, and installation is included in the BPEI or ZHI numbers (see 1&2 above)

Item 6. Based on LG&E's square footage take off of existing wet/dry duct, replacement of the wet/dry duct with 1/4" alloy 686 would require $2.2 million more than BPEI has in their estimate.

Item 7. BPEI planned on using carbon steel for the WFGD outlet duct. Their estimate included only the duct that was required to be removed for the installation of the new module sections. Based on LG&E's material take off, $1.1 million must be added to BPEI's estimate.

Item 8. This replaces the ductwork from the ID Fans to the WFGD that was not included in the BPEI refurbishment scope. This item is included in the new WFGD cases. Estimate based on LG&E material and labor estimate.

Item 9. This replaces the ductwork from the WFGD to the stack that was not included in the BPEI refurbishment scope. This item is included in the new WFGD cases. Based on LG&E material and labor estimate for replacement in kind.

Item 10. This is for replacing or cleaning/painting the structural steel and platforms associated with the existing WFGD and is not included in the BPEI refurbishment scope. Based on LG&E's order of magnitude estimate for BOP labor and material. The recycle pump building is the biggest portion of this work.

Item 11. This is for replacing sections of the existing building and ductwork siding that has deteriorated and is not included in the BPEI refurbishment scope. Based on LG&E's order of magnitude estimate for BOP labor and material. The recycle pump building is the biggest portion of this work. Based on LG&E's order of magnitude estimate.

Item 12. The reaction tank is expected to need repair to the tile lining. Based on LG&E's order of magnitude estimate.

Item 13. This is the BOP piping and mechanical not included in the BPEI scope of work. This is specifically included in the ZHI estimate. Based on LG&E's order of magnitude estimate.

Item 14. This is the heat tracing and insulation associated with the BOP piping and mechanical that was not included in the BPEI scope of work. This is specifically included in the ZHI estimate. Based on LG&E's order of magnitude estimate.

Item 15. In order to utilize new 1&2 and 4 WFGD's to dewater rebuild, assume new pond will be required along with pumps and segregated piping systems. Based on LG&E's order of magnitude estimate.

Item 16.   After start-up, the existing Unit 4 WFGD will be powered from the Unit 3 Generator. If a new WFGD is built, new switchgear and DCS will be provided. This cost is included by ZHI (Item 2). A new CEMS is included in all cases.

Item 17. Because stack velocity will be 75 fps, a special dewatering system will have to be installed. Based on LG&E's order of magnitude estimate.

Item 18. Spare parts are not included in the BPEI or Zachary scope of work and are included here as the same for all cases. Based on LG&E's order of magnitude estimate.

Item 19. BOP Engineering is to cover the Owner's Engineer cost as well as miscellaneous project expenses. Based on LG&E's order of magnitude estimate.

Item 20. Plant Labor is assumed to be the same for all cases. Based on LG&E's order of magnitude estimate.

Item 21. Subtotal of all above costs.

Item 22. Escalation is 6% of the subtotal in the refurbishment and new WFGD cases. Escalation shown for the revised case is for Non-Zachry costs. Escalation is included in the Zachry cost estimate shown in Item 2. Based on LG&E's order of magnitude estimate.

Item 23. A&G are project related expenses.

Item 24. Total of all above costs.

Item 25. Contingency is set at 15% for the refurbishment case due to the higher risk of unknown issues. Contingency for the September 25, 2012 Zachry new WFGD case is set at 5%.