COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
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| ELECTRONIC 2022 INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY | )<br>)<br>)<br>) | CASE NO.<br>2023-00092 |

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on June 12, 2024 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on June 12, 2024 in this proceeding; and

- A written log listing, *inter alia*, the date and time of where each witness's testimony begins and ends on the digital video recording of the evidentiary hearing conducted on June 12, 2024.

A copy of this Notice, the certification of the digital video record, and the hearing log has been served upon all persons listed at the end of this Notice. Parties may view the digital video recording of the hearing at https://youtu.be/t4tytMEmUvQ.

Parties may request a copy of the annotated digital video recording of the hearing by submitting a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done in Frankfort, Kentucky, on October 1, 2024.

Linda C. Bridwell

Linda C. Bridwell, PE
Executive Director

COMMONWEALTH OF KENTUCKY

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In the Matter of:

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| ELECTRONIC 2022 INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY | ) ) ) | CASE NO. 2023-00092 |

## CERTIFICATION

I, Candace H. Sacre, hereby certify that:

1. The attached flash drive contains a digital recording of the Formal Hearing conducted in the above-styled proceeding on June 12, 2024. The Formal Hearing Log, Exhibits, and Exhibit List are included with the recording on June 12, 2024;

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the Formal Hearing of June 12, 2024, and;

4. The Formal Hearing Log attached to this Certificate accurately and correctly states the events that occurred at the Formal Hearing of June 12, 2024, and the time at which each occurred.

Signed this 30TH day of September, 2024.

Candace H. Sacre

Candace H. Sacre
Administrative Specialist Senior

Stephanie Schweighardt

Stephanie Schweighardt
Kentucky State at Large ID# KYNP 64180
Commission Expires: January 14, 2027

Witness: Kamran Ali; Stephen Blankenship; Thomas Haratym; Jeffrey Huber; Glenn Newman; Kelly Pearce; Gregory Soller; Gary Spitznogle; Alex Vaughan; Brian West

Judge: Kent Chandler; Angie Hatton; Mary Pat Regan

Clerk: Candace Sacre

| Date: | Type: | Location: | Department: |
|---|---|---|---|
| 6/12/2024 | Public Hearing\Public Comments | Hearing Room 1 | Hearing Room 1 (HR 1) |

| Event Time | Log Event | |
|---|---|---|
| 9:09:15 AM | Session Started | |
| 9:09:16 AM | DUE TO TECHNICAL ISSUES TRANSCRIPT INCOMPLETE | |
| 9:09:24 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Preliminary remarks. |
| 9:10:01 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Entry of appearance of counsel |
| 9:10:06 AM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Katie Glass, also appearing Kenneth Gish, Hector Garcia Santana. |
| 9:10:24 AM | Asst Atty General West | |
| | Note: Sacre, Candace | Mike West for the AG's Office. |
| 9:10:31 AM | Atty Kurtz KIUC | |
| | Note: Sacre, Candace | Mike Kurtz and Jody Kyler Cohn. |
| 9:10:45 AM | Atty Gary Joint Intervenors | |
| | Note: Sacre, Candace | Byron Gary, appearing Thomas Cmar, Melissa Legee, and Hema Lochan. |
| 9:10:55 AM | Atty Koenig LS Power | |
| | Note: Sacre, Candace | Brittany Koenig. |
| 9:11:05 AM | Asst Gen Counsel Bellamy PSC | |
| | Note: Sacre, Candace | Ben Bellamy and Jurgens van Zyl. |
| 9:11:33 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Public notice. |
| 9:11:55 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Outstanding motions. |
| 9:12:05 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Public comments. |
| 9:13:24 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Procedural discussion. |
| 9:14:11 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Anything else? |
| 9:14:16 AM | Chairman Chandler | |
| | Note: Sacre, Candace | First witness? |
| 9:14:20 AM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Gary Spitznogle. |
| 9:14:34 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Witness is sworn. |
| 9:14:41 AM | Chairman Chandler - witness Spitznogle | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 9:14:54 AM | Atty Gish Kentucky Power - witness Spitznogle | |
| | Note: Sacre, Candace | Direct Examination. State title? |
| 9:15:05 AM | Atty Gish Kentucky Power - witness Spitznogle | |
| | Note: Sacre, Candace | Support preparation of integrated resource planning report? |

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| 9:15:14 AM | Atty Gish Kentucky Power - witness Spitznogle | | |
| | | Note: Sacre, Candace | Provide responses to data requests? |
| 9:15:21 AM | Atty Gish Kentucky Power - witness Spitznogle | | |
| | | Note: Sacre, Candace | Prepare same report or provide same responses? |
| 9:15:37 AM | Chairman Chandler | | |
| | | Note: Sacre, Candace | Questions? |
| 9:16:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Cross Examination. Work for American Electric Power Service Corporation? |
| 9:17:02 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Introduced as vice president for envinonmental services? |
| 9:17:12 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Explain what job entails? |
| 9:17:36 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | In charge of that team? |
| 9:17:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Who report to? |
| 9:17:51 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Employed by AEPSC, subsidiary of AEP Company, Inc.? |
| 9:18:04 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Not employed directly by Kentucky Power? |
| 9:18:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Role to evaluate environmental regulations and applicability? |
| 9:18:23 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Assist in preparation of IRP? |
| 9:18:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Just environmental pieces? |
| 9:18:33 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Reviewed entire IRP? |
| 9:18:43 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Generally familiar with what else in IRP? |
| 9:18:48 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Sponsored responses, assist in preparing responses by anybody else? |
| 9:19:07 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Maybe other specific ones but not all broadly? |
| 9:19:13 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Review comments from intervening parties? |
| 9:19:19 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Participate in preparation of response to comments? |
| 9:19:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Part of responsibilities keeping track of environmental regulations? |
| 9:19:44 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Follow announcements from EPA? |
| 9:19:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Assume familiar announcements Apr 25 of new regulations relating to electric generating units? |
| 9:20:35 AM | Atty Gish Kentucky Power | | |
| | | Note: Sacre, Candace | Object. |
| 9:23:38 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | Cross Examination (cont'd). To be clear, Apr 25 after IRP and responses? |
| 9:23:45 AM | Atty Gary Joint Intervenors - witness Spitznogle | | |
| | | Note: Sacre, Candace | All four still applicable right now? |

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| 9:23:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Greenhouse gas regulations under Section 111 Clean Air Act, reviewed those? |
| 9:24:00 AM | Atty Gary Joint Intervenors | |
| | Note: Sacre, Candace | Table EPA published, show on screen. |
| 9:24:35 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Familiar with this table? |
| 9:24:44 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Reviewed this before? |
| 9:24:47 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Generally, what contains, is table BSER At-A-Glance, state what BSER is? |
| 9:24:56 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | If told you Best System of Emission Reduction, sounds right? |
| 9:24:56 AM | Via Presentation Activated | |
| 9:25:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | At top, two categories, existing steam generators and new and reconstruted stationary combustion turbines? |
| 9:25:16 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Below that contains what standards promulgated are? |
| 9:25:23 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | As far as aware, consistent with what promulgated? |
| 9:25:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Requirements for steam generators, compliant with carbon capture and sequestration? |
| 9:26:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Long-terms units, plan to operate 2039 or beyond? |
| 9:26:15 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Other side, requirements new and reconstructed stationary combustion turbines? |
| 9:26:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | At top, Phase 1 and Phase 2 along timeline? |
| 9:26:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Different subcategories of stationary combustion turbines, low load capacity factor less than 20 percent? |
| 9:26:55 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Intermediate load between 20 and 40 percent? |
| 9:26:59 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | For two subcategories, Phase 1 standards of 160 pounds of CO2 per million BTU and 1170 pounds of CTU per megawatt hour? |
| 9:27:16 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | But no Phase 2 standards for those? |
| 9:27:20 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Baseload subcategory at bottom have capacity factor greater than 40 percent, are requirements? |
| 9:28:01 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Baseload subcategory, initial standard 800 pounds per megawatt hour lower but even lower once 2032 hits? |
| 9:28:12 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In IRP, familiar with preferred plan selected? |
| 9:28:22 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | And, in IRP, new gas combustion turbine on line early 2029 selected? |
| 9:28:23 AM | Via Presentation Deactivated | |

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| 9:28:34 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Recall in response stated Kentucky Power plan for new gas plant operate at long-term capacity factor of 30 percent? |
| 9:29:06 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Not look at long-term capacity factor of plant? |
| 9:29:15 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Sound about right? |
| 9:29:20 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Capacity factors not stay same every year? |
| 9:29:26 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Vary from year to year? |
| 9:29:36 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Have available your responses? |
| 9:30:17 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Specifically, Staff 2-31? |
| 9:30:32 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Not one responded to, take minute to review, information in table, new gas CT chosen by model capacity factor varies from as low as 26 percent up to 58 percent? |
| 9:31:02 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Is that what table states? |
| 9:31:10 AM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Referring to attachment to response? |
| 9:31:26 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Combustion turbine selected modeling picked run between 26 and 58 percent? |
| 9:31:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Accept operating limit or implement CCS 90 percent carbon capture? |
| 9:31:59 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Signed comments on behalf of AEP on rule? |
| 9:32:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Appear be those comments? |
| 9:33:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | And that is your signature? |
| 9:33:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Submitted comments, carbon capture, company stated, reading? |
| 9:33:12 AM | Via Presentation Activated | |
| 9:33:32 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Not believe CCS achieveable on timeline of rule? |
| 9:33:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Logistic challenges? |
| 9:33:55 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | After captured, what do with it also issue? |
| 9:34:22 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Procedural discussion. |
| 9:35:18 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Generally, significant hurdles to achieving carbon capture? |
| 9:35:34 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Another issue, running of carbon capture system takes significant energy to run? |
| 9:35:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Parasitic load what called? |
| 9:35:58 AM | Via Presentation Deactivated | |

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| 9:36:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Also follow developments around National Ambient Air Quality Standards? |
| 9:36:15 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | EPA reviews and updates those periodically every five years, each time go down or stay same? |
| 9:36:26 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | After NAAQS adopted, EPA designate areas attainment or nonattainment? |
| 9:36:35 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | States also submit infrastructure SIP or ISIP? |
| 9:36:43 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Part of that, showing state not contribute nonattainment or interfere with maintenance or significant deterioration downwind? |
| 9:36:53 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | The interstate transport portion of ISIP? |
| 9:36:59 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Familiar with EPA having found Kentucky submittals deficient regard interstate transport? |
| 9:37:09 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Next step, federal implementation plan? |
| 9:37:18 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | How long been in your profession evaluating regulations? |
| 9:37:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Also followed previous developments around this? |
| 9:37:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Familiar with four-step process EPA uses? |
| 9:37:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Used same four-step process each time updated? |
| 9:38:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Cross-state air pollution rule, CSAPR update, revised CSAPR update, and the Good Neighborhood Plan, familiar with all those? |
| 9:38:18 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Current Good Neighbor Plan undergoing litigation, SIP disapproval for Kentucky stayed by Sixth Circuit? |
| 9:38:34 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Rule undergoing separate litigation in DC circuits? |
| 9:38:43 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Rule not stayed by court? |
| 9:38:49 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | EPA separately stayed Good Neighbor Plan? |
| 9:39:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | EPA stay, when EPA stayed the Good Neighbor Plan, reinstated previous allowance system? |
| 9:39:26 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | For Kentucky, new plan under Good Neighbor Plan Group 3, prevoius plan also Group 3? |
| 9:39:37 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Kentucky under old Group 3 allowance system? |
| 9:39:43 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Revised CSAPR updates Group 2 in effect up till 2021? |
| 9:40:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Looking Group 2, familiar with allocations made under that annually? |

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| 9:40:36 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | JI 3, spreadsheet look familiar? |
| 9:41:07 AM | Via Presentation Activated | |
| 9:42:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Titled unit level allocations underlying data for CSAPR, contains allocations for 2017 and 2018 and beyond for Group 2, Big Sandy first facility listed under Kentucky Rows 842 and 843? |
| 9:42:42 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Allocations for BSU 1, Big Sandy, converted gas portion of facility? |
| 9:42:54 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Also allocations for BSU 2, former coal unit since shut down? |
| 9:43:06 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | BSU 1 allocations were 287 tons for ozone season, and BSU 2 were 758 tons for ozone season? |
| 9:43:22 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Once Unit 2 shut down, all go to Big Sandy, 1,000 allowances annually? |
| 9:43:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Group 3 allowances, look familiar? |
| 9:44:10 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | At bottom, Final Merged RCU allocations, revised CSAPR update allocations? |
| 9:44:18 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Scrolling down to Kentucky, Row 304, Big Sandy first unit, slight bump in 2021, back down 2022 and beyond, 373 down to 273 allowances for ozone seasons, allocation currently in effect? |
| 9:44:42 AM | Via Presentation Deactivated | |
| 9:45:05 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Procedural discussion. |
| 9:45:38 AM | Via Presentation Activated | |
| 9:45:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Not have responses in front of you? |
| 9:46:27 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | One of two people responded to Joint Intervenor 1-20? |
| 9:46:28 AM | Via Presentation Deactivated | |
| 9:47:20 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Something you prepared or Haratym? |
| 9:47:35 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Able answer questions? |
| 9:47:41 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Column K, ozone season NOx emissions, allowances Big Sandy used also Mitchell and Rockport? |
| 9:48:12 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | If summed those five months, those be total ozone season allowances used? |
| 9:48:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | For 2017, sum be 180 allowances, 2018 325, but 2019 and 2020 over 500 allowances? |
| 9:48:54 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Also purchase price consistently listed as zero, covered by 278? |
| 9:49:34 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In 2021, total comparable to Group 3, spreadsheet for 2021 and 2022 and beyond? |

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| 9:50:07 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | 2021 Big Sandy used 235 tons and 175 tons, all data reported to EPA on regular basis? |
| 9:50:24 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Some made publicly available through clean air markets program data CAMPD, familiar? |
| 9:50:25 AM | Via Presentation Activated | |
| 9:51:10 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Format look familiar, downloaded data from CAMPD? |
| 9:51:25 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Familiar what included? |
| 9:51:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Scrolling over, facility downloaded Big Sandy, Column F 2017-2023? |
| 9:51:45 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Scrolling over, Column O, NOx mass short tons? |
| 9:52:15 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | NOx mass short tons line up through 2022 with Attachment 1? |
| 9:52:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | 2023 looks like Big Sandy 1 emitted 400 tons of NOx? |
| 9:52:39 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Next column, NOx rates in pounds per million Btu? |
| 9:52:54 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Stays relatively consistent? |
| 9:53:03 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | What changes how much being operated? |
| 9:53:15 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | At lower load, NOx emissions higher or lower? |
| 9:53:25 AM | Via Presentation Deactivated | |
| 9:53:31 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | If operating at lower load, higher emissions? |
| 9:53:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Emissions rate generally higher? |
| 9:53:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Highest heat input in years with highest emissions? |
| 9:54:28 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Still have response to Staff 2-31? |
| 9:54:40 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In table, looks like Big Sandy selected dispatch at 72 percent? |
| 9:54:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In 2024, 79 percent, generally operating at about 50 or 60 percent capacity factor? |
| 9:55:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Returning to Group 2 and Group 3 allowances, Group 2 Big Sandy more allowances each year? |
| 9:55:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Emissions not gone down at all? |
| 9:56:03 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Capacity factor not really changed too much, up slightly next few years? |
| 9:56:46 AM | Via Presentation Activated | |
| 9:56:47 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Go back for a second. |

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| 9:58:17 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Cross Examination (cont'd). Returning to CAMPD, provides emissions information, also allowance information? |
| 9:58:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Available for download, first column, program code, look familiar to you? |
| 9:58:45 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | CSOS G2, Row 6 CSOS G3, make sense to you cross-state ozone season Group 2 and ozone season Group 3? |
| 9:59:05 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Next to that, the year 2017 through 2022, would fit with Group 2 ending in 2020 and Group 3 starting in 2021? |
| 9:59:19 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Make sense be allowances under Group 2 and Group 3? |
| 9:59:27 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | NOx emissions allowances? |
| 9:59:33 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Same as emissions just talking about from Attachment 1 and CAMPD? |
| 9:59:40 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Discussion of exhibits. |
| 10:01:09 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Cross Examination (cont'd). JI 6, scrolling over, Column H, compliance year allowances allocated, see that column? |
| 10:01:32 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Under rows marked Group 2, Rows 2 through 5, allocations 1,045 each year? |
| 10:01:35 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Lines up what allocated under Group 2, JI 3 spreadsheet? |
| 10:01:46 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Group 3, emissions allocations down to 379, annually Big Sandy allocated 279 allowances? |
| 10:02:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Column J, emissions short tons, generally lines up with Attachment 1 JI 1-20 as well as JI 5? |
| 10:02:28 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Equivalent to allowances deducted each year? |
| 10:02:38 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Allowances carried over? |
| 10:02:42 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | What left over, allowances held at trading deadline minus emissions results in allowances left over? |
| 10:02:52 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Carried over to next year? |
| 10:03:10 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Previous spreadsheet, ozone season emissions in 2023 400 tons? |
| 10:03:13 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Last year, Big Sandy also allocated 279 allowances? |
| 10:03:22 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | 279 plus 63 be 430-someting? |
| 10:03:31 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Big Sandy not have enough allowances what allocated or left over? |
| 10:03:38 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Aware allowances be purchased or how been obtained? |

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| 10:03:50 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Overcome some way through purchase or trade? |
| 10:03:58 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Looks like capacity factor at least as much or greater what historically capacity factor? |
| 10:04:13 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Emissions likely at or above 400 tons going forward? |
| 10:04:24 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | If model is correct in selecting Big Sandy, dispatch allowances purchases going forward next several years? |
| 10:04:24 AM | Via Presentation Deactivated | |
| 10:04:37 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Good Neighbor Plan set new requirements reaching compliance downwind 2015 ozone standard? |
| 10:04:42 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Generally allowances over time continue to decrease? |
| 10:04:46 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Familiar with how EPA determines allowances allocated? |
| 10:04:51 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Determined reasonable control level for units be? |
| 10:04:58 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Uncontrolled coal units, determined reductions be added by 2026 or 2027? |
| 10:05:02 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Same for uncontrolled gas units? |
| 10:05:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Not require installation of specific control? |
| 10:05:22 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Determines statewide, these are controls get to emissions level to meet need? |
| 10:05:33 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Then allocates decreasing pool amongst existing units? |
| 10:05:38 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Pool decreasing, allocations to each unit within each state also decrease? |
| 10:05:42 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Still at 6? |
| 10:07:43 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Response JI 1-20, have that in front of you? |
| 10:07:53 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In response, Part A, asked about application of new FIP, Good Neighborhood Plan, both you and Haratym worked on, states, reading? |
| 10:08:10 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Having to purchase allowances based on dispatch now? |
| 10:08:29 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Dispatch of unit projected go up or stay same? |
| 10:08:39 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Allowances continue go down? |
| 10:08:48 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Amount of purchases have to go up? |
| 10:09:29 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Spreadsheet 2 in response to B, Attachment 2, NOx cost for emissions, something you prepared? |

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| 10:09:30 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Looking at that, price of emissions over time goes up, goes down over time? |
| 10:10:08 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Looking at average annual price per short ton in 2023 starts at $71 per short ton? |
| 10:10:31 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Goes down $69, $65 over time, 2029 prices forecast go down? |
| 10:10:49 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Starting at high of $71 but going down? |
| 10:10:58 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Need at Big Sandy go up, allowances go down, price expected go down or up? |
| 10:11:41 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | In response to JI 1-20D company asked whether additional control measures needed, responded Kentucky Power not anticipate additional pollution control measures or equipment? |
| 10:12:07 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Still be the case? |
| 10:12:20 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Install controls or purchase allowances? |
| 10:12:42 AM | Atty Gary Joint Intervenors - witness Spitznogle | |
| | Note: Sacre, Candace | Aware whether evaluation AEP or Kentuck Power done? |
| 10:13:03 AM | Atty Gary Joint Intervenors | |
| | Note: Sacre, Candace | Request post-hearing evaluation of whether need for allowances or need to install control equipment economically more favorable at Big Sandy. |
| 10:13:04 AM | POST-HEARING DATA REQUEST | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | EVALUATION WHETHER NEED FOR ALLOWANCES OR NEED TO INSTALL POLLUTION CONTROL EQUIPMENT AT BIG SANDY MORE ECONOMICALLY FAVORABLE |
| 10:13:39 AM | Atty Gary Joint Intervenors | |
| | Note: Sacre, Candace | Move admit JI-1 through 6, |
| 10:13:58 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Admit JI 1 - 6. |
| 10:14:03 AM | JOINT INTERVENORS HEARING EXHIBIT 1 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | BEST SYSTEM OF EMISSION REDUCTION - BSER AT-A-GLANCE |
| 10:14:09 AM | JOINT INTERVENORS HEARING EXHIBIT 2 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | AEP COMMENTS |
| 10:14:17 AM | JOINT INTERVENORS HEARING EXHIBIT 3 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | GROUP 2 ALLOWANCE ALLOCATIONS |
| 10:14:22 AM | JOINT INTERVENORS HEARING EXHIBIT 4 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | GROUP 3 ALLOWANCE ALLOCATIONS |
| 10:14:28 AM | JOINT INTERVENORS HEARING EXHIBIT 5 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | CSOS GROUP 2 |
| 10:14:29 AM | JOINT INTERVENORS HEARING EXHIBIT 6 | |
| | Note: Sacre, Candace | ATTY GARY JOINT INTERVENORS - WITNESS SPITZNOGLE |
| | Note: Sacre, Candace | CSOS GROUP 3 |

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| 10:14:32 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 10:14:38 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Cross Examination. Role with IRP process, advise on environmental regulations team considers and implements in IRP? |
| 10:14:58 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When start advising on IRP process? |
| 10:15:25 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Sometime in 2022? |
| 10:15:31 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When having discussions, what regulations concerned about? |
| 10:16:11 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When say regulations in place at time, have thought to consider Good Neighbor plan at all? |
| 10:16:15 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Comment period open till Summer 2022, final rule implemented Mar 15 2023? |
| 10:16:21 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When doing IRP, team aware of Good Neighbor plan? |
| 10:16:56 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | How discussion function for long-term planning? |
| 10:17:56 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When rule become actionable, when start taking action? |
| 10:18:19 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Look much farther ahead? |
| 10:19:12 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | How long take to filter information back? |
| 10:19:24 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | When team at Kentucky Power aware of likely impact or likeliness finalized? |
| 10:20:27 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Also help file permits, part of process? |
| 10:20:37 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Walk me through what process looks like proposed CT here, time line for that? |
| 10:20:55 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Walk me through permitting process and what timeline is? |
| 10:22:05 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | For new source, need quite a few permits? |
| 10:22:21 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Each is individual and own process? |
| 10:22:35 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Ever been part of team from start to finish? |
| 10:22:48 AM | Staff Atty van Zyl PSC - witness Spitznogle | |
| | Note: Sacre, Candace | Not able tell me how long process that is? |
| 10:23:03 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 10:23:10 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Redirect? |
| 10:23:12 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Recess until 10:45. |
| 10:23:40 AM | Session Paused | |
| 10:23:54 AM | Session Resumed | |
| 10:24:33 AM | Session Paused | |

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| 10:53:46 AM | Session Resumed | |
| 10:54:02 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on the record. |
| 10:54:06 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Next witness? |
| 10:54:10 AM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Brian West. |
| 10:54:22 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Witness is sworn. |
| 10:54:33 AM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 10:54:52 AM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | Direct Examination. Business position and employer? |
| 10:55:09 AM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | Sponsor responses to data requests and portions of IRP report? |
| 10:55:18 AM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | Corrections? |
| 10:55:23 AM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | Asked same questions, information provided be same? |
| 10:55:35 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Mr. West? |
| 10:55:43 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Cross Examination. Resources in proposed plan, calls for 48 megawatts of CT gas in '29? |
| 10:55:50 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Approaching four and a half years from 2029, timeline company go through and when taking steps towards construction and planning? |
| 10:57:11 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Mentioned six years, saying six-year period until plant coming on line? |
| 10:57:31 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Any steps been taken at this time? |
| 10:57:38 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Assume 2029 projection for bringing resources online outdated? |
| 10:58:09 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Talk about peak demand, exhibit to IRP report, summer peak demand 1,000 MW and winter 1200 to 1300? |
| 10:58:35 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | IRP planned for nine percent reserve margin on summer peak? |
| 10:58:58 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Aware IRP report planning to meet PJM capacity requirements or not aware? |
| 10:59:14 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | PJM capacity requirements relate to summer peak or winter peak or both? |
| 10:59:19 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | If plan meet summer peak, leave uncovered for portion of winter peak? |
| 11:00:08 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Familiar with RFPs issued recently by company? |
| 11:00:20 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Solicited 875 MW resources in summer and 1300 in winter? |

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| 11:00:44 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Solicitations consistent with plan in IRP or trying to do something different meet winter peak? |
| 11:01:33 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Familiar with six or seven portfolios modeled in IRP? |
| 11:01:45 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Aware only one of portfolios included combined cycle? |
| 11:01:53 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | IRP states, reading, language sound consistent with what in IRP? |
| 11:02:52 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Under Figure 74, annual resource editions in CC portfolio? |
| 11:02:59 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Second sentence after that figure? |
| 11:03:05 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Know what optimization entailed? |
| 11:03:18 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Have information combined cycle plants less expensive than CT units? |
| 11:03:32 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Proposed plan called for 700 MW wind all transmitted from outside Kentucky? |
| 11:03:54 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Reference PDF 8.69, preferred plan, 800 MW solar 25 percent of which outside Kentucky, in service territory or just within Kentucky generally? |
| 11:05:12 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Have to do with suitability of terrain for placement of resources? |
| 11:05:28 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | 600 of 800 solar within Kentucky, within service territory, clear up, placed elsewhere in Kentucky? |
| 11:06:09 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Not be more efficient Eastern Kentuckians meet energy needs producing own energy? |
| 11:06:22 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Not be more efficient for Eastern Kentuckians meet own energy needs producing own energy? |
| 11:07:24 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Agree comparison between cost using own resources and other resources only be fully analyzed if accounted for transmission cost? |
| 11:08:02 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Any knowledge about whether transmission costs included in models? |
| 11:09:16 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Read AG comment in this case? |
| 11:09:36 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Familiar with references made to resource adequacy concerns? |
| 11:09:55 AM | Asst Atty General West - witness West | |
| | Note: Sacre, Candace | Given concerns articulated, Kentucky Power give any consideration to whether utility being self sufficieint? |
| 11:10:56 AM | Chairman Chandler | |
| | Note: Sacre, Candace | Mr. Kurtz? |
| 11:11:06 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Cross Examination. Agree since IRP filed in March 2023 a lot of significant developments in industry? |

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| 11:11:19 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | IRP not model capacity factor limitations in final CO2 rule? |
| 11:11:32 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | IRP assumed $10 and $43 per megawatt hour CO2 tax or penalty or cost? |
| 11:11:47 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Aware no CO2 cost modeled in every scenario? |
| 11:12:15 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Know now EPA not  propose CO2 cost, proposed capacity factor limitations new gas generation? |
| 11:12:33 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | ELCC familiar with that? |
| 11:12:44 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Capacity value PJM puts on resources? |
| 11:12:54 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | ELCC for solar gone way down? |
| 11:12:59 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Have to have more megawatts of solar to get same capacity value? |
| 11:13:13 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | IRP assumes cost of $2100 a  kW for wind? |
| 11:13:29 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Capital cost be approximately $1.47 billion? |
| 11:13:45 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Somebody would build it would cost $1.4 billion? |
| 11:14:05 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Know effective property tax rate Kentucky Power used in last rate case? |
| 11:14:20 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Assume 0.66 percent, if spent ??? |
| 11:14:43 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Local govenment zero tax money if out of state? |
| 11:14:59 AM | Session Note Entry | |
| | Note: Sacre, Candace | Would be zero if built out of state? |
| 11:15:06 AM | Session Note Entry | |
| | Note: Sacre, Candace | Not be local construction jobs? |
| 11:15:17 AM | Session Note Entry | |
| | Note: Sacre, Candace | No permanent jobs if built out of state? |
| 11:15:31 AM | Session Note Entry | |
| | Note: Sacre, Candace | Generic modeling, not location specific? |
| 11:15:46 AM | Session Note Entry | |
| | Note: Sacre, Candace | Existing site in Lawrence County, transmission already at site? |
| 11:16:10 AM | Session Note Entry | |
| | Note: Sacre, Candace | But transmission there? |
| 11:16:21 AM | Session Note Entry | |
| | Note: Sacre, Candace | Gas peipleine capacity going to site? |
| 11:16:28 AM | Session Note Entry | |
| | Note: Sacre, Candace | One or two gas lines? |
| 11:16:34 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Know who supplier is? |
| 11:17:43 AM | Session Note Entry | |
| | Note: Sacre, Candace | This is part of rate aspect of plan, discusses preferred plan, go to every end where rank plans, reading correct CC portfolios combined cycle? |

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| 11:18:40 AM | Session Note Entry | |
| | Note: Sacre, Candace | Combined cycle slightly less expensive than ??? |
| 11:19:08 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Less risky, cost risk ??? |
| 11:19:26 AM | Session Note Entry | |
| | Note: Sacre, Candace | Local impacts, CAPEX ??? |
| 11:20:47 AM | Session Note Entry | |
| | Note: Sacre, Candace | Rate impacts of proposed plan? |
| 11:20:59 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | KIUC Exhibit, how should read this, what does that represent? |
| 11:22:09 AM | Session Note Entry | |
| | Note: Sacre, Candace | Know if residential or average across all customers? |
| 11:22:22 AM | Session Note Entry | |
| | Note: Sacre, Candace | Footnote says ??? |
| 11:22:31 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Know how Mitchell modeld in this? |
| 11:22:43 AM | Session Note Entry | |
| | Note: Sacre, Candace | Is it 12-31-29 or June 2 2028, PJM planning year???? |
| 11:24:24 AM | Session Note Entry | |
| | Note: Sacre, Candace | This says ??? |
| 11:24:39 AM | Session Note Entry | |
| | Note: Sacre, Candace | Page 3 of exhibit, dollar amount of capacity purchases, in 2028 is ???, just for Jun 1 2028 to ??? |
| 11:25:13 AM | Session Note Entry | |
| | Note: Sacre, Candace | Know if modeling assumed all ??? |
| 11:25:22 AM | Session Note Entry | |
| | Note: Sacre, Candace | Reasonable charge customers for capacity purchased and ??? |
| 11:25:56 AM | Atty Kurtz KIUC - witness West | |
| | Note: Sacre, Candace | Kentucky Power retain ownership unless or until sold or transferred? |
| 11:26:15 AM | Session Note Entry | |
| | Note: Sacre, Candace | Data response Staff asked you, remaining net book cost |
| 11:26:36 AM | Session Note Entry | |
| | Note: Sacre, Candace | Objection. |
| 11:26:43 AM | Session Note Entry | |
| | Note: Sacre, Candace | How netbook cost modeled ??? |
| 11:26:54 AM | Session Note Entry | |
| | Note: Sacre, Candace | Know if rate impact KIUC Exhibit 2 assumes consumers continue paying for fixed cost of Mitchell when not getting ??? |
| 11:27:25 AM | Session Note Entry | |
| | Note: Sacre, Candace | If Kentucky Power continues to own it, seek recover net book ??? |
| 11:27:51 AM | Session Note Entry | |
| | Note: Sacre, Candace | Move to introdce |
| 11:28:17 AM | Session Note Entry | |
| | Note: Sacre, Candace | Objection |
| 11:28:23 AM | Session Note Entry | |
| 11:28:30 AM | Session Note Entry | |
| 11:31:14 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Cross Examination. |
| 11:31:24 AM | Session Note Entry | |
| 11:31:30 AM | Session Note Entry | |
| | Note: Sacre, Candace | Recall if said additional resource selection ??? |
| 11:31:47 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Ablel to say whether that stage in process has occurred? |

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| 11:32:13 AM | Session Note Entry | |
| | Note: Sacre, Candace | Would be responses to ???? |
| 11:32:21 AM | Session Note Entry | |
| | Note: Sacre, Candace | Agreements executed but June? |
| 11:32:32 AM | Session Note Entry | |
| | Note: Sacre, Candace | Able to say that part of process has occurred? |
| 11:32:42 AM | Session Note Entry | |
| | Note: Sacre, Candace | Kentucky Power made decisions ??? |
| 11:34:01 AM | Session Note Entry | |
| | Note: Sacre, Candace | Objection. |
| 11:34:11 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Regulatory processes planned at this time ??? |
| 11:34:32 AM | Session Note Entry | |
| | Note: Sacre, Candace | Have data responses? |
| 11:34:48 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Turn to Response 2-13, relates to whether specific plans ??? |
| 11:35:32 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Able to say that still true today? |
| 11:36:01 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Is data response still accurate today? |
| 11:36:18 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Still accurate today? |
| 11:36:35 AM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Privilege. (Click on link for further comments.) |
| 11:39:21 AM | Session Note Entry | |
| | Note: Sacre, Candace | Confidential. |
| 11:39:45 AM | Private Mode Activated | |
| 11:39:46 AM | Private Recording Activated | |
| 11:50:44 AM | Normal Mode Activated | |
| 11:50:45 AM | Public Recording Activated | |
| 11:50:55 AM | Session Note Entry | |
| | Note: Sacre, Candace | Mr. Cmar? |
| 11:51:00 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Cross Examination (cont'd). Refer you to Kentucky Power Response JI 2-34, shows Kentucky Power capacity purchases through ??? |
| 11:51:53 AM | Session Note Entry | |
| | Note: Sacre, Candace | Response dated July 24, believe responses provided Sept 28 ??? |
| 11:52:14 AM | Session Note Entry | |
| | Note: Sacre, Candace | Since Sept 2023 Kentucky Power entered into any other contracts ??? |
| 11:52:30 AM | Session Note Entry | |
| | Note: Sacre, Candace | Company anticipate needing to make capacity purchases for ??? |
| 11:52:48 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Know when PJM delivery year when company need to be going through process? |
| 11:53:51 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Not something on radar currently? |
| 11:54:09 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Refer to KIUC 1, page 174, two figures 80 and 81, show Kentucky Power capacity under preferred plan? |
| 11:55:06 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | For 2026, show Kentucky Power adding 100 MW of new wind resources? |

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|---|---|---|
| 11:55:22 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Know if company current plan, add 100 MW new wind in 2026? |
| 11:56:41 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Fair to say 100 MW capacity need filled based on resonses to 2023 RFP? |
| 11:57:05 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Back to Figure 80, shows 2027 250 MW solar addition and 100/100 for wind? |
| 11:57:36 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Clarify what 100/100 means? |
| 11:58:00 AM | Session Note Entry | |
| | Note: Sacre, Candace | 200 total, 100 from each tranche? |
| 11:58:12 AM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Would answers be same for 2026? |
| 11:58:34 AM | Session Note Entry | |
| | Note: Sacre, Candace | Inflation Reduction Act, familiar with ??? |
| 11:59:06 AM | Session Note Entry | |
| | Note: Sacre, Candace | Aware that tax credit bonus for both ??? tax credit and investment tax credit? |
| 11:59:25 AM | Session Note Entry | |
| | Note: Sacre, Candace | Someone speak to what analysis company has done to evaluate these ??? |
| 11:59:53 AM | Session Note Entry | |
| | Note: Sacre, Candace | Aware of whether US Dept of Energy developed a map of which communities ??? |
| 12:00:16 PM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Know if anyone at Kentucky Power looked into this issue? |
| 12:00:35 PM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Not  have sense of what percentage of Kentucky Power territory be considered an energy community? |
| 12:01:01 PM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Know anticipated timing of Kentucky Power next IRP? |
| 12:01:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Has Kentucky Power done any ??? |
| 12:02:26 PM | Atty Cmar Joint Intervenors - witness West | |
| | Note: Sacre, Candace | Nine to ten months? |
| 12:02:46 PM | Session Note Entry | |
| | Note: Sacre, Candace | Ms. Koenig? |
| 12:02:55 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Recess for lunch until 12:55. |
| 12:03:14 PM | Session Paused | |
| 1:00:42 PM | Session Resumed | |
| 1:00:58 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on the record. |
| 1:01:13 PM | Session Note Entry | |
| | Note: Sacre, Candace | Review KIUC Exhibit 3, page 7 is attachment, last two pages from record.  No objection. |
| 1:01:39 PM | Session Note Entry | |
| 1:01:45 PM | Session Note Entry | |
| 1:01:49 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Cross Examination.  When discussion with West, Kentucky Power ??? |
| 1:02:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Recedive all benefits through end of calendar year? |

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| 1:02:42 PM | Session Note Entry | |
| | Note: Sacre, Candace | Based on stated in IRP, proposed plan to build ??? |
| 1:02:55 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Tell me by the end of the year proposes have that built? |
| 1:03:37 PM | Session Note Entry | |
| | Note: Sacre, Candace | There might be, assumption is 1-1 of 2029? |
| 1:03:54 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Fair to say not expect gap between receiving energy from Mitchell and ??? |
| 1:04:25 PM | Session Note Entry | |
| | Note: Sacre, Candace | Difficult to provide time line? |
| 1:04:40 PM | Session Note Entry | |
| | Note: Sacre, Candace | As far as lease ???? |
| 1:05:01 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Still operating on position six years is about right? |
| 1:05:28 PM | Session Note Entry | |
| | Note: Sacre, Candace | Follow up to that, in event significant ???, company prepare contingency plans what to do for providing capacity or energy between 1-1-29 and 2030? |
| 1:06:58 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | As far as bilateral contracts, when have to prepare to look for available capacity? |
| 1:07:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | Relatively short period of time? |
| 1:07:54 PM | Session Note Entry | |
| | Note: Sacre, Candace | Anyone discuss principles of environmental, NGCG? |
| 1:08:14 PM | Session Note Entry | |
| | Note: Sacre, Candace | Somebody more ???? |
| 1:08:26 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | You do not have experience? |
| 1:08:35 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Issue RFPs already, tell us what happens when RFP comes through your door when you receive it? |
| 1:09:15 PM | Att Glass Kentucky Power | |
| | Note: Sacre, Candace | Just need to know ??? |
| 1:09:28 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Understanding of how Kentucky Power and AEP process these? |
| 1:10:32 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Who directs review process, you or AEP? |
| 1:11:28 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | In making final decision, just a business decision? |
| 1:13:49 PM | Session Paused | |
| 1:18:02 PM | Session Resumed | |
| 1:18:15 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Ask your question again? |
| 1:18:35 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Cross Examination. Ready for recommendation, time line what time takes to get to that recommendation? |
| 1:19:45 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | How long usually before decision made, full process? |
| 1:20:46 PM | Staff Atty van Zyl PSC - witness West | |
| | Note: Sacre, Candace | Big Sandy, know not modeling individual, original plan Big Sandy retire in 2031? |

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| 1:22:09 PM | Staff Atty van Zyl PSC - witness West | | |
| | | Note: Sacre, Candace | Based on that, have information as to whether model allowed retire it before 2026 period or economic deision model spits out? |
| 1:22:54 PM | Staff Atty van Zyl PSC - witness West | | |
| | | Note: Sacre, Candace | Based on environmental regulations and all that? |
| 1:23:22 PM | Staff Atty van Zyl PSC - witness West | | |
| | | Note: Sacre, Candace | Regarding solar and wind that Kentucky Power is proposing, is company considered self-owned or what is company evaluating? |
| 1:24:01 PM | Staff Atty van Zyl PSC - witness West | | |
| | | Note: Sacre, Candace | Is any consideration for self-owned or for building that capacity? |
| 1:24:53 PM | Staff Atty van Zyl PSC - witness West | | |
| | | Note: Sacre, Candace | Reason ask also includes 50 MW battery, paired witih solar or wind or just add-on? |
| 1:25:23 PM | Chairman Chandler | | |
| | | Note: Sacre, Candace | Vice Chair? |
| 1:25:29 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Examination. IRP filed a little over a year ago, things have changed, three-year action plan as far as you know still being followed, still general plan, page 183? |
| 1:26:30 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | When KIUC and AG were asking about whether Kentucky Power has plans to build ??? |
| 1:27:26 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Create some jobs? |
| 1:27:38 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Initiate all-source RFP, any plans seek ??? |
| 1:28:23 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Since over a year, how far along in process? |
| 1:28:59 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Same thing with ??? extend life of Big Sandy, that is ongoing? |
| 1:29:25 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Notice in public comments asking for expanded opportunities rooftop solar, something company is looking into? |
| 1:29:59 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | DERs? |
| 1:30:11 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Looks like customers are asking for it, give that some weight? |
| 1:30:29 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | One of customers submitted public comment company free to continuing net metering once cap is met, something company considered? |
| 1:31:08 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | Not required to after that? |
| 1:31:31 PM | Vice Chairman Hatton - witness West | | |
| | | Note: Sacre, Candace | General commentsw where customers as doing company finance solar programs where company pay for solar and take ??? |
| 1:32:10 PM | Session Note Entry | | |
| | | Note: Sacre, Candace | Examination. When look at RFPs and responses, |
| 1:32:49 PM | Session Note Entry | | |
| | | Note: Sacre, Candace | May be confidential. (Click on link for further comments.) |
| 1:33:07 PM | Private Mode Activated | | |
| 1:33:07 PM | Private Recording Activated | | |
| 1:34:14 PM | Normal Mode Activated | | |
| 1:34:14 PM | Public Recording Activated | | |

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| 1:34:22 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on public session. |
| 1:34:35 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Examination. Provide input to company's responses to intervenor comments? |
| 1:35:01 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | One of statements says, reading (click on link for further comments), sound about right? |
| 1:35:43 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Also states, reading (click on link for further comments), goes on to say, reading (click on link for further comments), those comments sound familiar? |
| 1:36:24 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Aware of IRP regulations? |
| 1:36:31 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Involved in ensuring plan meets requirements? |
| 1:36:49 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | IRP regulation, Resource Assessment Acquisition Plan, including ???, separately requirement engage with other utilities, aware of that requirement? |
| 1:38:00 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | What actions did Kentucky Power take to engage with other utilities in state? |
| 1:39:30 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Your position that provision has outlived its usefulness? |
| 1:40:24 PM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Address legal aspects of question. (Click on link for further comments.) |
| 1:41:18 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Examination. Has there been ??? |
| 1:41:34 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Aware of provision in regulation that discusses and describes all options for expansion of generation facilities? |
| 1:42:17 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Table of contents that seem to indicate ??? |
| 1:42:34 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Have IRP in front of you? |
| 1:42:39 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Mind to go to that section? |
| 1:43:12 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Natural gas combined cycle, ??? |
| 1:43:51 PM | Session Note Entry | |
| | Note: Sacre, Candace | In the responses to intervenors comments, RFP is public, if other utilities want to respond, can respond? |
| 1:44:33 PM | Session Note Entry | |
| | Note: Sacre, Candace | In conducting IRP, RFP initiated after ??? |
| 1:44:56 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Issued at very end of discovery of this case? |
| 1:45:08 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | If some other utility want to respond, agree timing of that evidence of argument that Kentucky Power engaged other utilities just by virtual of fact came after? |
| 1:45:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Aware other section that would purport to indicate compliance with ??? |

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| 1:46:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | Participate formally or informally all cases Kentucky Power has before Commission? |
| 1:46:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | Given timing relative to rate case and this case, know whether Kentucky Power asked to ??? |
| 1:46:47 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Wholly unrelated case Kurtz asking about earlier? |
| 1:47:01 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | You all provided those? |
| 1:47:12 PM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | On a confidential basis. |
| 1:47:25 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | ???, five lines down, sentence starts with apart, reading (click on link for further comments), see that? |
| 1:48:16 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Skip past owned, understand what owned refers to there, ??? |
| 1:48:40 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Contracted resources, filed at Commission Nov 3 2023, when says contracted, not include ??? power agreement with Rockport? |
| 1:49:25 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | In ???? contracted for resources? |
| 1:49:42 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | What resources? |
| 1:50:19 PM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Just for the record, |
| 1:50:33 PM | Session Note Entry | |
| | Note: Sacre, Candace | How much power ??? |
| 1:50:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Difference from ??? |
| 1:50:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Only buying ??? |
| 1:50:50 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Buying energy through day ahead in PJM market???? |
| 1:51:21 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | How power plants bought capacity from serving customer needs? |
| 1:52:28 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Buying capacity but not have energy from those units? |
| 1:53:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | When says "contract ??? |
| 1:53:29 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Post-hearing data request specific to response contracted-based membership, what contracts referring to? |
| 1:53:30 PM | POST-HEARING DATA REQUEST | |
| | Note: Sacre, Candace | CHAIRMAN CHANDLER - WITNESS WEST |
| 1:54:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | Part of revenue requirement, sought recovery for executive compensation? |
| 1:54:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | For both Kentucky Power level and ??? |
| 1:54:51 PM | Session Note Entry | |
| | Note: Sacre, Candace | Aware that AEP executive compensation policy relative to ???? |

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| 1:55:11 PM | Session Note Entry | |
| | Note: Sacre, Candace | Ten percent of executive compensation based off megawatts of carbon-free generation? |
| 1:55:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | Aware that is a factor in compensation? |
| 1:55:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | Degree to which executive compensation ???? |
| 1:56:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | Three weights, you in current position on finance side conversations about Kentucky Power contribution to ??? |
| 1:57:13 PM | Session Note Entry | |
| | Note: Sacre, Candace | That part you have had conversations and ???? |
| 1:57:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | Total shareholder return, consideration for executive compensatioin ??? |
| 1:57:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | Insofar as three things taken into account, only EPS ??? |
| 1:58:21 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | If concern is can't use Mitchell as capacity for 2028-2029 delivery year, out of Mitchell Dec 31 2028, if your position not use for your benefit as capacity resource, mean that no one gets benefit of capacity? |
| 1:59:52 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Trying to find out, does anybody get capacity of Mitchell ??? |
| 2:00:16 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Someone else going to have it only last five months, mean that in AEP zone capacity resource that exists in which no one gets use for tha delivery year? |
| 2:01:14 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | About inclusion of that in FRR plan? |
| 2:01:25 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Find that to be distinguishable from responses previously given, |
| 2:02:38 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Reading, (click on link for further comments), sentence means that ??? |
| 2:03:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Were trying to respond consistent with Haratym? |
| 2:03:39 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Thinks Kentucky Power not get ??? |
| 2:04:20 PM | Session Note Entry | |
| | Note: Sacre, Candace | Reading, (click on link for further comments), on next page Item 51 Attachment 1 capacity purchases? |
| 2:05:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | If company position modeling it for being wholly unavailable, mean not being used and should be available to someone else, believe should be taken into account offsetting capacity purchase are modeling? |
| 2:05:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | If someobyd etting first seven months, not be able get it free? |
| 2:05:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | Should be able to buy for last five months ??? |
| 2:06:16 PM | Session Note Entry | |
| | Note: Sacre, Candace | Mitchell not going to disappear, more reasonable ways to consider in modeling? |

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| 2:06:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Know whether Haratym not work for Kentucky Power, not employee? |
| 2:06:51 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not employee of AEP? |
| 2:06:56 PM | Session Note Entry | |
| | Note: Sacre, Candace | Someone hired from Charles River and Associates? |
| 2:07:02 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Give him direction what to do with Mitchell in 2029 delivery year? |
| 2:07:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Assume ten percent of AEP executive compensation tied to increasing megawatts of zero ???, taken into consideration when developing scoring in RFP? |
| 2:08:29 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Did you directly create the rubric? |
| 2:08:45 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Who create scoring rubric? |
| 2:09:02 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Vaughan involved in that? |
| 2:09:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Three separate requests for referrals, thermal wind and solar and battery? |
| 2:09:33 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | ??? |
| 2:09:39 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | All three require projects must be ??? |
| 2:09:56 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Must be indicsated to PJM will be interconnected to PJM or have to be in order be accepted as conforming response? |
| 2:10:35 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Not clear whether must be interconnected ??? |
| 2:11:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Also have to have SIS that has to be ??? |
| 2:11:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Couldl still be possible resource but not necessarily ??? |
| 2:11:37 PM | Chairman Chandler - witness West | |
| | Note: Sacre, Candace | Of all three, identical language in this regard, included in RFP ??? |
| 2:12:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | Ms. Glass? |
| 2:12:18 PM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | Redirect Examination. West questioning, recall? |
| 2:12:35 PM | Session Note Entry | |
| | Note: Sacre, Candace | Agree Soller be best witness how took regulation into account??? |
| 2:12:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Planning manager at ??? |
| 2:12:59 PM | Atty Glass Kentucky Power - witness West | |
| | Note: Sacre, Candace | As far as discussion how Mitchell reflected in FRR plan, Vaughan or Pearce better witness? |
| 2:13:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | More knoweldge than you? |
| 2:13:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kurtz cross examining, you had stated not have interconnection there, clarify what mean by that? |

| | | |
|---|---|---|
| 2:14:20 PM | Session Note Entry | |
| | Note: Sacre, Candace | That would be a multi-year process? |
| 2:14:34 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Anything else for witness? |
| 2:15:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next witness? |
| 2:15:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Glenn Newman. |
| 2:15:36 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 2:15:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Exaination. |
| 2:15:49 PM | Session Note Entry | |
| | Note: Sacre, Candace | Direct Exainatioin. Job title? |
| 2:15:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? |
| 2:16:25 PM | Session Note Entry | |
| 2:16:31 PM | Session Note Entry | |
| 2:16:38 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 2:16:46 PM | Atty Lochan Joint Intervenors - witness Newman | |
| | Note: Sacre, Candace | Cross Examination. In discovery, responses have Glenn Newman, is that you? |
| 2:17:15 PM | Session Note Entry | |
| | Note: Sacre, Candace | What was role in IRP? |
| 2:17:48 PM | Session Note Entry | |
| | Note: Sacre, Candace | When devleop ???? |
| 2:17:54 PM | Session Note Entry | |
| | Note: Sacre, Candace | Invovled throughout process? |
| 2:18:02 PM | Session Note Entry | |
| | Note: Sacre, Candace | Company not include analysis of ???? |
| 2:18:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | Same goes for DER? |
| 2:18:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not include analysis in ??? |
| 2:18:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | But IRA not ??? |
| 2:19:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | Able listen in on conversation with West? |
| 2:19:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next IRP in 2026? |
| 2:19:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | Know if company has plans to consider ??? |
| 2:19:46 PM | Atty Lochan Joint Intervenors - witness Newman | |
| | Note: Sacre, Candace | Company not adjust load forecast for DSM programs? |
| 2:20:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Aware company has ??? |
| 2:20:39 PM | Atty Lochan Joint Intervenors - witness Newman | |
| | Note: Sacre, Candace | Company including these programs in next IRP program? |
| 2:21:12 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 2:21:22 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Cross Examination. Have IRP, pages 23 through 45, various load forecast scenarios, |

| | | |
|---|---|---|
| 2:22:09 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Familiar with that? |
| 2:22:14 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Seven forecasts, energy ???, weather extreme forecast? |
| 2:22:37 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Page 45, reading (click on link for further comments), familiar with how load forecast taken forward into capacity expansion model and AURORA model? |
| 2:23:18 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Had three, be within this range, other four all between high and low? |
| 2:24:06 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Five scenarios modeled, say which load forecast ??? |
| 2:24:24 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Who be property witness answer that? |
| 2:24:35 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Page 36 talk about manufacturing energy sales, and second last sentence says, reading, (click on link for further comments), and again on page 43 large customer changes, describe process where getting information large customers and how ??? |
| 2:27:17 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Said get together and agree, talk about what already included, how make determination whether large customer captured in more general economic forecasting? |
| 2:29:01 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Customer service engineers prepare reports, how far go out? |
| 2:29:21 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Might be approached by large customers approach engineers, two or three years out or less, get idea when might come and what load might be, risk analysis, weighing probability not come and downgrading load? |
| 2:31:14 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Understand why be hesitant include new large loads, some other cases doing forecasts doing planning 10 15 20 years, any mechanism seen other utilities use to capture potential for new large customer five or ???? |
| 2:33:28 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Never predict in eight years some customer shows up, hard to predict that? |
| 2:33:53 PM | Asst Gen Counsel Bellamy PSC - witness Newman | |
| | Note: Sacre, Candace | Looking at ones more a sure thing and projecting into future? |
| 2:34:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Questions? |
| 2:34:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Redirect? |
| 2:34:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next witness? |
| 2:34:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Jeffrey Huber. |
| 2:35:00 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Witness is sworn. |
| 2:35:15 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 2:35:24 PM | Session Note Entry | |
| | Note: Sacre, Candace | Direct Examination. Employer and position? |

| | | |
|---|---|---|
| 2:35:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | Sponsor responses and portions of IRP? |
| 2:35:48 PM | Session Note Entry | |
| | Note: Sacre, Candace | Corrections? |
| 2:35:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | Asked same questions, ??? be same? |
| 2:36:09 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 2:36:17 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Cross Examination. Role in preparation of IRP? |
| 2:37:13 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | ???? |
| 2:37:21 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Purpose of energy efficiency programs ??? |
| 2:37:36 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Used those to identify bundles of energy efficience resources? |
| 2:38:13 PM | Session Note Entry | |
| | Note: Sacre, Candace | Benchmark analysis not use ??? |
| 2:38:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Reason for that were not asked for it? |
| 2:38:35 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Benchmark analysis not speak to ??? |
| 2:38:55 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Bundles contain different service lines? |
| 2:39:15 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Look at cost over service of these energy efficiency measures? |
| 2:40:06 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Explain what meant by full lifetime impact? |
| 2:40:39 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | All of those lifetime impacts were ??? |
| 2:40:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | Counsel? |
| 2:41:02 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Cross Examination. On page 83 of IRP benchmarking, studies germane to Kentucky Power individually or based on other ??? |
| 2:41:47 PM | Atty Lochan Joint Intervenors - witness Huber | |
| | Note: Sacre, Candace | Be more specific? |
| 2:41:58 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Redirect? |
| 2:42:49 PM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Gregory Soller. |
| 2:43:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 2:43:15 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 2:43:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | Title and employer? |
| 2:44:02 PM | Session Note Entry | |
| | Note: Sacre, Candace | Provide services to Kentucky Power to prepare this IRP? |
| 2:44:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | Also provide responses? |
| 2:44:27 PM | Session Note Entry | |
| | Note: Sacre, Candace | Corrections? |

| | | |
|---|---|---|
| 2:44:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | If asked same questions, would answers be same? |
| 2:45:13 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Cross Examination. ???? |
| 2:45:25 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Very small number? |
| 2:45:52 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 2:45:58 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 2:46:02 PM | Session Note Entry | |
| | Note: Sacre, Candace | KIUC Exhibit 2, rate impacts of plan, assist in preparation of Table 23? |
| 2:46:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | At end of 2028, energy from Mitchell ends? |
| 2:46:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Beginning 1-1-29, what do with respect to Mitchell depreciation expense currently in base rates, included? |
| 2:47:18 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Assumes Kentucky Power continue to collect ??? on Mitchell even when plant no longer providing service to Kentucky? |
| 2:47:45 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | What about fixed O&M including labor? |
| 2:48:36 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Recall property taxes excluded? |
| 2:48:45 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | KIUC Exhibit 3, page 3, see 2028 capacity purchase, over what period of time does that cover? |
| 2:49:31 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | In June 2028 to Dec 1 2028 not remove any fixed costs from prior exhibit? |
| 2:49:51 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | To extent company sought to recover at same time still recovering costs in base rates, double recovery? |
| 2:50:21 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | Not related to IRP. (Clink on link for further comments.) |
| 2:50:45 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | For modeling purposes include portion of 2028 capacity and Mitchell fixed costs in base rates? |
| 2:51:46 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Familar with term ELCC? |
| 2:52:30 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Include modeling for that? |
| 2:52:36 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Footnote reflects, reading (click on link for further comments), what is ELCC? |
| 2:53:46 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Generation resource more reliable higher ELCC than solar? |
| 2:54:10 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Turn to page 2 of this, PJM document from which made chart, page 3 most recent, familiar with new ELCC? |
| 2:54:33 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Fixed tilt solar went from ???? |

| | | |
|---|---|---|
| 2:54:48 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | 72 percent reduction? |
| 2:54:56 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | PJM saying now bid into capacity markets ??? |
| 2:55:23 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Solar tracking went from ???? |
| 2:55:36 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Signaling solar not provide much capacity value? |
| 2:56:03 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | May not even want to bid into capacity market getting so little capacity? |
| 2:56:21 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Bottom of page 3, gas combined cycle, 79 percent? |
| 2:56:31 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Considers gas fairly reliable? |
| 2:56:37 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Below that is ??? |
| 2:56:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Recess until 3:15. |
| 2:57:16 PM | Session Paused | |
| 3:24:58 PM | Session Resumed | |
| 3:25:04 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on record. |
| 3:25:21 PM | Chairman Chandler | |
| | Note: Sacre, Candace | KIUC 5 be entered. |
| 3:25:22 PM | KIUC HEARING EXHIBIT 5 | |
| | Note: Sacre, Candace | ATTY KURTZ KIUC - WITNESS SOLLER |
| 3:25:33 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Continue. |
| 3:25:40 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Cross Examination. Preferred plan has 500 MW wind, KIUC 1, page 2, 500 MW wind coming on line prior to 480 MW CT? |
| 3:27:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | Also have solar coming on line 700 MW before gas CT? |
| 3:27:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | Page 95 of IRP, explain that capital cost of wind in 2026, page 95 of IRP, just over $2,000 kW? |
| 3:27:58 PM | Session Note Entry | |
| | Note: Sacre, Candace | Capital cost of utility scale solar, page 96, just under $2,000 kW? |
| 3:28:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | No fuel cost? |
| 3:28:24 PM | Session Note Entry | |
| | Note: Sacre, Candace | Get ??? |
| 3:28:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | On page 87, combined cycle technology, capital cost of just over $1700 per kW in 2029? |
| 3:28:58 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Low heat rate? |
| 3:29:32 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 3:29:40 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 3:29:45 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Include combined cycle in analysis? |

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| 3:29:54 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | KIUC 5 ??? |
| 3:32:13 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | When forced in in 2029, surprise to you high capital cost low energy cost combined cycle did not perform well? |
| 3:32:46 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | When forced in ??? |
| 3:33:24 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Started with combined cycle, then let model select rest of it? |
| 3:33:48 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | When did that in scoring, combined cycle resource portfolio slightly less expensive than preferred plan, even though not select it was cheaper? |
| 3:36:03 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 3:36:07 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 3:36:42 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | According to preferred plan ???? |
| 3:37:11 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Combined cycle, correct? |
| 3:37:23 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Preferrred plan has 700 MW wind and ??? solar? |
| 3:37:37 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Same amount of wind and solar, just pushes out wind and solar further into future? |
| 3:38:50 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Combined cycle portfolio small amount less expensive than preferred plan with CT? |
| 3:39:10 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | None of this have bearing because ??? |
| 3:39:59 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Always changes from ???, if Commission were to tell AEP when come back for CPCN, please not come back without no out-of-state wind, model that? |
| 3:40:44 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | When come back for a CPCN do something, could model scenario with constraint no out-of-state wind? |
| 3:41:18 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | That I don't understand, capital costs worth it because lower cost energy, what I don't get when load up on renewables but then balance out with peaking gas? |
| 3:43:09 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | What is reliability situation, what PJM predicting for that system? |
| 3:43:31 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | What is that report 3R Report, PJM predicting reliability problems? |
| 3:44:14 PM | Atty Kurtz KIUC - witness Soller | |
| | Note: Sacre, Candace | Think PJM welcome Kentucky Power build combined cycle rather than renewables? |
| 3:44:59 PM | Chairman Chandler | |
| | Note: Sacre, Candace | As relates KIUC Hearing Exhibiat 4 and 5, so entered. |
| 3:45:18 PM | KIUC HEARING EXHIBIT 4 | |
| | Note: Sacre, Candace | ATTY KURTZ KIUC - WITNESS SOLLER |
| 3:45:23 PM | KIUC HEARING EXHIBIT 5 | |
| | Note: Sacre, Candace | ATTY KURTZ KIUC - WITNESS SOLLER |

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| 3:45:28 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 3:45:35 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cross Examination.  Page 3 looking at ??? |
| 3:46:13 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Bottom of list, those have 79 percent ELCC and 62 percent ELCC, turn to page 2 those resources not listed on the ELCC chart, the gas combustion turbine and gas CT, is that because ??? |
| 3:47:16 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | PJM would have factored in certain assumptions about ??? in UCAP, trying to find it and could not track it down, know what capacity factors would have been ????? |
| 3:48:27 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Those assumptions also moved downward? |
| 3:48:44 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Heard from West and you shared role in IRP, West said you had heavy direct involvement? |
| 3:49:14 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | As between you and Haratym, what were your specific roles? |
| 3:50:31 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | As far as inputs into AURORA modeling, decision between you and your team ??? |
| 3:51:39 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Supply side resource conditions your team would have come up with list, got approval from Kentucky Power, and sent to Haratym? |
| 3:52:17 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Present when colleage ??? |
| 3:52:29 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cost of bundles modeled year spent? |
| 3:52:37 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | And bundles contain ???, Huber stated provided that information, true that savings were accounted for in modeling from efficiency bundles only to end of IRP period? |
| 3:54:32 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Costs leveled over full year of service life of efficiency measures? |
| 3:55:37 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Even if extends beyond IRP planning period? |
| 3:56:33 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Modeling of renewable resources in IRP, turning to page 94, section 5.4.1 modeling of wind resource, second paragraph, states ??? |
| 3:57:35 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | There are two pricing tiers, Tier 1 and Tier 2, maxiumum annual capacity is ??? |
| 3:58:02 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cumulative over entire modeling period? |
| 3:58:18 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | For solar, Tier 1 and Tier 2 for solar resources, 50 MW, maximum 150 MW ??? |
| 3:58:56 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | And also cumultative over course of IRP period? |
| 3:59:12 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | In terms of modeling ???? |
| 3:59:28 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Some of those moedling runs do hit maximums discussing? |

| | | |
|---|---|---|
| 4:00:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | Page 219, high cost portfolio? |
| 4:00:11 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Total under wind does meet 1200 MW number? |
| 4:00:22 PM | Session Note Entry | |
| | Note: Sacre, Candace | Enhabced carbon ???? |
| 4:00:31 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Says 150/300? |
| 4:00:52 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Those were annual maximums just discussing for solar? |
| 4:01:18 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Review comments from Commission Staff? |
| 4:01:27 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Turn to page 113 of IRP, section 5 response to Staff comments, look at No. 8 at bottom ??? |
| 4:02:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | Should model ???? |
| 4:02:20 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | In response, company maintains of running model without constraints, not provide further insights? |
| 4:02:48 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | That refers to fact in some scenarios not hit restraints? |
| 4:03:35 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | In those two portfolios, not know what model would have selected? |
| 4:03:52 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | And the solar? |
| 4:04:04 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cost assumptioins, on page 124 of IRP, summarizes assumptions that vary in each of portfolios? |
| 4:05:25 PM | Session Note Entry | |
| | Note: Sacre, Candace | The baseline assumptions for ??? |
| 4:05:46 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | What different slower decline? |
| 4:05:53 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Slower decline cost of building ??? |
| 4:06:09 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Different assumptions for all ???? |
| 4:06:46 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | ??? solar wind and storage? |
| 4:07:04 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Not Big Sandy costs ??? |
| 4:07:19 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Costs for new supply resources also subject to supply chain shock? |
| 4:08:13 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Would cost of steel and cost of cement and concrete relevant for new gas assumptions ??? |
| 4:09:36 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Looked at whether those types of inputs subject to inflationary pressure higher than regular inflationary pressure? |
| 4:10:59 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Not run similar cost scenario for gas resources? |
| 4:11:20 PM | Session Note Entry | |
| | Note: Sacre, Candace | Here earlier when Cmar asking West about ???? |

| | | |
|---|---|---|
| 4:11:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Referred some questions to you? |
| 4:11:56 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Understanding energy community tax credit eligible in communities that qualify as energy community? |
| 4:12:21 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Some of relevant criteria for determination is coal plant closure? |
| 4:12:44 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Also metric related to unemployment rates? |
| 4:13:03 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | West saying energy community tax credit bonus not ??? |
| 4:13:35 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Specifically up to ten percent? |
| 4:13:52 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Looked into how much of Kentucky Power territory qualify for energy bonus? |
| 4:14:14 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Relevant to resource planning whether resource might be eligible? |
| 4:16:00 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | If able to assess large footprint eligible for bonus, in next IRP relative ???? |
| 4:17:58 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | PTC and ITC both wind and solar are eligible for energy community bonus? |
| 4:18:35 PM | Session Note Entry | |
| | Note: Sacre, Candace | Distributed energy resources not modeled as part of ??? |
| 4:18:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | How long been with AEP? |
| 4:19:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | Inovblve in Knetucky Power 2020 rate case? |
| 4:19:11 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Reviewed Order from that case on net metering? |
| 4:19:30 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Want to pull up that Order relevant passage to modeling supply side resources? |
| 4:19:39 PM | Via Presentation Activated | |
| 4:20:02 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | Objection. (Click on link for further comments.) |
| 4:20:04 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cross Examiantion (cont'd). Case No. 2020-00174 Kentucky Power rate case from May 2021, refers to tariff, resolves issues related to NMS, net metering tariff, page 21, familiar with term customer generators? |
| 4:22:04 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Customers that take service under net metering tariff? |
| 4:22:18 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Sentence begins, reading (click on link for further comments)? |
| 4:22:52 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | No context for witness not familiar with case. (Click on link for further comments.) |
| 4:23:16 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Bullet point 1, reading (click on link for further comments), IRP compares energy resources according to availability to meet system needs for capacity ??? |

| | | |
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| 4:25:20 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | In terms of principle of evaluating ???, that was not done in this IRP? |
| 4:25:45 PM | Via Presentation Deactivated | |
| 4:26:13 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Review energy futures report that was attached to Joint Intervenors ???? |
| 4:26:34 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Review recommendations? |
| 4:27:07 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Recall discussion of Northern Indiana Service Company? |
| 4:27:30 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Discussion in reference to NISCo ??? |
| 4:27:54 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Recess until 4:45. |
| 4:29:09 PM | Session Paused | |
| 4:48:35 PM | Session Resumed | |
| 4:49:09 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on the record. |
| 4:49:25 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Counsel? |
| 4:49:31 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Cross Examination (cont'd). Input workbook for modeling and AURORA outputs, something you can? |
| 4:50:00 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | PTC and ITC know referring to production tax credit and ????, report attached to Joint Intervenor comments, have that? |
| 4:50:55 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | How tax incentives modeled, company provided parties copy of input workbook? |
| 4:51:36 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Joint Intervenors 1-6, Attachment 1, tax gross up? |
| 4:51:55 PM | Atty Legge Joint Intervenors - witness Soller | |
| | Note: Sacre, Candace | Explain what tax gross up is? |
| 4:53:12 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Questions? |
| 4:53:29 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Cross Examination. Supply side resources and how chosen, process involved and who involved, you involved? |
| 4:53:59 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | How start out and various constraints? |
| 4:56:54 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Who is we, just your group or multiple groups involved? |
| 4:58:30 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Before take to Kentucky Power, ??? for screening, how is that process? |
| 4:59:36 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Specific written criteria? |
| 4:59:54 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Discuss those resources with them and more culling of the list? |
| 5:01:38 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Who makes ultimate decision what resources included in modeling? |

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| 5:02:09 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Natural gas combined cycle limited to 1083 MW unit and 418 MW, various sizes, particular reason limited to 1083 and 418? |
| 5:04:11 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Add significant time to modeling runs to add ???? see if model selects various sizes, how much time? |
| 5:05:02 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | With respect to simple cycle ???, what was thinking behind placing that constraint on model? |
| 5:06:14 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Have IRP? |
| 5:06:24 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Page 90, simple cycle combustion turbines, Table 6, top of page 90, VOM variable operations and maintenance costs? |
| 5:07:00 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Is that ??? |
| 5:07:08 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Start costs of ???? combustion turbine? |
| 5:08:25 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Table 7, page 91, variable operations and maintenance expense for ???, area where is? |
| 5:08:52 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | VOM on page ??? 267 per MWh? |
| 5:09:09 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Curoius why VOM for single cycle low, ??? more efficient? |
| 5:09:24 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Expect variable cost for simple cycle combustion turbine ??? |
| 5:10:30 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Examination. Have start-up costs, incurred once regardless of number of hours? |
| 5:10:47 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | VOM based on number of starts or ??? |
| 5:11:54 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Insofar as recurring capital costs, reflected in start-up costs? |
| 5:12:14 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Steam units, may do eight-year cycle? |
| 5:12:34 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Turbine overhauls not necessarily reflection of ???, far more about with a CT operation of facility? |
| 5:13:00 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Where in modeling is ???, not VOM? |
| 5:13:30 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Sure not in start-up costs? |
| 5:13:45 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Where would you have included it? |
| 5:14:25 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Separately with combined cycle ??? |
| 5:14:39 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Steam portion recurring based on number of years? |
| 5:14:54 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Both included separately insofar as ramping of unit on economic basis and impact has on turbine and need for capital maintenance? |

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| 5:15:45 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Operation of facilities once chosen, permit units to be dispatched economically as if just an energy resource in PJM market? |
| 5:16:29 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Is it being run as if part of PJM universe or part of exclusively Kentucky Power universe? |
| 5:17:08 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | As Kentucky Power system, 800 MW of solar, have less production in solar and ramp up units ??? |
| 5:17:37 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Require unit to ramp when required, still need ramping once 800 MW solar stopped production need to be corresponding 800 to ramp? |
| 5:18:17 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Fact do it in PJM universe very diffferent ??? |
| 5:18:34 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Other economical incentives than ??? |
| 5:18:46 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Mr. Bellamy? |
| 5:18:52 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Cross Examination (cont'd). Explanation of difference in both those costs? |
| 5:19:23 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Page 44 of IRP, Table ???, how modeling conducted, wanted to point you to that, got AURORA portfolio module, referring to capacity expansion modeling or capacity optimization? |
| 5:20:26 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Discussion of reference portfolio, started out as five scenarios? |
| 5:21:00 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Not clear if regional analysis or ??? run together, but run separately? |
| 5:21:20 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | ??? able to explain ??? |
| 5:21:36 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | PJM optimizationi complete? |
| 5:21:52 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Scenarios put in AURORA capacity ????? |
| 5:22:05 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Spits our portfolios that go by same name? |
| 5:22:17 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Two more run as ??? |
| 5:22:28 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | No wind and ??? optimization? |
| 5:22:40 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Natural gas combined cycle run reference case with combined cycle locked in? |
| 5:23:01 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Prohibited it from selecting wind? |
| 5:23:48 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | With respect to ???, explanation what was solving for? |
| 5:25:46 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Understand other constraints, ultimately in solving for least cost based on ??? |
| 5:26:11 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Solving for least cost within planning period? |

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| 5:26:48 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Looking at revenue requirement effect of each resource? |
| 5:27:05 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Looking at gas resource, look at ??? |
| 5:27:32 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Carrying charge for high capital cost asset beginning of life more expensive ??? |
| 5:28:32 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Saying carrying cost, cost of capital each year, not decreasing based on net plant in service ???? |
| 5:29:46 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Averaging carrying costs over life of asset? |
| 5:30:08 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Mean percentage are appllying? |
| 5:30:23 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Single value applied to same capital cost each year? |
| 5:30:37 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Examination. Levelized a more accurate description? |
| 5:31:10 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Total nominal cost, initial upfront cost, cost in between? |
| 5:32:01 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Return on and return off levelized over entire year? |
| 5:32:24 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Cross Examination (cont'd). Haratym have more ??? |
| 5:32:55 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | First AURORA step, Kentucky Power not have ??? |
| 5:34:15 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | All taking place in first cylinder on Figure 66 and selecting portfolio as well as market purchases least cost? |
| 5:34:51 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Modeling of energy purchases if had solar and model knows winter load be X and make market purchases, during AURORA optimization ??? |
| 5:36:10 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Beyond first step and now have portfolios for various scenarios, moving to financial model and applying assessment criteria, KIUC Exhibit 1, fourth page is table showing evaluation with assessment criteria, short-term five-year cost and CTW, costs coming from revenue requirement calculations second cylinder on Figure 66? |
| 5:41:30 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | With respect to five-year cost calculation and ??? |
| 5:42:34 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | With the 15-year for unit have high capital cost, only have seven or eight years to depreciate at end of analysis, correct? |
| 5:43:35 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Understanding just did revenue cost calculation, think went out further? |
| 5:44:12 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Going back to looking at resources, in this case, not reach out to any other utilities in service area regarding going together on any particular resource? |
| 5:44:57 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Investigate with utilities or own investigation possibility of partnering with them particular resource? |

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| 5:45:58 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Review IRPs and IRP reports for other utilities in Kentucky? |
| 5:46:23 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Surpirse you that several other utilities in Kentucky might have interest in partnerships with other entities? |
| 5:46:57 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | One of costs carrying costs, going to have debt cost and cost of equity, for large resource significant? |
| 5:47:29 PM | Session Note Entry | |
| | Note: Sacre, Candace | Familiar with financing opportunities to electric transmission and geneaton cooperatives? |
| 5:47:54 PM | Session Note Entry | |
| | Note: Sacre, Candace | Typically have lower ???? |
| 5:48:03 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Know where East Kentucky Power located? |
| 5:48:15 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Page 240 of IRP, table on that page, column says energy surplus, positive in some and negative in others, preferred plan ??? scenario, be possible break out by month and how netting out? |
| 5:49:27 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | IRP at page 40 had to do with load discussion of seven load scenarios, high and low and base, know where tie in to five scenarios ran? |
| 5:50:39 PM | Asst Gen Counsel Bellamy PSC - witness Soller | |
| | Note: Sacre, Candace | Know which one you switched? |
| 5:51:06 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Examination. Best person ask about determination of rate stability to achieve objectives? |
| 5:51:46 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Four categories on score card ??? |
| 5:51:58 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Four metrics overall? |
| 5:52:28 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Cost risk, revenue requirement, walk me through that? |
| 5:53:28 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Market exposure, described as net sales ??? |
| 5:53:43 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Sumer and winter percentage? |
| 5:54:04 PM | Session Note Entry | |
| | Note: Sacre, Candace | Scenario 250 ??? |
| 5:54:15 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | What universe of ??? |
| 5:55:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | A portfolio results in positive percentage is one in which the utility selling more energy than consuming? |
| 5:55:37 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 5:55:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Relative to its own internal demand? |
| 5:55:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | Thirty percent winter ???? |
| 5:56:01 PM | Session Note Entry | |
| | Note: Sacre, Candace | Average basis across scenarios? |

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| 5:56:08 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Given scenario range and cost of risk, what purported benefit looking at market exposure? |
| 5:57:40 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Have a rule of thumb market exposure what unreasonable risk both ways, have collar there? |
| 5:59:00 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Put constraint on it every dollar in excess of 30 percent reflected in net sales ???? |
| 6:00:11 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Know what Kentucky Power market exposure is today? |
| 6:00:27 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Something readiily available? |
| 6:00:45 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Mitchell capacity midyear ??? , how modeled? |
| 6:01:05 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Model made Kentucky Power buy enough capacity replace Mitchell in 2028-29? |
| 6:01:26 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Mitchell stayed AEP zone, model assume nobody got 700 MW at Mitchell or just got first seven months free? |
| 6:01:58 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Someone other than Kentucky Power, what model represented? |
| 6:02:17 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | Worst case scenario for cost of replacement capacity in that IRP assumed no value? |
| 6:02:45 PM | Chairman Chandler - witness Soller | |
| | Note: Sacre, Candace | $15 millon cost for capacity in that year? |
| 6:03:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | Counsel? |
| 6:03:12 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Redirect Examination. Value of transmission costs since represented in modeling, recall asked about whether model took into consideration ???? |
| 6:03:52 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Explained that resources are generic and ??? |
| 6:04:34 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | ??? |
| 6:05:05 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Expectation that specific resources would costs show up in cost of resources all in? |
| 6:05:45 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | For IRP purposes, not select specific resources but what are optimal resources? |
| 6:06:11 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Asked about collaboratioin with other utilities, indicated IRP analysis ???, exclude resources jointly owned? |
| 6:07:28 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Regardless of jointly owned or owned by Kentucky Power? |
| 6:07:43 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | IRP did not include other than ownerhip of Mitchell did not have hard assumption about shared resources? |
| 6:08:11 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Asked about costs for Mitchell reflected in IRP, modeling not reflect how costs be treated in reality? |

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| 6:08:38 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Another witness address how costs treated in practice? |
| 6:08:51 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Were asked ELCC changes in PJM after assumptions of IRP ??? |
| 6:09:16 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Counsel asked and you clarified not constrained to only one type of resource ??? |
| 6:09:46 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Does IRP take into consideration ??? |
| 6:10:48 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | Be similar to effect in IRP high carbon cost scenario changes in environmental rule something IRP ??? |
| 6:11:45 PM | Atty Garcia Santana Kentucky Power - witness Soller | |
| | Note: Sacre, Candace | For purposes of proposed plan, accounts for things unknown in future and tries to find resources that are lowest cost provide reliable service? |
| 6:12:20 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Anything else? |
| 6:12:58 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Recess until 6:20. |
| 6:13:17 PM | Session Paused | |
| 6:27:05 PM | Session Resumed | |
| 6:27:10 PM | Vice Chairman Hatton | |
| | Note: Sacre, Candace | Back on the record. |
| 6:27:27 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next witness? |
| 6:28:13 PM | Session Note Entry | |
| | Note: Sacre, Candace | Thomas Haratym. |
| 6:28:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 6:28:27 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examiantion. Name and address? |
| 6:28:40 PM | Session Note Entry | |
| | Note: Sacre, Candace | Bye chomw employed and in whart capacity? |
| 6:28:49 PM | Session Note Entry | |
| | Note: Sacre, Candace | Provide services to Kentucky Power? |
| 6:28:56 PM | Atty Garcia Santana Kentucky Power - witness Haratym | |
| | Note: Sacre, Candace | What were those services? |
| 6:29:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | Have ??? |
| 6:29:27 PM | Session Note Entry | |
| | Note: Sacre, Candace | Provide responses? |
| 6:29:36 PM | Session Note Entry | |
| | Note: Sacre, Candace | If were to ask same questions, answers be same? |
| 6:29:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Mr. West? |
| 6:30:02 PM | Asst Atty General West - witness Haratym | |
| | Note: Sacre, Candace | Cross Examination. Have IRP? |
| 6:30:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Turn to Section 6.5.2, ELCC results, read second paragraph there? |
| 6:31:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Others talked about ELCC, 54 percent value, what is that number? |
| 6:32:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | Familiar what happened since IRP filed? |

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| 6:33:28 PM | Session Note Entry | |
| | Note: Sacre, Candace | Seen this document before? |
| 6:33:35 PM | Session Note Entry | |
| | Note: Sacre, Candace | Turn to page 5, Table 3 talks about changes just referencing ELCC class values for solar, see that? |
| 6:34:11 PM | Session Note Entry | |
| | Note: Sacre, Candace | Page 8, representation of same data, IRP ELCC decline to levels ??? |
| 6:34:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | What is graph showing values to be? |
| 6:35:08 PM | Session Note Entry | |
| | Note: Sacre, Candace | Agree 17 percent lower than 27 percent ELCC value referenced? |
| 6:35:31 PM | Session Note Entry | |
| | Note: Sacre, Candace | Effectively mean would need to install more solar to achieve same amount of service? |
| 6:35:50 PM | Session Note Entry | |
| | Note: Sacre, Candace | Relative to assumptions made in IRP, projecting lower capacity value? |
| 6:36:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | What value imply to you? |
| 6:37:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Related to fact intermittent in nature? |
| 6:38:01 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? |
| 6:38:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Distinguishable because ??? |
| 6:39:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Fairly new document, relates to same concepts ELCC updates published by PJM regularly, aware routinely publish ELCC values? |
| 6:40:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | If flip to page 5 of this document, showing ELCC values over period of time, 2034-2035, table includes value in additionl to solar, see that? |
| 6:40:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | What are ??? |
| 6:41:05 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | No foundation. (Click on link for further comments.) |
| 6:41:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | Summarize what going on tracking solar for period referenced in chart? |
| 6:41:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | From what value to what value? |
| 6:42:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Four percent value in 2034-35 than six percent in ???? |
| 6:42:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | If look at nuclear coal ??? and values, reference made earlier ELCC for those declining over time, find that to be the case listed there? |
| 6:43:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | If Kentucky Power proposing install 700 MW solar, now need to install maybe ten times as much, affect cost feasibility? |
| 6:44:03 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | Inclined to admit them on some other basis, not provide foundation. |
| 6:44:50 PM | Session Note Entry | |
| | Note: Sacre, Candace | Admit AG i1 and 2 noting objection. |
| 6:45:02 PM | Session Note Entry | |

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|---|---|---|
| 6:45:06 PM | Session Note Entry | |
| 6:45:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Mr. Kurtz? |
| 6:45:26 PM | Atty Kurtz KIUC - witness Haratym | |
| | Note: Sacre, Candace | Cross Examination. Refer to ???, short term cost of ??? |
| 6:45:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next column ??? |
| 6:46:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Correct, on ???? |
| 6:46:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | No wind portfolio invest ??? |
| 6:47:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | No wind invest $733 million in Kentucky versus preferred plan? |
| 6:47:24 PM | Session Note Entry | |
| | Note: Sacre, Candace | What accounts for additional investment in Kentucky? |
| 6:48:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | More construction jobs in Kentucky, more ??? |
| 6:48:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | Mr. Gary? |
| 6:48:24 PM | Atty Legge Joint Intervenors - witness Haratym | |
| | Note: Sacre, Candace | Cross Examination. Ask about AG Exhibit 2, page 6, wind more robust than compared to assumptions in IRP, 11 percent was assumption? |
| 6:49:37 PM | Session Note Entry | |
| | Note: Sacre, Candace | PJM looking at about 35 percent? |
| 6:49:56 PM | Session Note Entry | |
| | Note: Sacre, Candace | As long as fule there and resource shows up? |
| 6:50:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Believe response was as long as plant in good condition? |
| 6:50:22 PM | Session Note Entry | |
| | Note: Sacre, Candace | Fuel available not only cause of forced outage? |
| 6:50:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Return to levelized costs, here when Soller talking about levelized cost of energy efficience bundles? |
| 6:50:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | Costs are modeled as spent in year one but model takes into account the full life of efficiency ??? |
| 6:51:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Tell us where in the file that is, we can find that information? |
| 6:51:37 PM | Session Note Entry | |
| | Note: Sacre, Candace | Where is it noted that energy efficiency measures ??? |
| 6:52:08 PM | Session Note Entry | |
| | Note: Sacre, Candace | Be amenable to post-hearing data request? |
| 6:52:25 PM | Atty Glass Kentucky Power | |
| | Note: Sacre, Candace | Yes, we would. |
| 6:52:48 PM | POST-HEARING DATA REQUEST | |
| | Note: Sacre, Candace | ATTY LEGGE JOINT INTERVENORS - WITNESS HARATYM |
| 6:53:28 PM | Session Note Entry | |
| | Note: Sacre, Candace | ????, recall that? |
| 6:53:50 PM | Session Note Entry | |
| | Note: Sacre, Candace | Refer to Energy Efficiency Group, review that report? |
| 6:54:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | But did review it in course of work? |

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| 6:54:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | As discussing earlier, workbook reflects tax gross up? |
| 6:54:51 PM | Private Mode Activated | |
| 6:54:51 PM | Private Recording Activated | |
| 6:55:53 PM | Via Presentation Activated | |
| 7:01:56 PM | Via Presentation Deactivated | |
| 7:02:28 PM | Normal Mode Activated | |
| 7:02:28 PM | Public Recording Activated | |
| 7:03:04 PM | Session Note Entry | |
| | Note: Sacre, Candace | Counsel? |
| 7:03:11 PM | Asst Gen Counsel Bellamy PSC - witness Haratym | |
| | Note: Sacre, Candace | Cross Examination. Copy of IRP? |
| 7:03:22 PM | Session Note Entry | |
| | Note: Sacre, Candace | Table 6 which is cost for simple cycle combustion turbine, looking at variable operation maintenance cost, 62 cents per MWh for natural gas combustion turbine, on page 88 VOM for natural gas combined cycle is $2.67 per MWh, why lower? |
| 7:05:47 PM | Session Note Entry | |
| | Note: Sacre, Candace | Simple cycle has ??? taken out, included elsewhere? |
| 7:06:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | Page 144 of IRP, chart shows flow of modeling, Figure 66, have that? |
| 7:06:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | First cylinder, resource optimization model selecting resources for five scenarios? |
| 7:07:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Have all constraints, ultimately solving for lowest cost portfolio meeting various conditions? |
| 7:07:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | How determining lowest cost, 15 years or longer period of time? |
| 7:08:20 PM | Session Note Entry | |
| | Note: Sacre, Candace | Comparing resource over 30 years against multiple resources at any given time? |
| 7:08:54 PM | Session Note Entry | |
| | Note: Sacre, Candace | Is there load projected all the way out to end of life of ??? unit selected? |
| 7:09:36 PM | Session Note Entry | |
| | Note: Sacre, Candace | Confused about, how doing that over longer period if not projecting load and optimizing? |
| 7:10:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Post-hearing data request asking for clarification. |
| 7:10:48 PM | POST-HEARING DATA REQUEST | |
| | Note: Sacre, Candace | ASST GEN COUNSEL BELLAMY PSC - WITNESS HARATYM |
| 7:10:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | Second part of analysis, long-term 15 PCW reference case, calculating revenue requirement any tier over 15-year period, lowest ??? |
| 7:11:37 PM | Session Note Entry | |
| | Note: Sacre, Candace | Second one, long term? |
| 7:12:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? |
| 7:12:15 PM | Session Note Entry | |
| | Note: Sacre, Candace | And how ??? over each year? |

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| 7:12:29 PM | Session Note Entry | |
| | Note: Sacre, Candace | Resource optimization step in Aurora, ??? and making short-term energy ??? |
| 7:13:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? check to see if ??? |
| 7:14:02 PM | Session Note Entry | |
| | Note: Sacre, Candace | When model requesting that, is it an hourly price? |
| 7:14:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Changing every hour based on expected load all of PJM and reliability within PJM? |
| 7:14:58 PM | Session Note Entry | |
| | Note: Sacre, Candace | Discussion two-part analysis before Figure 66 projecting resource decisions within PJM, all done before you introduced ??? |
| 7:15:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Was resources available within PJM when ran optimizaton for PJM, limited to same resources Kentucky Power limited to? |
| 7:16:13 PM | Chairman Chandler - witness Haratym | |
| | Note: Sacre, Candace | Examination. ELCC have documents West gave you? |
| 7:16:31 PM | Session Note Entry | |
| | Note: Sacre, Candace | Big change between what ran? |
| 7:16:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Very fun stakeholder meeting on June 4 what underlying assumptions in AG 2, ???? see that? |
| 7:17:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | Good appreciation for ELCC as a concept? |
| 7:17:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | If model produced ELCC only ??? |
| 7:17:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not put all weight on winter, but if decrease ??? |
| 7:18:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Opposite direction, if increase weight of hours, increase ELCC? |
| 7:18:31 PM | Session Note Entry | |
| | Note: Sacre, Candace | If model takes into account risk of correlated outage based on unreliable transportation ??? |
| 7:19:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not touching supply side, ELCC, customers tend to start increasing demand of power in middle of afternoon days, shifting usage from other hours to noon hours in summer, increase or decrease ELCC? |
| 7:20:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | Assuming increase in demand increases ??? |
| 7:20:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | How much stock put in ??? |
| 7:21:48 PM | Session Note Entry | |
| | Note: Sacre, Candace | Capacity is not consumed to keep lights on and ??? |
| 7:22:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Utilized to produce energy? |
| 7:22:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not ability to produce it but actual production? |
| 7:22:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | How much value give IRP to meet a system-wide resource construct verse ability ??? |
| 7:23:13 PM | Session Note Entry | |
| | Note: Sacre, Candace | From your perspective, IRP conducted with eye toward meeting Kentucky Power of requirements in PJM or meet obligations serve native load? |

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| 7:24:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | As related to ELCC capaciaty accreditation meeting PJM requirements consideration or ??? |
| 7:24:47 PM | Session Note Entry | |
| | Note: Sacre, Candace | Applying to resources using for latter but not running ELCCs on ??? basis? |
| 7:25:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not a locational aspect to ELCC? |
| 7:25:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | Locational benefit to having generation within the footprint of Kentucky Power? |
| 7:25:40 PM | Session Note Entry | |
| | Note: Sacre, Candace | If massive imbalance within subzone between demand and load, does that risk anomalous energy outcomes? |
| 7:26:22 PM | Session Note Entry | |
| | Note: Sacre, Candace | Does IRP look at all whether or not retirement of local generation to generation not local, any price impact of that not looked at? |
| 7:27:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | LDA load specific? |
| 7:27:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Recess until 8 pm. |
| 7:27:47 PM | Session Paused | |
| 8:00:36 PM | Session Resumed | |
| 8:01:08 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Back on the record. |
| 8:01:42 PM | Session Note Entry | |
| | Note: Sacre, Candace | Redirect? |
| 8:02:18 PM | Session Note Entry | |
| | Note: Sacre, Candace | Ms. Glass? |
| 8:02:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | Stephen Blankenship. |
| 8:02:36 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 8:02:43 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 8:02:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | Direct Examination. Positioin and employer? |
| 8:03:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Data reqeusts? |
| 8:03:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Corections? |
| 8:03:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | If asked same questions, reply the same? |
| 8:03:29 PM | Session Note Entry | |
| | Note: Sacre, Candace | Questions? |
| 8:03:42 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next witness? |
| 8:03:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kamran Ali. |
| 8:04:04 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 8:04:14 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examination. Name and address? |

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| 8:04:26 PM | Atty Garcia Santana Kentucky Power - witness Ali | |
| | Note: Sacre, Candace | Direct Examination. By whom employed and capacity? |
| 8:04:42 PM | Session Note Entry | |
| 8:04:47 PM | Session Note Entry | |
| 8:04:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Corrections? |
| 8:04:58 PM | Session Note Entry | |
| | Note: Sacre, Candace | If were to ask questions today, answers be same? |
| 8:05:06 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Mr. Kurtz? |
| 8:05:16 PM | Atty Kurtz KIUC - witness Ali | |
| | Note: Sacre, Candace | Cross Examination. Describe Big Sandy and condition it is in? |
| 8:05:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | That plant used to have 800 MW coal plant? |
| 8:05:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | Site accommodate 800 MW new generation? |
| 8:06:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? |
| 8:07:27 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Mr. Gary? |
| 8:07:47 PM | Atty Gary Joint Intervenors - witness Ali | |
| | Note: Sacre, Candace | Cross Examination. Matter if 800 MW came from ???, is it resource agnostic? |
| 8:08:25 PM | Session Note Entry | |
| | Note: Sacre, Candace | Big Sandy capable of hosting 800 MW battery? |
| 8:08:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | And analysis same as for CCR or CT? |
| 8:09:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Essentially? |
| 8:09:40 PM | Chairman Chandler - witness Ali | |
| | Note: Sacre, Candace | Examination. Asked questions about Big Sandy substation accommodate this or accommodate that, maybe but not studied, whether substation can take or have ??? |
| 8:10:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Two completely different analysis? |
| 8:10:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Would do latter study when somebody puts in for the queue, what is effect of generator generating energy, seeking to interconnect as a resource? |
| 8:11:37 PM | Session Note Entry | |
| | Note: Sacre, Candace | Agree at least two distinct studies that have to be done, what violations may occur from me connecting to broader system? |
| 8:12:01 PM | Session Note Entry | |
| | Note: Sacre, Candace | If generator want ??? |
| 8:13:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | Is AEP or Kentucky Power in position to study feasibility or impact of connection without seeking to enter the queue? |
| 8:14:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Two types of studies, one where impact connection has on broader system verse physical ability connect to system, given idea of queue how interconnects together, hard to do with certainty, is there still lack of certainty studying physical capability of attaching to substation? |

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| 8:15:35 PM | Session Note Entry | |
| | Note: Sacre, Candace | From all testimony idea is relates to IRP ignore transmission cost, ??? brown field sites where ??? |
| 8:16:24 PM | Session Note Entry | |
| | Note: Sacre, Candace | Directional aspect similar what asking Harratym about locational aspect of facilities and load and generation? |
| 8:17:03 PM | Session Note Entry | |
| | Note: Sacre, Candace | When somebody enters queue and on your system, PJM depends on you do legwork on what impact might be? |
| 8:18:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | If needs identified, determine solution to meet need? |
| 8:18:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | Have different ??? |
| 8:18:35 PM | Session Note Entry | |
| | Note: Sacre, Candace | If affiliate, ask operating company on getting input what position is on appropriate solution? |
| 8:19:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Solution could be reconductoring or complete reconfiguration, two possible options? |
| 8:20:14 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kentucky Power seeking to interconnect ??? |
| 8:21:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Have final call with what to go with? |
| 8:21:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | Whose call is it at very end, the final say? |
| 8:22:57 PM | Session Note Entry | |
| | Note: Sacre, Candace | By definition is your call? |
| 8:23:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | In advance of capacity auctions, certain risk parameters studied as relates to SETO not within your ??? |
| 8:24:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | SETL that is LDA or sub-LDA deterimination? |
| 8:24:27 PM | Session Note Entry | |
| | Note: Sacre, Candace | Any given year mismatch and generation available within zone or transfer limitation insofar as there becomes a mismatch reflected in increased capacity price for that zone? |
| 8:25:33 PM | Session Note Entry | |
| | Note: Sacre, Candace | How close is AEP zone from being able to not meet obligations? |
| 8:26:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | If all of a sudden 3000??? MW demand, study will be conducted? |
| 8:27:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Expecting thousands of megawatts retirement between now and 2028, and within AEP zone specifically requests for new connections for load? |
| 8:28:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Those things combined and interconnection requests for demand? |
| 8:28:29 PM | Session Note Entry | |
| | Note: Sacre, Candace | Given those two things to go both ways in degrading calculation referring to, when appropriate time to start looking at and taking into consideraton location of generation ??? |
| 8:29:46 PM | Session Note Entry | |
| | Note: Sacre, Candace | ELCC not locational, correct? |
| 8:29:58 PM | Session Note Entry | |
| | Note: Sacre, Candace | AEP winter peaking or summer peaking? |

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| 8:30:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kentucky Power winter peaking? |
| 8:30:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not know what zone for which season? |
| 8:30:29 PM | Session Note Entry | |
| | Note: Sacre, Candace | DPL South issue occurred last year? |
| 8:30:46 PM | Session Note Entry | |
| | Note: Sacre, Candace | Insofar as SETO/SETL over mismatch winter phenomenon, when highest risk is, addition of solar not necessarily benefit mismatch, not alleviate binding constraint? |
| 8:32:19 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not taken into account at all in ??? |
| 8:32:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Heard questions to West about outstanding request for proposal? |
| 8:33:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kentucky Power issued three requests for proposal? |
| 8:33:20 PM | Session Note Entry | |
| | Note: Sacre, Candace | What the request is to meet requirements of RFP, reading (click on link for further comments), number of studies for generator to connect to PJM? |
| 8:34:05 PM | Session Note Entry | |
| | Note: Sacre, Candace | System impact study? |
| 8:34:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | How far along the path is system impact study? |
| 8:34:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Accurate to say halfway through queue if had system impact study, where along in queue process? |
| 8:35:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Once have completed study, how far along in process? |
| 8:36:24 PM | Session Note Entry | |
| | Note: Sacre, Candace | Does a completed system impact study already conducted affected system studies? |
| 8:36:51 PM | Session Note Entry | |
| | Note: Sacre, Candace | Perspective of LG&E/KU system, impact study connect AEP system, mean have already done affected system study? |
| 8:37:32 PM | Session Note Entry | |
| | Note: Sacre, Candace | Seen studies that say problems on LKE system, get affected systems study done, done in context of SIS? |
| 8:38:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not mean same entity received back an affected system study? |
| 8:38:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | Treat all PJM as single system? |
| 8:38:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | Have input into rubric for request for proposals as relates to ??? |
| 8:39:02 PM | Session Note Entry | |
| | Note: Sacre, Candace | Told to ask Pearce about rubric ???? |
| 8:39:28 PM | Atty Garcia Santana Kentucky Power | |
| | Note: Sacre, Candace | Cannot disclose ???? |
| 8:40:00 PM | Session Note Entry | |
| | Note: Sacre, Candace | ????? |
| 8:40:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | Somebody be on scoring team or if have questions come and ask questions, what level of involvement ??? |

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| 8:41:33 PM | Session Note Entry | |
| | Note: Sacre, Candace | Just do ???? |
| 8:41:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Redirect? |
| 8:41:53 PM | Session Note Entry | |
| | Note: Sacre, Candace | Next witness? |
| 8:41:59 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kelly Pearce. |
| 8:42:04 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 8:42:12 PM | Atty Gish Kentucky Power - witness Pearce | |
| | Note: Sacre, Candace | Direct Examination. Position and full title? |
| 8:42:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Involved in IRP? |
| 8:42:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Involved in ??? |
| 8:43:44 PM | Atty Cmar Joint Intervenors - witness Pearce | |
| | Note: Sacre, Candace | Cross Examination. Questions that came up with West, here for that? |
| 8:44:01 PM | Session Note Entry | |
| | Note: Sacre, Candace | One question related to PJM procurement of capacity delivery yeaer '26-'27, when Kentucky Power need to make decisions whether purchase capacity? |
| 8:44:56 PM | Session Note Entry | |
| | Note: Sacre, Candace | What say happen in December? |
| 8:45:08 PM | Session Note Entry | |
| | Note: Sacre, Candace | Kentucky Power decided bilateral contracts, same time frame? |
| 8:46:00 PM | Private Mode Activated | |
| 8:46:00 PM | Private Recording Activated | |
| 8:52:24 PM | Session Paused | |
| 9:03:29 PM | Session Resumed | |
| 9:04:36 PM | Normal Mode Activated | |
| 9:04:36 PM | Public Recording Activated | |
| 9:04:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | Questions? |
| 9:04:48 PM | Chairman Chandler - witness Pearce | |
| | Note: Sacre, Candace | Examination. Familiar with 2023 RFPs? |
| 9:05:12 PM | Session Note Entry | |
| | Note: Sacre, Candace | Statement in those that says, reading (click on link for further comments), although storage and ???, all need system impact study, read this portion of RFP to mean already need to be or intention to be interconnected to PJM? |
| 9:06:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Read that as a requirement at the time when respond? |
| 9:07:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | RFP for resources already inconnected to PJM at time apply? |
| 9:07:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Says it as if not must be planning to connect to PJM, not for generators with a signed agreement way past SIS point, or supposed to be connected to PJM as opposed to different ??? |
| 9:09:45 PM | Session Note Entry | |
| | Note: Sacre, Candace | Idea behind site control and ESI, financing plan, remember that? |

| | | |
|---|---|---|
| 9:10:10 PM | Session Note Entry | |
| | Note: Sacre, Candace | Scoring rubrics, in a general matter, AEP operating company what scoring rubric be or general one? |
| 9:10:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Ask as post-hearing data request latest scoring rubric not scoring projects just most recently used rubric? |
| 9:11:45 PM | POST-HEARING DATA REQUEST | |
| | Note: Sacre, Candace | CHAIRMAN CHANDLER - WITNESS PEARCE |
| 9:12:07 PM | Session Note Entry | |
| | Note: Sacre, Candace | RFP responses, all due on the same day to three different? |
| 9:12:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | All being looked at seprately, all in same bucket, solar bucket, wind bucket ??? |
| 9:13:25 PM | Session Note Entry | |
| | Note: Sacre, Candace | If IRA passes, inflationi reduction act comes out, battery affected by change, wind would, solar would, thermal would, just be holding up third bucket for other two, reasonable explanation of distinction made? |
| 9:15:09 PM | Session Note Entry | |
| | Note: Sacre, Candace | Response there relative to other two buckets? |
| 9:15:33 PM | Session Note Entry | |
| | Note: Sacre, Candace | Redirect? |
| 9:15:44 PM | Session Note Entry | |
| | Note: Sacre, Candace | Anything else? |
| 9:15:50 PM | Session Note Entry | |
| | Note: Sacre, Candace | Call last witness? |
| 9:15:56 PM | Session Note Entry | |
| | Note: Sacre, Candace | Alex Vaughan. |
| 9:16:05 PM | Session Note Entry | |
| | Note: Sacre, Candace | Witness is sworn. |
| 9:16:11 PM | Session Note Entry | |
| | Note: Sacre, Candace | Examination. Name and address? |
| 9:16:26 PM | Atty Gish Kentucky Power - witness Vaughan | |
| | Note: Sacre, Candace | Direct Examination. Title??? |
| 9:16:40 PM | Session Note Entry | |
| | Note: Sacre, Candace | Provide responses to data requests? |
| 9:16:49 PM | Session Note Entry | |
| | Note: Sacre, Candace | If ask same questions |
| 9:16:55 PM | Session Note Entry | |
| | Note: Sacre, Candace | Questions? |
| 9:17:04 PM | Chairman Chandler - witness Vaughan | |
| | Note: Sacre, Candace | Examination. Heard conversation about Mitchell? |
| 9:17:23 PM | Session Note Entry | |
| | Note: Sacre, Candace | If Mitchell plans on operating into infinity, owned by operating companies in AEP system, available for ???, regardless of who should account for who gets benefit count towards 700 MW as derated by some future ???, some value in AEP ??? |
| 9:19:16 PM | Session Note Entry | |
| | Note: Sacre, Candace | Prorated from ??? |
| 9:19:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | Insofar as modeling assumed full capacity purchase, outerbound of that cost, probably buy 5/12ths of that? |
| 9:20:17 PM | Session Note Entry | |
| | Note: Sacre, Candace | ??? |

| | | |
|---|---|---|
| 9:20:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | Bilateral agreements exclusively for capacity? |
| 9:20:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Company entered into any firm energy contracts? |
| 9:21:06 PM | Session Note Entry | |
| | Note: Sacre, Candace | PCA referred to as bridge ??? agreement? |
| 9:21:21 PM | Session Note Entry | |
| | Note: Sacre, Candace | Idea was a bridge, get you from one place to another? |
| 9:21:34 PM | Session Note Entry | |
| | Note: Sacre, Candace | Not purchased bilateral transactions that included ???? |
| 9:22:16 PM | Session Note Entry | |
| | Note: Sacre, Candace | Portfolio resource? |
| 9:22:26 PM | Session Note Entry | |
| | Note: Sacre, Candace | If not call it a rubric, what call scoring ??? |
| 9:22:58 PM | Session Note Entry | |
| | Note: Sacre, Candace | Based on time with companies, what experience with RFPs? |
| 9:23:38 PM | Session Note Entry | |
| | Note: Sacre, Candace | Involved in creation of rubrics before? |
| 9:24:11 PM | Session Note Entry | |
| | Note: Sacre, Candace | Your time at AEP and hear questions earlier about executive compensation ??? |
| 9:24:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Had first rate account of ??? |
| 9:25:52 PM | Session Note Entry | |
| | Note: Sacre, Candace | Been since March of this year amended? |
| 9:26:04 PM | Session Note Entry | |
| | Note: Sacre, Candace | If for instance getting information from April 2024 shareholders ??? |
| 9:26:30 PM | Session Note Entry | |
| | Note: Sacre, Candace | Mr. Gish, redirect? |
| 9:26:39 PM | Session Note Entry | |
| | Note: Sacre, Candace | Redirect Examination. ???? proposed at FERC ??? |
| 9:27:22 PM | Session Note Entry | |
| | Note: Sacre, Candace | Anything else? |
| 9:27:31 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Data requests issued by June 15. |
| 9:28:16 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Fourteen days for responses? |
| 9:29:01 PM | Chairman Chandler | |
| | Note: Sacre, Candace | Will have a post-hearing procedural schedule. |
| 9:29:28 PM | Session Note Entry | |
| | Note: Sacre, Candace | Two outstanding |
| 9:29:41 PM | Session Note Entry | |
| | Note: Sacre, Candace | Hearing adjourned. |
| 9:29:52 PM | Session Ended | |

# Exhibit List Report

**2023-00092 12Jun2024**

**Kentucky Power Company (Kentucky Power)**

| Name: | Description: |
|---|---|
| ATTY GENERAL HEARING EXHIBIT 1 | PJM DECEMBER 2023 EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) REPORT January 1th, 2024 |
| ATTY GENERAL HEARING EXHIBIT 2 | PJM PRELIMINARY ELCC CLASS RATINGS FOR PERIOD 2026/27 THROUGH 2034/35 |
| JOINT INTERVENORS HEARING EXHIBIT 1 | BEST SYSTEM EMISSION REDUCTION BSER AT-A-GLANCE FACT SHEET |
| JOINT INTERVENORS HEARING EXHIBIT 2 | AEP COMMENTS |
| JOINT INTERVENORS HEARING EXHIBIT 3 | GROUP 2 ALLOWANCE ALLOCATION |
| JOINT INTERVENORS HEARING EXHIBIT 4 | GROUP 3 ALLOWANCE ALLOCATION |
| JOINT INTERVENORS HEARING EXHIBIT 5 | CO2 EMISSIONS |
| JOINT INTERVENORS HEARING EXHIBIT 6 | CROSS-STATE OZONE ALLOWANCE |
| KIUC HEARING EXHIBIT 1 | 7.5.1 DETAILS OF PREFERRED PLAN. KENTUCKY POWER 2022 INTEGRATED RESOURCE PLAN VOLUME A - PUBLIC VERSION PAGE 173 OF 1182 |
| KIUC HEARING EXHIBIT 2 | 7.5.4 RATE IMPACTS OF OF THE PREFERRED PLAN. KENTUCKY POWER 2022 INTEGRATED RESOURCE PLAN VOLUME A - PUBLIC VERSION PAGE 180 OF 1182 |
| KIUC HEARING EXHIBIT 3 | KENTUCKY POWER COMPANY KPSC CASE NO. 2023-00092 AG-KIUC'S FIRST SET OF DATA REQUESTS DATED MAY 22, 2023 AG_KIUC 1_43 WITNESS: THOMAS HARATYM |
| KIUC HEARING EXHIBIT 4 | KPSC CASE NO. 2023-00092 COMMISSION STAFF'S FIRST SET OF DATA REQUESTS DATED MAY 22, 2023 ITEM NO. 8 ATTACHMENT 9 PAGE 1 OF 8 |
| KIUC HEARING EXHIBIT 5 | KENTUCKY POWER COMPANY KPSC CASE NO. 2023-00092 STAFF'S FIRST SET OF DATA REQUESTS DATED MAY 22, 2023 KPSC 1_38 WITNESS: THOMAS HARATYM (CHARLES RIVER AND ASSOCIATES) |

# December 2023 Effective Load Carrying Capability (ELCC) Report

January 1th, 2024

For Public Use

ATTORNEY GENERAL
HEARING EXHIBIT 1

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## Contents

## Introduction

PJM uses the Effective Load Carrying Capability (ELCC) methodology to calculate the ELCC Class Ratings for ELCC Classes and Accredited Unforced Capacity (AUCAP) values for ELCC Resources. This December 2023 ELCC Report provides background information on the calculation of the above parameters as well as the resulting values for the parameters. For the December 2023 ELCC Report, ELCC Class Ratings are calculated for each delivery year in the period 2024/2025 – 2033/2034 but only the 2024/2025 values are final (the results for the rest of the delivery years are preliminary). The ELCC methodology employed to perform the calculations is documented in PJM Manual 20 (Section 5) and PJM Manual 21A.

Note that throughout this document all references to a year are effectively references to a delivery year. For simplicity, the delivery years are labeled using the year corresponding to the summer season. Therefore, for example, delivery year 2024 refers to delivery year 2024/2025.

## Assumptions

Table 1 provides a list of the assumptions used in the December 2023 ELCC calculations.

*Table 1: December 2023 ELCC Study Assumptions*

| Parameter | December 2023 ELCC Study | Basis for Assumption |
|---|---|---|
| **ELCC Classes (ELCC Classes for which ELCC Class Ratings are calculated)** | Onshore Wind, Offshore Wind, Solar Fixed Panel, Solar Tracking Panel, 4-hr Energy Storage, 6-hr Energy Storage, 8-hr Energy Storage, 10-hr Energy Storage, Solar Hybrid Open Loop, Solar Hybrid Closed Loop, Intermittent Hydropower, Landfill Gas Intermittent, Hydro with Non-Pumped Storage | ELCC Classes with members that are expected to offer or provide capacity in the target year are determined based on a vendor's forecast and PJM Interconnection Queue information |
| **ELCC Resources Deployment Forecast** | December 2023 vintage | Most recently developed deployment forecast |
| **Historical Weather Delivery Years** | 2012 – 2022 | 2012 was the first delivery year with a non-negligible amount of ELCC Resources; 2022 was the most recent delivery year for which ELCC resource performance and load data were available |

| | | |
|---|---|---|
| **Weight for each Historical Weather Year (for the calculation of LOLE and ultimately ELCC Class Ratings)** | 2012: 0.159<br>2013: 0.078<br>2014: 0.071<br>2015: 0.159<br>2016: 0.078<br>2017: 0.071<br>2018: 0.078<br>2019: 0.077<br>2020: 0.077<br>2021: 0.077<br>2022: 0.078 | Analysis based on actual weather in each of the 11 delivery years and the weather scenarios considered in the 2024 PJM Load Forecast |
| **Hourly Load Scenarios** | 11,000 (1,000 for each of the 11 Historical Weather Years) | Generate wide range of load scenarios based on the 12 monthly peaks corresponding to each weather scenario in the 2024 PJM Load Forecast |
| **"Behind-the-meter" Solar Forecast** | Consistent with 2024 PJM Load Forecast | Consistent with Reliability Requirement calculation |
| **Thermal Unlimited Resources (Unit List)** | Consistent with 2023 Reserve Requirement Study (RRS) | Consistent with Reliability Requirement calculation |
| **Thermal Unlimited Resources (Performance: Forced Outages)** | Modeled via Monte Carlo using forced outage metrics consistent with 2023 Reserve Requirement Study (RRS). Modeling of winter peak week generator performance and summer ambient derates is consistent with 2023 RRS. | Consistent with Reliability Requirement calculation |

| | | |
|---|---|---|
| **Thermal Unlimited Resources (Performance: Planned and Maintenance Outages)** | Modeled via deterministic scheduling algorithm using metrics consistent with 2023 Reserve Requirement Study (RRS). Winter peak week modeling consistent with 2023 RRS. | Consistent with Reliability Requirement calculation |
| **Variable Resources** | Output shapes developed for each Historical Weather Year based on actual and backcasted output of existing and planned units. The same output shapes are used for the calculations in each year of the 2024 – 2033 period. | Consistent with Historical Weather Years as well as collection of existing and planned units |
| **Solar Hybrid Resources (Open Loop and Closed Loop)** | Configuration of these resources in ELCC Model:<br><br>Storage component: 4-hr duration, 25% of solar hybrid Maximum Facility Output<br><br>Solar component: tracking panel, 100% of solar hybrid Maximum Facility Output. | ELCC data submission process and PJM Interconnection Queue |
| **Primary Reserves** | 2,450 MW | Consistent with PJM System Operations |
| **Demand Resources** | Consistent with 2024 PJM Load Forecast | Consistent with other planning models |
| **Capping of Hourly Output** | In all years except for 2024 the hourly output of ELCC Resources is capped in accordance with the CIRs for ELCC FERC filing documented in PJM M20 and M21A | Consistent with CIRs for ELCC FERC filing ER23-1067-000 |

## 2024 Results: ELCC Class Ratings and Accredited UCAP values

The ELCC Portfolio Rating i.e., the AUCAP value of the entire set of ELCC Resources as a share of the total nameplate, for 2024 is 51%.

The allocation of the Portfolio ELCC to each of the ELCC Classes for each of the delivery years is performed in accordance with the procedure described in PJM Manual 20, Section 5.6. The resulting ELCC Class Ratings are shown in Table 2.

*Table 2: ELCC Class Ratings for 2024/2025*

| ELCC Class | 2024/2025 |
|---|---|
| Onshore Wind | 21% |
| Offshore Wind | 47% |
| Solar Fixed Panel | 33% |
| Solar Tracking Panel | 50% |
| 4-hr Storage | 92% |
| 6-hr Storage | 100% |
| 8-hr Storage | 100% |
| 10-hr Storage | 100% |
| Solar Hybrid Open Loop - Storage Component | 75% |
| Solar Hybrid Closed Loop - Storage Component | 68% |
| Hydro Intermittent | 36% |
| Landfill Gas Intermittent | 61% |
| Hydro with Non-Pumped Storage* | 95% |

* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

To illustrate the differences in the December 2023 values relative to the December 2022 values, Table 3 shows a comparison between the 2024/2025 ELCC Class Ratings from the December 2023 report and those from the December 2022 report[1]. The major differences in 2024 ELCC Class Ratings are the decreases for the Solar Fixed, Solar Tracking, and Storage Component in Solar Hybrid classes and the increases for 4-hr Storage and wind classes. In the case of the Solar classes decreases, the changes are driven by more winter risk in the December 2023 study compared to the December 2022 study (in this year's study about 34% of the LOLE risk in 2024 is in the winter while in last year's study it was less than 1%); in the case of the decreases for the Storage Component in Solar Hybrid classes, the change is driven by the hybrid being output-constrained. In other words, the storage component cannot output enough megawatts because the solar component is using the majority of the hybrid's maximum facility output (please refer to Solar Hybrid Resources in the assumptions table. Also, in the case of the Closed Loop hybrid, the Class Rating is even lower for the Storage Component due to low solar output in the winter, which prevents the storage component of the resource from charging. In the case of the increases, the 4-hr Storage rating benefits from shorter duration events, even those in the winter, while the increases for the wind classes are driven by more winter risk.

*Table 3: Comparison of 2024 ELCC Class Ratings between December 2023 and December 2022 Reports*

| ELCC Class | ELCC Class Rating for 2024/2025 (December 2023) | ELCC Class Rating for 2024/2025 (December 2022) | Difference (in percentage points) |
|---|---|---|---|
| Onshore Wind | 21% | 18% | +3 |
| Offshore Wind | 47% | 43% | +4 |
| Solar Fixed Panel | 33% | 45% | -12 |
| Solar Tracking Panel | 50% | 56% | -6 |
| 4-hr Storage | 92% | 82% | +10 |
| 6-hr Storage | 100% | 98% | +2 |
| 8-hr Storage | 100% | 100% | 0 |
| 10-hr Storage | 100% | 100% | 0 |
| Solar Hybrid Open Loop - Storage Component | 75% | 85% | -10 |
| Solar Hybrid Closed Loop - Storage Component | 68% | 85% | -17 |
| Hydro Intermittent | 36% | 40% | -4 |
| Landfill Gas Intermittent | 61% | 63% | -2 |

[1] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx

| | | | |
|---|---|---|---|
| Hydro with Non-Pumped Storage* | 95% | 95% | 0 |

* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

The Accredited UCAP (AUCAP) values for existing and planned resources for use in the 2024 3IA are calculated as the product of the respective ELCC Class Ratings from this report, the Performance Adjustment values calculated concurrent with this report and the Effective Nameplate values. AUCAP values and Performance Adjustment values cannot be made public, but are available in Capacity Exchange on a unit-specific basis to the applicable PJM Members.

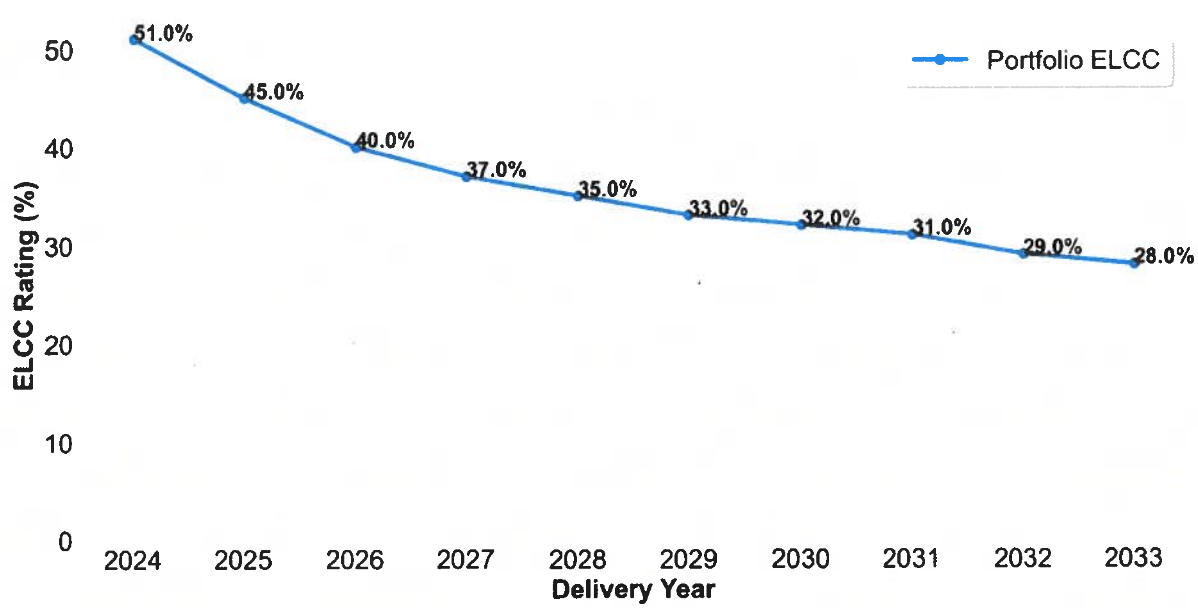
## 2024 - 2033 Results: ELCC Class Ratings

ELCC Class Ratings are provided for every delivery year in the period 2024 – 2033. Note that ELCC Class Ratings for delivery years other than 2024 are preliminary (for 2024, they are final).

### *Portfolio of ELCC Resources: 2024 – 2033 ELCC Rating*

Figure 1 shows the ELCC Rating of the Portfolio of ELCC Resources (as a share of total nameplate of ELCC Resources) for the period 2024 – 2033. The rating exhibits a marked downward trend as the overall penetration of ELCC Resources increases. Any potential complementarity between some of the ELCC Classes is not sufficient to reverse the downward trend in the ELCC Rating of the Portfolio of ELCC Resources.

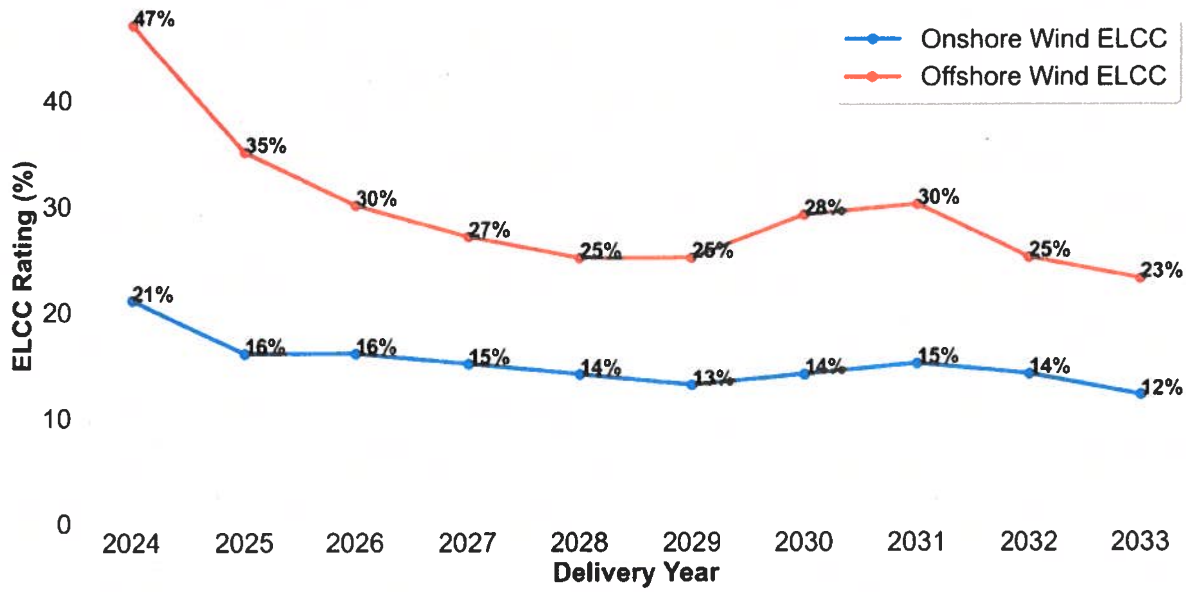
*Figure 1: 2024 - 2033 ELCC Portfolio Rating*



## *Onshore Wind & Offshore Wind: 2024 – 2033 ELCC Class Ratings*

Figure 2 shows the 2024 – 2033 ELCC Class Ratings for Onshore Wind and Offshore Wind. The ratings for both classes exhibit a sharp decrease at the beginning of the period due to the capping of hourly output at assessed deliverability in 2025. After 2025, the ELCC Class Ratings are rather stable.

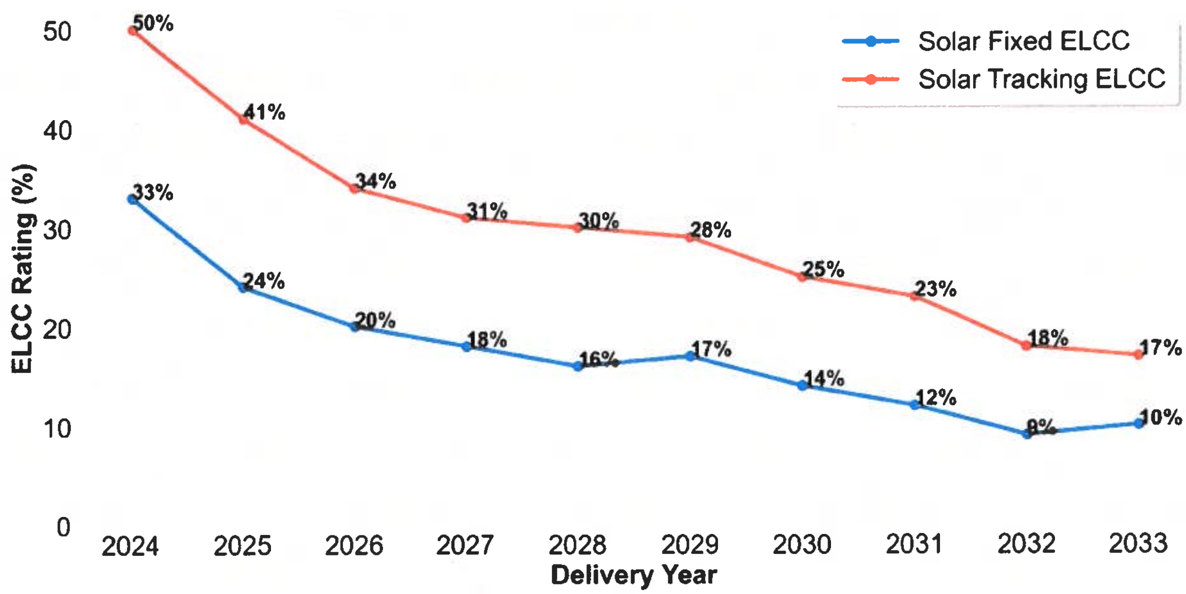
*Figure 2: 2024 – 2033 ELCC Class Ratings for Onshore Wind & Offshore Wind*



## *Solar Fixed Panel & Solar Tracking Panel: 2024 – 2033 ELCC Class Ratings*

Figure 3 shows the 2024 – 2033 ELCC Class Ratings for Solar Fixed Panel and Solar Tracking Panel. The ratings for both classes exhibit a steep decline as the forecasted penetration level of each class increases.

*Figure 3: 2024 - 2033 ELCC Class Ratings for Solar Fixed Panel & Solar Tracking Panel*

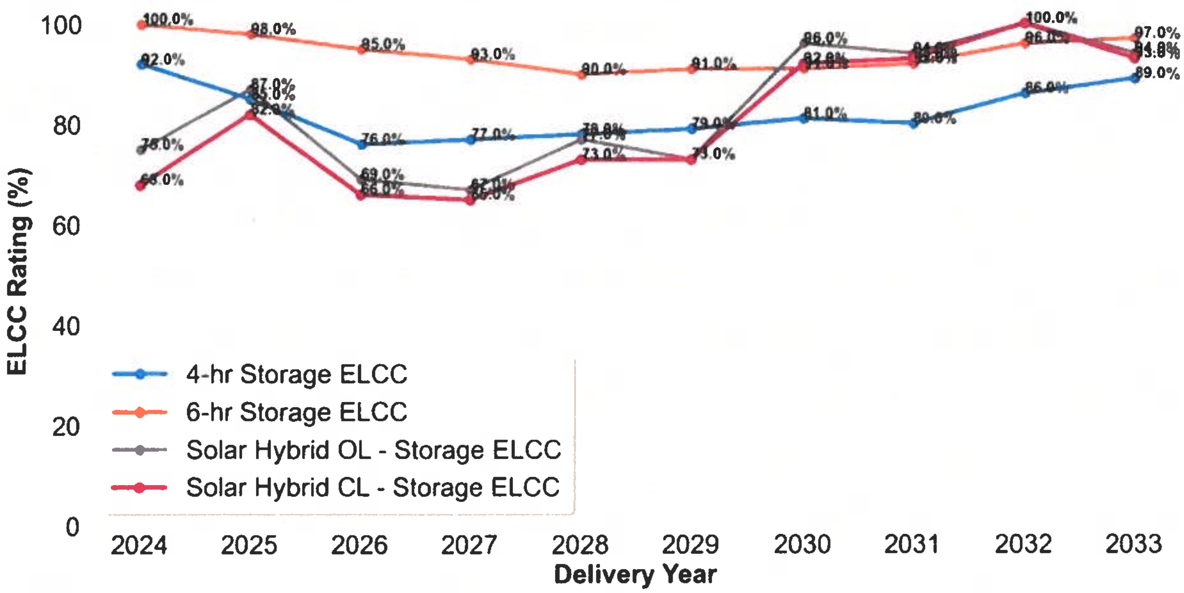



## *4-hr Storage, 6-hr Storage, Solar Hybrid Open Loop (OL) - Storage Component, Solar Hybrid Closed Loop (CL) - Storage Component: 2024 – 2033 ELCC Class Ratings*

Figure 4 shows the 2024 – 2033 ELCC Class Ratings for 4-hr Storage, 6-hr Storage and the Storage Component of Solar Hybrids (for both, open and closed loop). The 6-hr Storage rating exhibits a mild decline until 2028 and then picks up again in 2031.

A similar pattern of decline and increase in class rating can be observed for 4-hr Storage, though the decline is more pronounced and the rating values are lower than for 6-hr Storage. The ratings for the storage component of open-loop and closed-loop solar hybrids are higher for the open-loop resource due to the ability of these resources to charge from the grid while the storage component in the closed-loop solar hybrid cannot fully charge from the solar component in the winter period (and, as noted earlier, a significant portion of the LOLE risk is in the winter).

*Figure 4: 2024 – 2033 ELCC Class Ratings for 4-hr Storage, 6-hr Storage, Solar Hybrid Open Loop (OL) - Storage Component, Solar Hybrid Closed Loop (CL) - Storage Component*

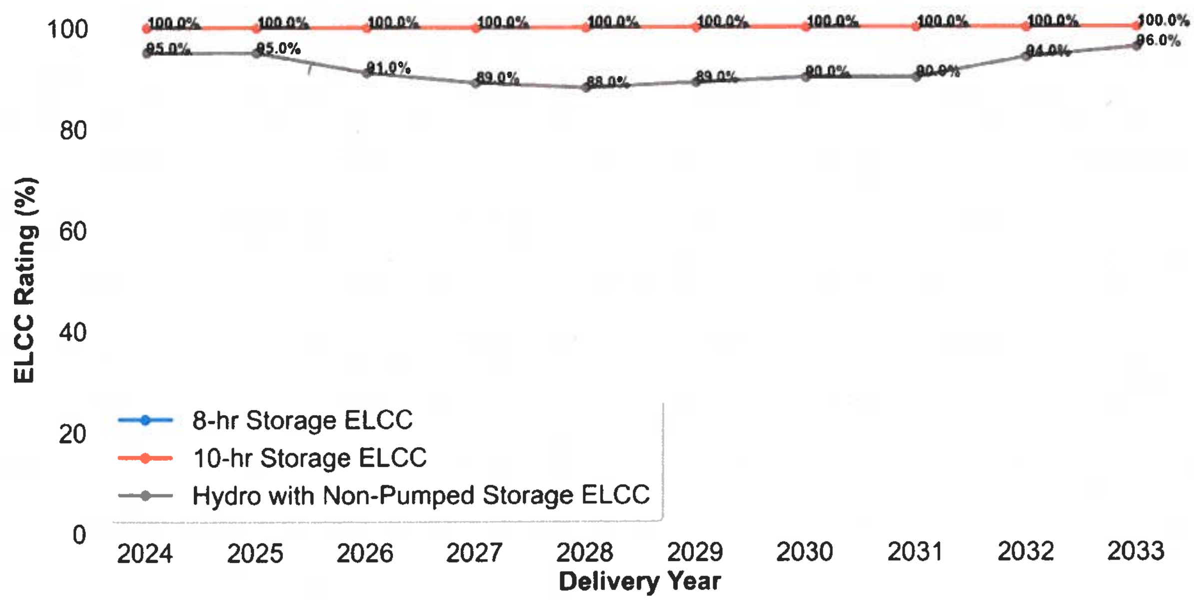



## *8-hr Storage, 10-hr Storage, Hydro with Non-Pumped Storage: 2024 – 2033 ELCC Class Ratings*

Figure 5 shows the 2024 – 2033 ELCC Class Ratings for 8-hr Storage, 10-hr Storage and Hydro with Non-Pumped Storage. The ratings for 8-hr Storage and 10-hr Storage remain constant at 100% for the entire period.

Figure 5 also shows an aggregate rating for the Hydro with Non-Pumped Storage class, notwithstanding the fact that PJM performs an ELCC analysis for each individual unit in this class. The trend for the aggregate rating of this class follows the same pattern as that observed for the classes in Figure 4.

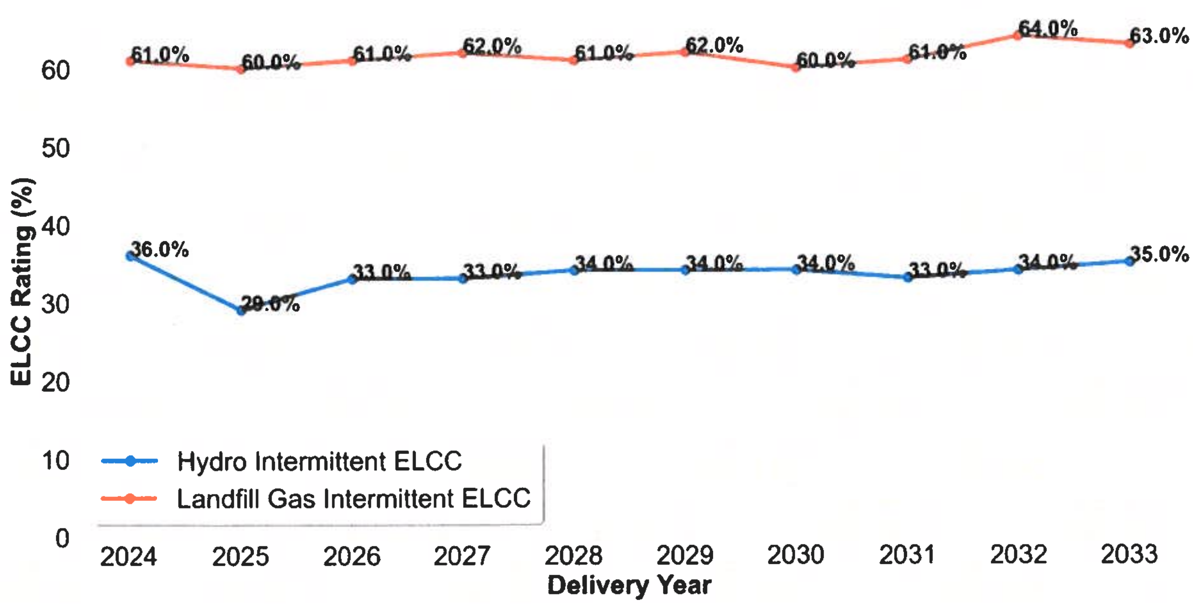
*Figure 5: 2024 – 2033 ELCC Class Ratings for 8-hr Storage, 10-hr Storage, Hydro with Non-Pumped Storage*




### Hydro Intermittent & Landfill Gas Intermittent: 2024 – 2033 ELCC Class Ratings

Figure 6 shows the 2024 – 2033 ELCC Class Ratings for Hydro Intermittent and Landfill Gas Intermittent resources. In general, the ratings for both classes exhibit a slight upward trend.

*Figure 6: 2024 – 2033 ELCC Class Ratings for Hydro Intermittent & Landfill Gas Intermittent*



## Portfolio and All ELCC Classes: 2024 – 2033 ELCC Class Ratings

Table 4 summarizes all the information provided in the above Figures.

*Table 4: 2024 - 2033 ELCC Class Ratings and ELCC Portfolio Rating*

| ELCC Class | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Onshore Wind** | 21% | 16% | 16% | 15% | 14% | 13% | 14% | 15% | 14% | 12% |
| **Offshore Wind** | 47% | 35% | 30% | 27% | 25% | 25% | 29% | 30% | 25% | 23% |
| **Solar Fixed** | 33% | 24% | 20% | 18% | 16% | 17% | 14% | 12% | 9% | 10% |
| **Solar Tracking** | 50% | 41% | 34% | 31% | 30% | 29% | 25% | 23% | 18% | 17% |
| **4-hr Storage** | 92% | 85% | 76% | 77% | 78% | 79% | 81% | 80% | 86% | 89% |
| **6-hr Storage** | 100% | 98% | 95% | 93% | 90% | 91% | 91% | 92% | 96% | 97% |
| **8-hr Storage** | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **10-hr Storage** | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Solar Hybrid Open Loop - Storage Component** | 75% | 87% | 69% | 67% | 77% | 73% | 96% | 94% | 100% | 94% |
| **Solar Hybrid Closed Loop - Storage Component** | 68% | 82% | 66% | 65% | 73% | 73% | 92% | 93% | 100% | 93% |
| **Hydro Intermittent** | 36% | 29% | 33% | 33% | 34% | 34% | 34% | 33% | 34% | 35% |
| **Landfill Gas** | 61% | 60% | 61% | 62% | 61% | 62% | 60% | 61% | 64% | 63% |
| **Hydro Non-Pumped Storage** | 95% | 95% | 91% | 89% | 88% | 89% | 90% | 90% | 94% | 96% |
| **Portfolio** | 51% | 45% | 40% | 37% | 35% | 33% | 32% | 31% | 29% | 28% |

* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

## Description of Posted Files

PJM has posted the following files as background information for the calculation of 2024 ELCC Class Rating and Accredited UCAP values. Note that the data contained in these files is *simulated data* whose only purpose is to calculate ELCC Class Rating and Accredited UCAP values. **The simulated data is not intended to be a prediction of how the system will perform in future years**.

*Replications_LOLE_2024.zip*: this zip file contains a collection of several CSV files, one for each of the scenarios with LOLE in each of the 10 historical weather years (scenarios without LOLE are not posted). The files correspond to the ELCC run that result in the ELCC Class Rating values shown in Table 2 (for 2024). The LOLE of the case is 0.1 days per year. The columns in each file are as follows:

- Unnamed Column: 0-8760(8784). Hour number of the delivery year. The delivery years begin on June 1st.
- Load: In MW. Load at the given hour.
- ThCap: In MW. Unlimited Thermal Capacity available at the given hour (after Forced, Planned and Maintenance outages)
- ThOutageRate: As fraction between 0 and 1. Unlimited Thermal Capacity outage rate at given hour (includes Forced, Planned and Maintenance outages)
- OnshoreWind: In MW. Total onshore wind output at given hour.
- OffshoreWind: In MW. Total offshore wind output at given hour.
- SolarFixed: In MW. Total solar fixed panel output at given hour.
- SolarTracking: In MW. Total solar tracking panel output at given hour.
- HydroInt: In MW. Total hydro intermittent output at given hour.
- LandfillInt: In MW. Total landfill gas intermittent output at given hour.
- 6hrStorage: In MW. Total 6-hr Storage dispatched at given hour.
- HydroNPS: In MW. Total Hydro with Non-Pumped Storage dispatched at given hour.
- OL_Hybrid: In MW. Total Solar Hybrid Open Loop dispatched at given hour (includes solar and storage output)
- CL_Hybrid: In MW. Total Solar Hybrid Closed Loop dispatched at given hour (includes solar and storage output)
- 4hrStorage: In MW. Total 4-hr Storage dispatched at given hour.
- DRDispatched: In MW. Total amount of DR dispatched at given hour.
- Ambient: In MW. Hourly ambient derates during peak weeks of summer. A total of 2,500 MW are modeled as not available to be consistent with Reserve Requirement Study (these derates are not included in ThCap and ThOutageRate columns).

- AddPlannedOutages: In MW. Additional planned outages modeled during winter peak week to be consistent with Reserve Requirement Study (these additional planned outages are not included in ThCap and ThOutageRate columns).
- SolarHyOL: In MW. Total solar component output in Solar Hybrid Open Loop.
- SolarHyCL: In MW. Total solar component output in Solar Hybrid Closed Loop.
- MarginBeforeDR: in MW. Margin before dispatching DR calculated as total available resources minus load.
- MarginAfterDR: in MW. Margin after dispatching DR. This is the margin value used to determine if there is LOLE or not. LOLE is declared if MarginAfterDR is less than -0.1 MW (the model has a tolerance of 0.1 MW).
- LOLE: 0 or 1. If 1, there is loss of load in the given hour; if 0, there is no loss of load.
- Day: 1-365(366). Day number of the year
- Hour Beginning: 0-23. Eastern Prevailing Time Hour beginning.

*Load_Scenarios_2024.zip*: this zip file contains 11 CSV files, one for each of the 11 historical weather years. Each CSV file has either 8,760 or 8,784 rows (one for each hour of the year) and 1,000 columns (one for each of the 1,000 replications; the columns are named from 0 to 999). All values in the files are in MW and represent hourly loads in each scenario.

*Available_Unlimited_Thermal_Scenarios_2024.zip*: this zip file contains 11 CSV files, one for each of the 11 historical weather years. Each CSV file has either 8,760 or 8,784 rows (one for each hour of the year) and 1,000 columns (one for each of the 1,000 replications; the columns are named from 0 to 999). All values in the files are in MW and represent available hourly unlimited thermal capacity available in each scenario. Note that ambient derates and additional planned outages (columns Ambient and AddPlannedOutages in the Replications files) during winter peak weeks are not accounted for in these files.

*200_CPX2_2024.xlsx*: this file contains the hours included in the 200 CPX2 metric used to calculate the Performance Adjustment for Variable Resources and Variable Resources components in Combination Resources. The file has two sheets: the sheet "Gross" has the top 200 gross load hours; the sheet "Net" has the top 200 net load hours where net load is defined as gross load minus the potential output of Variable Resources. Note that the hourly load values in this file should be interpreted as the potential hourly load values (gross and net) in 2024 if the same pattern of historical weather that occurred on the past hours listed in the file were to repeat themselves in that year.

ATTORNEY GENERAL
HEARING EXHIBIT 2

# Preliminary ELCC Class Ratings for Period 2026/27 through 2034/35

Patricio Rocha Garrido
Resource Adequacy Planning
Planning Committee
June 4, 2024

## Background

- As part of FERC-approved Docket No. ER24-99, PJM shall post preliminary ELCC Class Rating values for nine subsequent Delivery Years at least once per year
- Such preliminary ELCC Class Ratings are posted at:

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

- Assumed Portfolio for each future Delivery Year
  - Assumed Portfolio for 2025/26 was used as the starting point. Additions and deactivations from a vendor's forecast were then used to derive future deployment levels.
  - The Assumed Portfolio for each future Delivery Year is available upon request. Please send your request to ELCC@pjm.com
- Some trends in the Assumed Portfolio for the study time period:
  - Sustained addition of wind classes, solar classes, 4-hr storage class and solar-storage hybrid classes
  - Some coal units are assumed to deactivate. Negligible additions and deactivations in other Unlimited Resource classes

# Assumptions

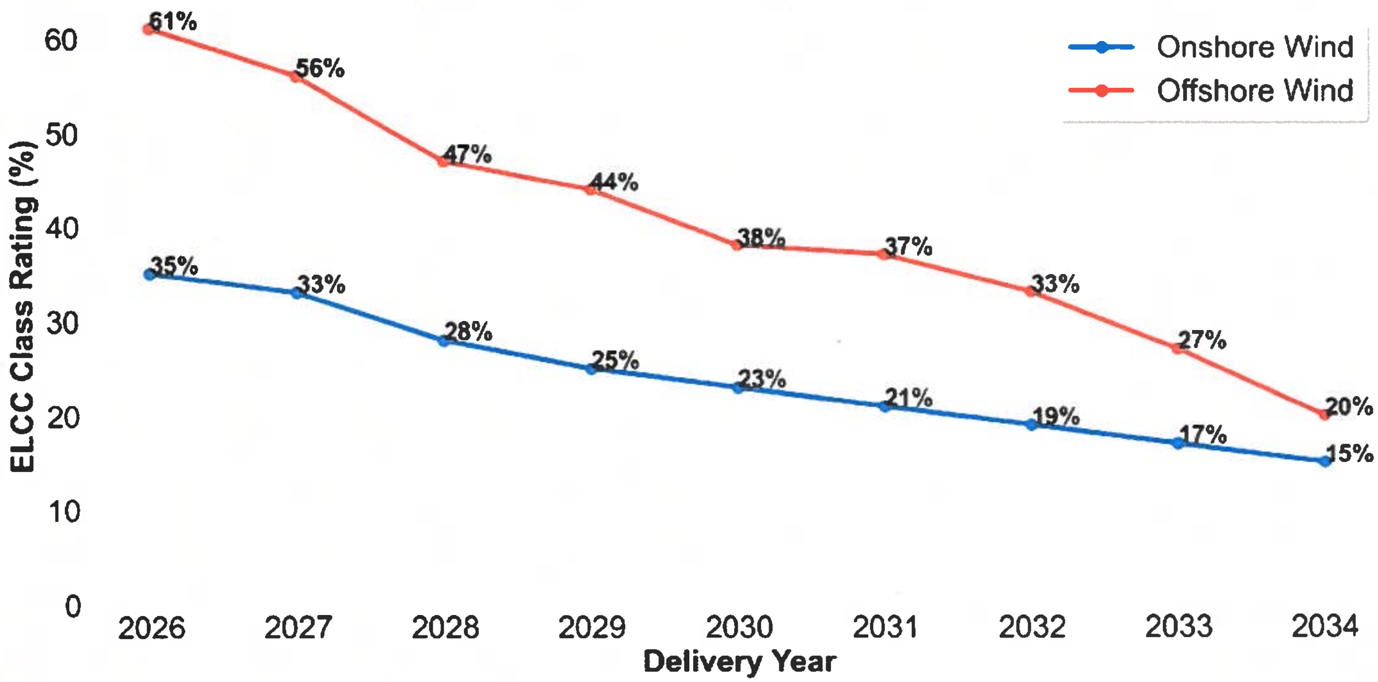
- Hourly outage/derate/output data for Unlimited and Variable Resources is representative of the 2025/26 resource mix, scaled up or down by each ELCC Class's future deployment levels included in the Assumed Portfolio for each future Delivery Year
  - This implies that PJM is not modeling the specific location or characteristics of the expected additions and deactivations
- Hourly load scenarios were derived for each future Delivery Year based on the 2024 PJM Load Forecast model.

# Preliminary ELCC Class Ratings – DY 26/27 through DY 34/35

| ELCC Class | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 | 2032/33 | 2033/34 | 2034/35 |
|---|---|---|---|---|---|---|---|---|---|
| Onshore Wind | 35% | 33% | 28% | 25% | 23% | 21% | 19% | 17% | 15% |
| Offshore Wind | 61% | 56% | 47% | 44% | 38% | 37% | 33% | 27% | 20% |
| Fixed-Tilt Solar | 7% | 6% | 5% | 5% | 4% | 4% | 4% | 4% | 3% |
| Tracking Solar | 11% | 8% | 7% | 7% | 6% | 5% | 5% | 5% | 4% |
| Landfill Intermittent | 54% | 55% | 55% | 56% | 56% | 56% | 56% | 56% | 54% |
| Hydro Intermittent | 38% | 40% | 37% | 37% | 37% | 37% | 39% | 38% | 38% |
| 4-hr Storage | 56% | 52% | 55% | 51% | 49% | 42% | 42% | 40% | 38% |
| 6-hr Storage | 64% | 61% | 65% | 61% | 61% | 54% | 54% | 53% | 52% |
| 8-hr Storage | 67% | 64% | 67% | 64% | 65% | 60% | 60% | 60% | 60% |
| 10-hr Storage | 76% | 73% | 75% | 72% | 73% | 68% | 69% | 70% | 70% |
| Demand Resource | 70% | 66% | 65% | 63% | 60% | 56% | 55% | 53% | 51% |
| Nuclear | 95% | 95% | 95% | 96% | 95% | 96% | 96% | 94% | 93% |
| Coal | 84% | 84% | 84% | 85% | 85% | 86% | 86% | 83% | 79% |
| Gas Combined Cycle | 79% | 80% | 81% | 83% | 83% | 85% | 85% | 84% | 82% |
| Gas Combustion Turbine | 61% | 63% | 66% | 68% | 70% | 71% | 74% | 76% | 78% |
| Gas Combustion Turbine Dual Fuel | 79% | 79% | 80% | 80% | 81% | 82% | 83% | 83% | 83% |
| Diesel Utility | 92% | 92% | 92% | 92% | 92% | 93% | 93% | 93% | 92% |
| Steam | 74% | 73% | 74% | 75% | 74% | 75% | 76% | 74% | 73% |

# Observations about Preliminary ELCC Class Ratings

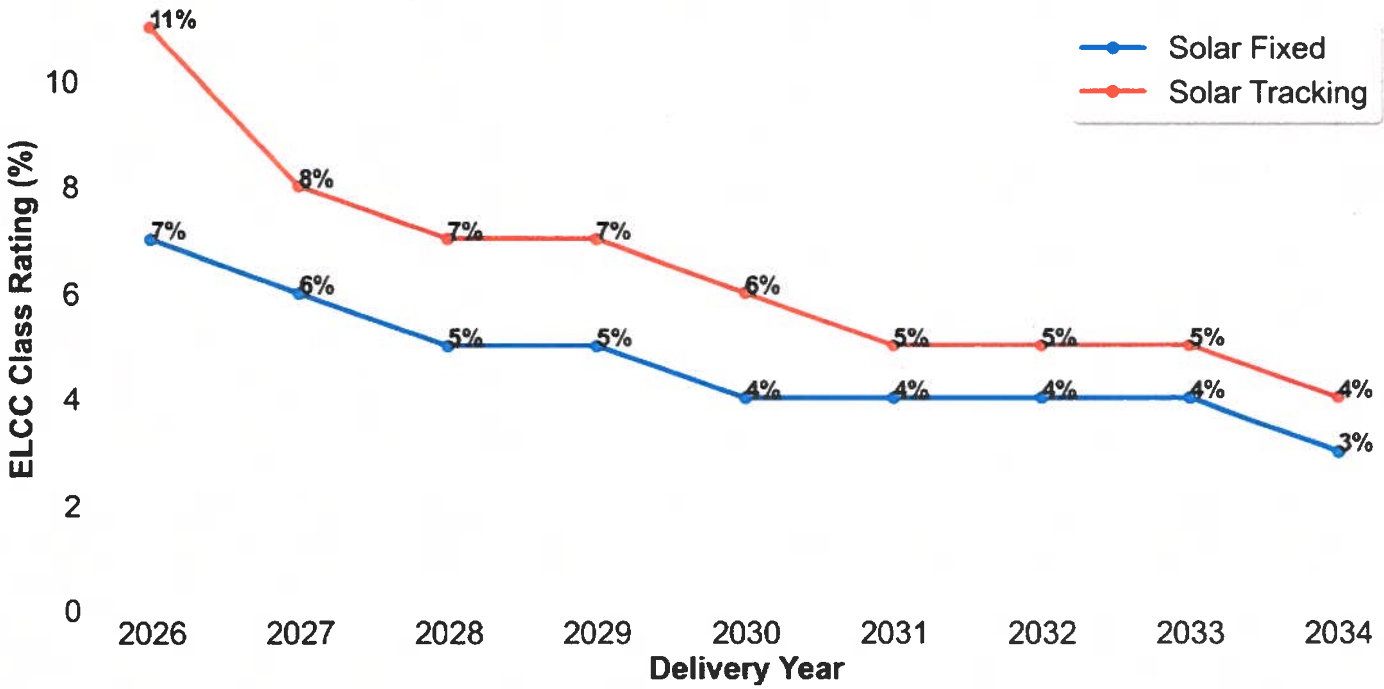
- Onshore Wind and Offshore Wind




Sustained decrease in ratings is due to risk patterns shifting to winter days where performance of wind classes is lower.

# Observations about Preliminary ELCC Class Ratings

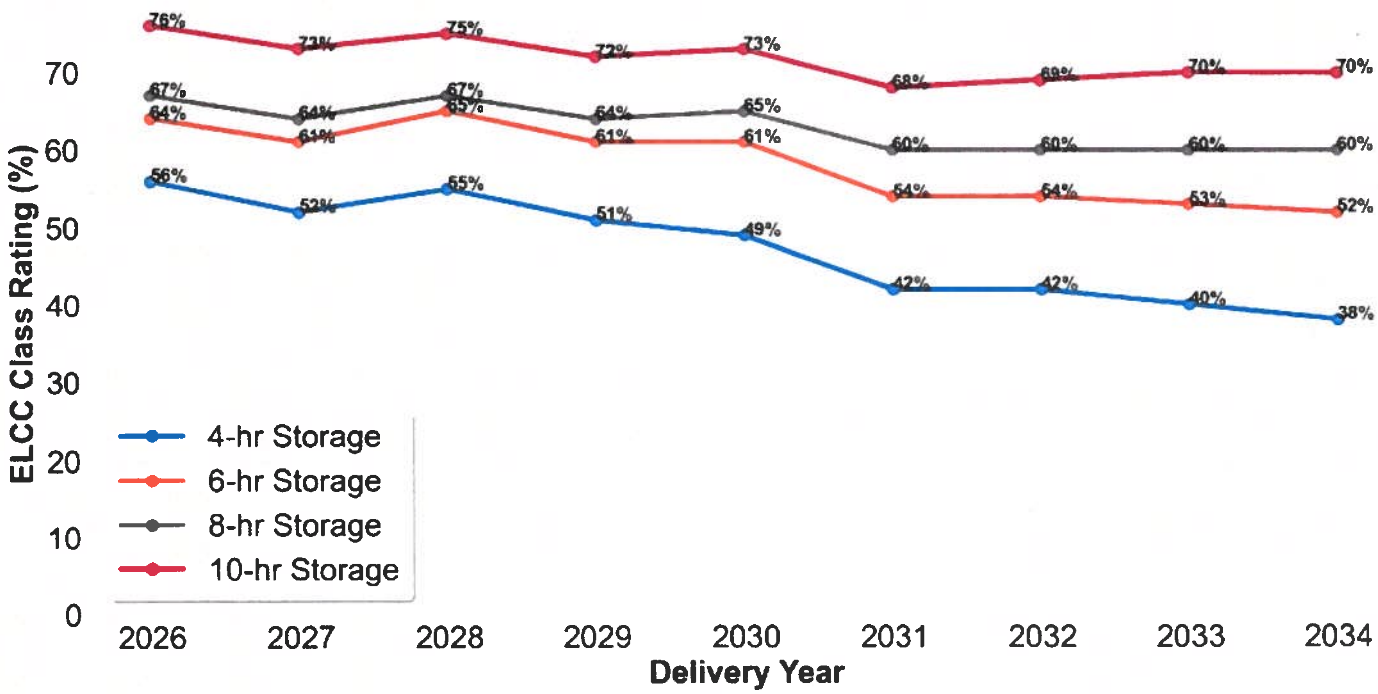
- Solar Tracking and Solar Fixed




Sustained decrease in ratings is due to the fact that the majority of risk is in winter throughout the 9-year period

# Observations about Preliminary ELCC Class Ratings

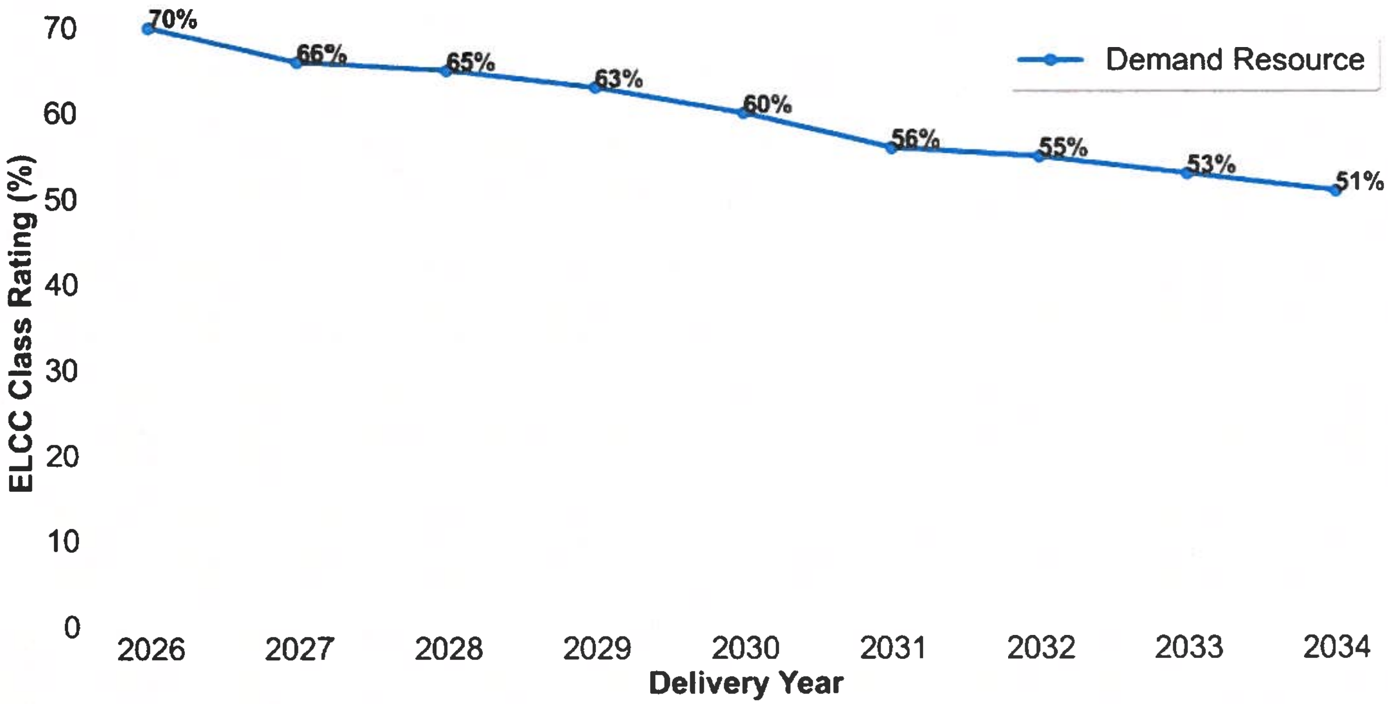
- 4-hr, 6-hr, 8-hr, 10-hr Storage




Decrease in ratings is due to the fact that the majority of risk is in winter and duration of risk events trends upward

# Observations about Preliminary ELCC Class Ratings

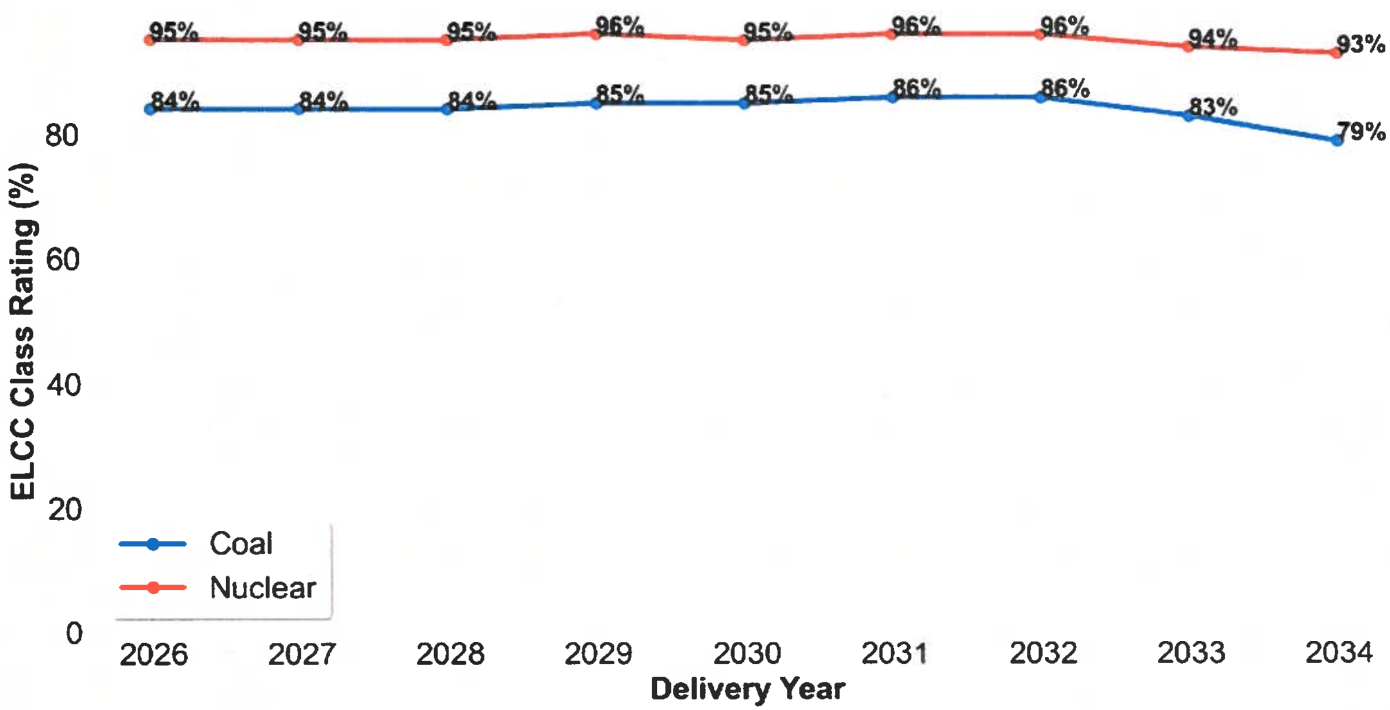
- DR




Decrease in ratings is due to the fact that risk share outside of DR's winter performance window trends upward pjm

# Observations about Preliminary ELCC Class Ratings

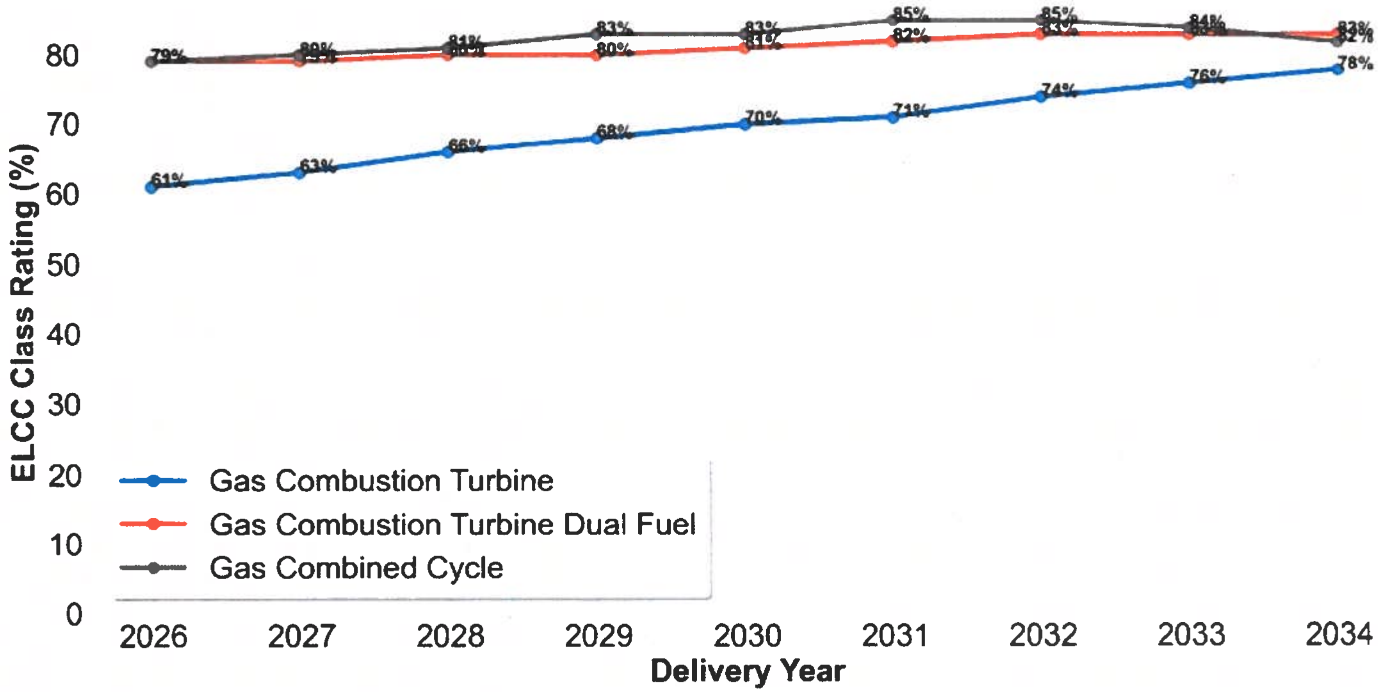
- Nuclear and Coal




Ratings are rather stable

# Observations about Preliminary ELCC Class Ratings

- Gas CT, Gas CT Dual, Gas CC




Increase in ratings is due to risk patterns shifting to winter days where performance of gas classes is better.

- Winter share of LOLE, LOLH and EUE

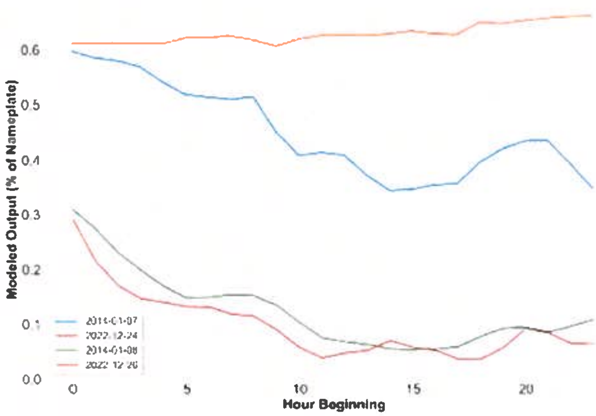
| DY | LOLE (%) | LOLH (%) | EUE (%) | LOLE (days/year) | LOLH (hours/year) | EUE (MWh/year) |
|---|---|---|---|---|---|---|
| 2025/26 | 55 | 70 | 87 | 0.1 | 0.328 | 1,463 |
| 2030/31 | 49 | 72 | 86 | 0.1 | 0.287 | 1,466 |
| 2034/35 | 42 | 66 | 82 | 0.1 | 0.321 | 2,043 |

Winter remains the riskier season from an LOLH and EUE perspective

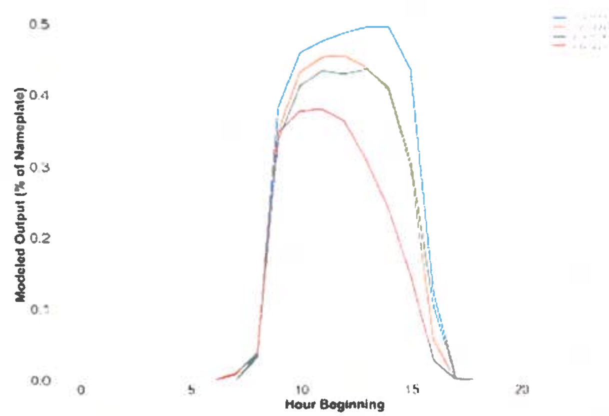
- Top Two Historical Performance Days Driving EUE Risk

| | 2025/26 | 2030/31 | 2034/35 |
|---|---|---|---|
| Top 1 | 01/07/2014 (43%) | 01/07/2014 (29%) | 01/08/2014 (22%) |
| Top 2 | 12/24/2022 (12%) | 01/08/2014 (19%) | 12/26/2022 (12%) |

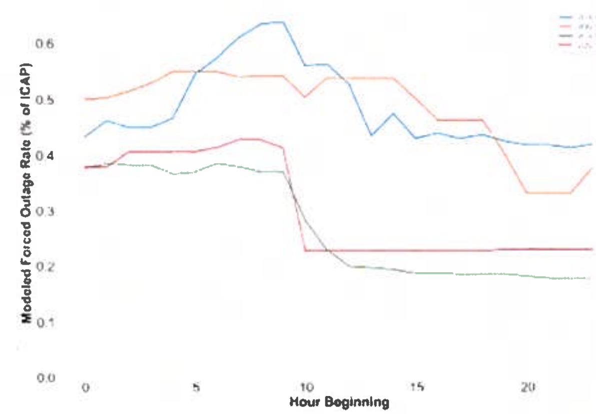
Onshore Wind Class Output




Solar Tracking Class Output




Gas CT Class Forced Outages



- Average Number of Hours in a Winter day with loss of load

| 2025/26 | 2030/31 | 2034/35 |
|---|---|---|
| 4.1 hours | 4.3 hours | 5.1 hours |

# Other Analytics

- Share of Winter EUE outside of Winter DR Performance Window

| 2025/26 | 2030/31 | 2034/35 |
| --- | --- | --- |
| 20% | 35% | 45% |

- Share of Winter LOLH outside of Winter DR Performance Window

| 2025/26 | 2030/31 | 2034/35 |
| --- | --- | --- |
| 17% | 27% | 31% |

# Contact

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Patricio Rocha Garrido
Patricio.Rocha-Garrido@pjm.com

**Chair:**
Rebecca Carroll
Rebecca.Carroll@pjm.com

**Secretary:**
Ashwini Bhat
Ashwini.Bhat@pjm.com

**Preliminary ELCC Class Ratings for Period 2026/27 through 2034/35**

Member Hotline

(610) 666 – 8980

(866) 400 – 8980

custsvc@pjm.com


PROTECT THE POWER GRID
THINK BEFORE YOU CLICK!
Be alert to malicious phishing emails.
pjm
Report suspicious email activity to PJM.
(610) 666-2244 / it_ops_ctr_shift@pjm.com

# BSER At-A-Glance

<table>
<tr><th colspan="4">FINAL CARBON POLLUTION STANDRADS FOR NEW AND EXISTING FOSSIL-FUEL FIRED ELEECTRICITY GENERATORS</th></tr>
<tr><th colspan="2">Existing 111(d) Steam Generators</th><th colspan="2">New Source and Reconstructed 111(b) Stationary Combustion Turbines</th></tr>
<tr><th>Coal-Fired Boilers</th><th>Natural Gas and Oil-Fired Boilers</th><th>Phase I<br>Date of promulgation or initial startup</th><th>Phase II<br>Beginning in Jan 1, 2032</th></tr>
<tr><td rowspan="2">Long-term subcategory: For units operating on or after January 1, 2039<br><br>BSER: CCS with 90 percent capture of $CO_2$ (88.4% reduction in emission rate lb/MWh-gross) by January 1, 2032</td><td rowspan="6">BSER: routine methods of operation and maintenance with associated degree of emission limitation:<br><br>Base load unit standard:<br>(annual capacity factors greater than 45%) 1,400 lb $CO_2$/MWh-gross<br><br>Intermediate load unit standard:<br>(annual capacity factors greater than 8% and less than or equal to 45%) 1,600 lb $CO_2$/MWh-gross.<br><br>Low load units:<br>(annual capacity factors less than 8%) a uniform fuels BSER and a presumptive input-based standard of 170 lb $CO_2$/MMBtu for oil-fired sources and a presumptive standard of 130 lb $CO_2$/MMBtu for natural gas-fired sources.<br><br>Compliance date of January 1, 2030</td><th colspan="2">Low Load Subcategory (Capacity Factor <20%)</th></tr>
<tr><td><u>BSER</u>: Use of lower emitting fuels (e.g., hydrogen, natural gas and distillate oil)<br><u>Standard</u>: less than 160 lb $CO_2$/MMBtu</td><td>EPA is not finalizing a Phase II BSER for low load units</td></tr>
<tr><td rowspan="2">Medium-term subcategory: For units operating on or after Jan. 1, 2032, and demonstrating that they plan to permanently cease operating before January 1, 2039<br><br>BSER: co-firing 40% (by heat input) natural gas with emission limitation of a 16% reduction in emission rate (lb $CO_2$/MWh-gross basis) by January 1, 2030</td><th colspan="2">Intermediate Load Subcategory (Capacity Factor 20% to 40%*)<br>*Source-specific upper bound threshold based on EGU design efficiency</th></tr>
<tr><td><u>BSER</u>: Highly efficient simple cycle technology with best operating and maintenance practices<br><u>Standard:</u> 1,170 lb $CO_2$/MWh-gross</td><td>EPA is not finalizing a Phase II BSER for intermediate load units</td></tr>
<tr><td rowspan="2">For units demonstrating that they plan to permanently cease operating before January 1, 2032<br><br>Units are exempt from the rule. Cease operations dates finalized in state plans for exemption purposes are federally enforceable.</td><th colspan="2">Base Load Subcategory (Capacity Factor >40%*)<br>*Operation above upper-bound threshold for Intermediate Subcategory</th></tr>
<tr><td><u>BSER</u>: Highly efficient combined cycle generation with the best operating and maintenance practices<br><u>Standard</u>: 800 lb $CO_2$/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more)<br><u>Standard</u>: 800 to 900 lb $CO_2$/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)</td><td><u>BSER</u>: Continued highly efficient combined cycle generation with 90% CCS by Jan 1, 2032<br><u>Standard</u>: 100 lb $CO_2$/MWh-gross<br><br>EPA's standard of performance is technology neutral, affected sources may comply with it by co-firing hydrogen.</td></tr>
<tr><td colspan="4">For new and existing units installing control technologies, a 1-year extension is available in situations in which implementation delays are due to factors beyond the EGU owner/operator's control. For existing units with cease operations dates, a 1-year extension is available in situations in which the unit is needed for reliability through a reliability assurance mechanism, provided appropriate documentation is submitted.</td></tr>
<tr><td colspan="4">Major Modifications 111(b) Coal-fired Steam Generators: Standards of performance for coal-fired units that undertake a large modification (i.e., increases hourly emission rate by more than 10%) mirror the emission guidelines for existing coal-fired steam generators.</td></tr>
</table>

Interested parties can download a copy of the final rule from EPA's website at Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants

JOINT INTERVENORS HEARING EXHIBIT 1

**American Electric Power**
1 Riverside Plaza
Columbus, OH 43215
aep.com

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2023-0072
Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

ATTN: Docket ID No. EPA-HQ-OAR-2023-0072

August 7, 2023

**RE:** *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*

Dear Sir or Madam:

American Electric Power (AEP) provides these comments on the Environmental Protection Agency's (EPA's) proposed rules for New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, published May 23, 2023, at 88 Federal Register 33240.

AEP is one of the largest electric utilities in the United States, delivering electricity to more than 5.6 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning approximately 25,000 megawatts of generating capacity in the U.S. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

If you have any questions regarding the comments, please contact Greg Wooten of my staff by email at gjwooten@aep.com.

Sincerely,

Gary O. Spitznogle
Vice President
AEP Environmental Services

Comments of American Electric Power on the Proposed
*New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*
88 Federal Register 33240 (May 23, 2023)
Docket ID No. EPA-HQ-OAR-2023-0072

Table of Contents

   F. Uncertainties regarding the applicability of RCRA regulations are a barrier to CCS development
   G. Geologic storage may be the greatest challenge to the development of CCS
   H. $CO_2$ pipeline projects present challenges to the development of CCS
   I. Enhanced oil recovery offers no guarantee of being available or willing to support CCS processes
   J. Extensive permitting introduces schedule and financial challenges to CCS projects

7. Natural gas co-firing is not the BSER for existing steam EGUs
   A. Co-firing with natural gas is not a viable option across the existing coal-fired fleet
   B. The short duration of co-firing natural gas before the unit must retire impacts the feasibility of investments being made in pipeline infrastructure

8. Hydrogen co-firing is not the BSER for natural gas combustion turbines
   A. Hydrogen co-firing at the quantities proposed have not been adequately demonstrated
   B. Challenges to achieving significant levels of hydrogen co-firing

9. Efficiency improvements are the BSER for coal and gas units

10. Case Studies for Implementing the Proposed Rule
    A. Case Study 1: CCS Questions and Considerations
    B. Case Study 2: Natural Gas Co-Firing Questions and Considerations
    C. Case Study 3: Hydrogen Co-Firing Questions and Considerations

11. The Proposed Compliance Timeline is not achievable
    A. Timing for state implementation plan development and approval is not sufficient to implement compliance strategies by 2030
    B. Timing for state implementation plan development does not allow for necessary technology and infrastructure development

12. EPA should harmonize the compliance timelines and retirement options across all pending environmental rulemakings applicable to the existing fossil-based electric generation fleet.

13. Miscellaneous Considerations
    A. Emission standards must account for source variability.
    B. Clarification of definitions in proposed regulation 40 CFR 60 Subpart UUUUb existing and modified units

Appendix A AEP Comments on Prior Section 111 Proposals

## 1. Summary of Key Comments

The key comments offered for consideration by EPA are summarized as follows:

- The remaining useful life of existing generating units should be fully considered in determining the Best System of Emission Reductions (BSER) and associated compliance timelines.
- The BSER for existing units that plan to retire by 2040 should be based only on routine operations and maintenance in order to balance grid reliability, cost, and the transformation to new generation resources.
- AEP is uniquely positioned to comment on carbon capture and storage (CCS) based on our first-hand experience with development and demonstration of the technology in an integrated configuration at a coal-combustion power plant.
- CCS is a promising technology, but significant development challenges remain that will require years to resolve. A comprehensive review of those challenges, coupled with experiences of private and public entities developing the technologies reveals that CCS has yet to be demonstrated as the BSER.
- CCS development challenges include technical, financial, regulatory, and practical concerns related to each the capture, transport, and storage aspects of the process.
- Even though much investment has gone into advancement of CCS technologies, these technologies have not yet been demonstrated to be viable for reducing CO2 emissions at fossil fueled power plants. Simply put, there exists not a single coal or gas power plant in operation today in the US with integrated CCS capturing and permanently sequestering 90% of the CO2 produced by that plant. Not one! Yet EPA is claiming that CCS applied to existing coal plants in this fashion is BSER and capable of being broadly implemented and reliably operating by 1/1/2030. The plain facts tell a different story. At the current pace of development and absent any existing commercial operations of generation-based CCS to reference, CCS will not be adequately demonstrated to be a viable control option for many years.
- Natural gas co-firing should not be the BSER because it is not cost-effective to invest in the gas pipeline infrastructure necessary to support limited operations before units must retire.
- Hydrogen co-firing has not been adequately demonstrated to be the BSER.
- Hydrogen co-firing is a promising technology, but significant development challenges remain with respect to reliable hydrogen supplies, transport and storage infrastructure, and turbine designs that can use higher volumes of hydrogen.
- The proposed compliance timeline is not feasible given the time necessary for state implementation plans to be developed and for sources to design and implement compliance strategies.

## 2. Introduction

### A. Description of AEP and Impacted Facilities

American Electric Power (AEP), on behalf of its operating companies, provides these comments on the Environmental Protection Agency's (EPA's) proposed rule for New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.[1] AEP is one of the largest electric utilities in the United States, with more than 5.6 million customers across the country and ranks among the nation's largest generators of electricity, owning approximately 25,000 megawatts of generating capacity in the U.S. AEP owns, in whole or in part, and/or operates, coal- and natural gas fired steam electric generating facilities in the states of Arkansas, Indiana, Kentucky, Louisiana, Ohio, Oklahoma, Texas, Virginia and West Virginia, which are subject to this rulemaking.

### B. AEP Efforts to Transform its Generation Fleet

AEP is in the middle of executing a deliberate strategy to transform our generating fleet to align with our corporate goal to achieve net-zero GHG emissions by 2045. Over the past decade alone, AEP has retired or sold 43 generating units amounting to nearly 14,300 MW of coal-fired generation. We plan to cease coal combustion at another five generating units, or roughly 4,100 MW, by the end of 2028. At that point, AEP will only have coal generating units operating at five remaining power plant sites (three in West Virginia and two in Arkansas). Current modeling projects that only one of these remaining coal generating units will be in service after 2040, according to the integrated resource plans filed with our state regulators. As a result, we remain on track to meet both our 2030 goal of 80% GHG reduction, against a 2005 baseline, and our 2045 goal of net-zero GHG emissions. This represents a significant transformation that has required several decades to implement due to the need to balance the development of new capacity, customer costs and reliability considerations.

A transformation strategy this extensive across an infrastructure encompassing 11 states and 3 RTOs (PJM, SPP, & ERCOT) is a monumental task of extraordinary complexity. Preliminary assessments indicate that compliance cost for an individual coal plant could easily be hundreds of million dollars for natural gas co-firing to several billion dollars for CCS. Compounding this challenge is the reality that 95% of our 5.6 million customers live in counties where the median income is consistently below the national average.

---

[1] 88 Fed Reg 33240. May 23, 2023

AEP must be able to continue to manage our transition from a fossil fuel-dependent economy to a clean energy economy thoughtfully and holistically to ensure our customers are not impacted by negative reliability or unreasonable increases to their utility bills.

It is critical to have regulatory certainty when managing our commitments, particularly when these commitments are as transformative and far reaching in their implications as described above. We believe our Net Zero goal and the means to achieve it are well aligned with the spirit of EPAs proposed 111 regulations. Included within these comments are several recommendations to improve the proposed regulations, supported by real-world experience that is backed by 117 years of utility operation and countless innovations.

### C. AEP is Uniquely Positioned to Comment on the Proposed Rulemaking

AEP has a long history of developing technologies that have set the bar for advanced coal-based generation technologies, including pioneering the use of carbon capture and storage (CCS) technology. These experiences uniquely position AEP to offer meaningful insight on the prospects for these technologies in context with the scope and timeline of the current Section 111 proposal. The comments that follow leverage these experiences to highlight the very significant technical and practical challenges that CCS, natural gas co-firing, and hydrogen technologies must overcome before these promising options can be deployed and relied upon as a viable system of emission reductions.

### D. Comments Incorporated by Reference from Other Organizations

AEP is a member of and incorporates by reference the comments filed by the Power Generators Air Coalition (PGEN), the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the Midwest Ozone Group (MOG), the National Association of Manufactures (NAM), and the Indiana Energy Association (IEA).

## 3. EPA should fully consider the remaining useful life of existing units in determining the BSER

The existing fleet of coal units in the United States is continuing the decade plus trend of retirements and conversion to lower emitting technologies. As EPA notes in the proposed rule, at least a dozen utilities have established net-zero $CO_2$ emissions goals to be achieved in the 2045 to 2050 timeframe. These utilities are on pace to achieve these goals, but the implementation process to transform the existing fleet takes time as it is essential to balance grid reliability, cost impacts to customers, technology advancements, and the time needed to build replacement generation capacity.[2]

[2] 88 Fed Reg 99. May 23, 2023. pp. 33262-3.

EPA should fully consider the remaining useful life of coal units in their development of the BSER and compliance timelines to not upend the ongoing transformation process that is delicately balancing the issues of reliability and cost. For example, it would not be prudent policy and would not result in a commensurate environmental benefit to effectively require units slated to retire before 2040 to invest billions of dollars on technologies and support infrastructure that would only be used a few years before the unit would retire. If investments in compliances strategies are made, the result would be that many existing units would simply delay their planned retirement dates to operate longer, maximize recovery of their investment costs, and minimize the potential to negatively disrupt the transformation process that is underway and to exacerbate reliability and customer impacts. Therefore, it is recommended that for existing coal units that plan to retire by 2040, the BSER should be based only on routine operations and maintenance to balance grid reliability, cost, and the transformation to new generation resources.

**4. CCS is a promising technology, but must overcome significant development challenges before it can be demonstrated to be the Best System of Emission Reductions**

Even though much investment and time has been spent advancing the state of CCS technologies, significant challenges must be addressed before CCS can become a viable option for reducing $CO_2$ emissions. A comprehensive review of those challenges, coupled with experiences of private and public entities developing the technologies reveals that CCS has yet to be demonstrated as the BSER.

**A. Before determining the BSER, EPA must fully evaluate the current state of CCS development**

While judgment is necessary in determining the BSER, EPA has the responsibility to exercise that judgment based on a fair, objective, and holistic consideration of facts. With respect to CCS, the scope of technical, financial, regulatory, and legal considerations is extremely complex. It is imperative that EPA consider all major assessments of CCS development and continue to expand the scope of information considered in the BSER analysis to include the full range of available major assessments and other more relevant information.

For example, among the most relevant and comprehensive information to consider are the experience and lessons learned from the AEP Mountaineer CCS project. Since 2012, AEP has submitted over 1,200 pages of comments on proposed 111(b) and 111(d) rulemakings, including extensive comments on the Mountaineer Project. Yet the information submitted does not appear to have been considered by EPA in the BSER determination process. In fact, neither the proposed rule, nor the RIA make a single reference to Mountaineer. The lack of close, or any, consideration of the Mountaineer project (the first demonstration of CCS on a coal-fired power plant) in the BSER review demonstrates that EPA's current analysis is incomplete and the resulting BSER determination is premature.

For many years, strategies to reduce GHG emissions have been contemplated by policymakers, driven research and development, and influenced electric utility planning. Increasing attention by policymakers has led to a general acceptance that at some future point, a GHG reduction program would be implemented, although the scope and timing of requirements were and remain unknown. In planning for the possibility of GHG regulation, the electric utility community has considered potential emission control technologies and broader reduction strategies that may become available. In parallel, the U.S. Department of Energy, along with other public and private efforts, have correctly (and consistently) recognized that potential $CO_2$ emission reduction technologies, including CCS for fossil fuel-based electric generation processes, must overcome significant development barriers if they are to have any chance of becoming a technically feasible and commercially viable control option.

Recognition of the likelihood of $CO_2$ regulations and speculation on the potential availability, cost, and performance of CCS and other reduction strategies is helpful in attempting to forecast future needs, as well as to guide research and development efforts to meet those needs. However, this recognition is not an affirmation or an endorsement that CCS is currently, or ever will be, technically feasible or adequately demonstrated as a $CO_2$ emission control option for fossil fuel-based power generation.

While lowering capture and compression costs is a significant challenge, it is only one of many that impede the prospects of CCS becoming technically feasible, adequately demonstrated, and commercially viable. Focusing primarily on capture costs alone understates the breadth of barriers by downplaying the significant technical challenges that exist for capture systems and the equally significant technical, cost, and legal challenges for transport and storage systems. These challenges cannot be addressed merely through desktop studies, research papers, engineering exercises, or technical specifications. It is critical that solutions to these challenges are developed and physically demonstrated with proven performance at a commercial-scale, while being exposed to the full gamut of commercial-scale power plant conditions. These solutions are a prerequisite to CCS becoming a technically feasible and adequately demonstrated $CO_2$ control option. Successful development must be advanced in a systematic and stepwise manner. AEP began the process of advancing CCS to a commercial scale. With the suspension of the AEP project and delays or discontinuations of other CCS projects, the date for the true commercial readiness of CCS technology continues to move farther into the future.

In summary, increased policy, research, and planning efforts focused on CCS development have advanced the knowledge of challenges and opportunities, but significant time and investment must still be spent to address remaining development barriers. While efforts have advanced the knowledge and state of CCS technologies, CCS has still not been demonstrated to be the BSER. At the current pace of development, CCS is a number of years from being adequately demonstrated and that time will certainly be beyond the compliance timelines proposed by this rule.

**B. Technical feasibility is not the same as adequately demonstrated**

Varying degrees of technical feasibility can be determined through desktop calculations, laboratory studies, pilot-scale testing, large-scale demonstrations, or other methods. As such, a process that is technically feasible is not necessarily adequately demonstrated or commercially viable. A determination of adequate demonstration cannot be made until sufficient research, development, and demonstration occur that validate the feasibility of the technology at a commercial scale on representative processes, allow for the optimization of systems integration and performance, and provide for cost-effective design options that can be safely and reliably operated. Absent this process, a technically feasible process remains just that – technically feasible and no more. Currently, CCS has yet to be adequately demonstrated at a commercial scale on a coal-based electric generating unit.

**C. AEP's Mountaineer project demonstrates that CCS is not yet the BSER**

From 2009 to 2011, AEP operated the world's first integrated CCS project on a coal-based generation plant. In prior Section 111(b) and 111(d) proposals, AEP submitted extensive comments to EPA that described the Mountaineer Plant CCS project, discussed lessons learned, and summarized key challenges for CCS to become a technically feasible and commercially viable technology. AEP's comments attempted to alleviate prior misconceptions by EPA by placing into proper context the scope and outcome of its CCS program. Those prior comments remain valid and are attached in Appendix A for incorporation into this comment submittal.

AEP has been a strong advocate for the development and advancement of CCS technologies and believes that technological solutions are critical to reducing emissions from and improving the performance and reliability of electric generation processes. Nonetheless, as an outcome of our first-hand experience and as reinforced by other public and private efforts, AEP is convinced that CCS remains many years from being proven to be a technically feasible, adequately demonstrated, and commercially viable solution for reducing $CO_2$ emissions.

Several qualifications are necessary to understand what was and was not accomplished by the Mountaineer project. AEP did not construct or operate a full-scale capture CCS system. AEP did successfully deploy a $CO_2$ capture system on a validation scale slip-stream process (20 MW electric equivalent, or 1.5% of the Mountaineer Plant's 1,300 MW capacity). The project successfully proved that the technology was compatible with plant operations and could capture $CO_2$ at a coal-fired power plant. AEP went on to complete the early stages of a commercial-scale project, including performing a front-end engineering and design (FEED) study. However, after being unable to obtain the necessary cost-recovery approval from state regulators, the project was cancelled. It should be clearly understood that the validation project did not constitute a commercial demonstration and that the technology was not, and has yet to be, proven to be adequately demonstrated at a commercial scale.

The validation project involved AEP partnering with Alstom to validate their chilled ammonia capture process. The system operated from September 2009, through May 2011. It captured more than 50,000 metric tons of $CO_2$ over that period. The system was built as a validation platform with flexibilities for systematic process adjustments, which enabled operators to optimize and control all process streams and energy inputs to thoroughly evaluate the technology. The project team developed a comprehensive understanding of the chilled ammonia process and specifics about the operation of each system within the process. This background, including a detailed understanding of key process parameters, such as energy penalty, reagent loss, and $CO_2$ capture rate, facilitated moving forward with the FEED study for a commercial-scale project.

While the capture process was shown to be technically feasible under coal-fired power plant conditions, many important aspects of the technology remain to be demonstrated at full-scale (a minimum of approximately 235-MWe, or roughly 12 times the size of the validation system at Mountaineer) before a process supplier or power plant owner could realistically consider deploying the technology commercially on even the smallest of coal-fired power plants. For example, post-combustion $CO_2$ capture technologies typically require massive amounts of thermal energy, which is supplied using enormous quantities of steam. That steam is most efficiently taken from the existing power plant boiler/steam-turbine system, which represents a significant power generation heat cycle change and requires a steam path redesign and modification of the generating unit. Once completed, the modifications intrinsically tie together the generating unit with the $CO_2$ capture system, changing the original design of the plant. Such a newly designed integrated system has never been demonstrated and must be rigorously tested, under the wide range of commercial operating conditions, and optimized before the technology can be deemed reliable, proven, or commercially viable. In addition, the equipment to capture $CO_2$ is large and an entire system capable of treating the effluent of a power plant requires extensive tracts of land. In the AEP/Alstom study of a commercial scale installation, the system was designed to capture 265 MWe worth of flue gas (approximately 1/5 of the plant output), yet it occupied a footprint nearly the same size as the original power plant, or over 10 acres. Size alone would preclude use of the capture technology at many existing power plants, and this must be carefully considered in the design of any new power plant.

Separately, AEP partnered with Battelle to study and validate sequestration of $CO_2$ into deep saline reservoirs near the Mountaineer Plant. Approximately 37,000 metric tons of the captured $CO_2$ was compressed and injected into two saline reservoirs located roughly 8,000 feet beneath the plant site. Besides two injection wells, one into each of the reservoirs, AEP deployed three deep monitoring wells at various distances from the injection point. Many experimental and novel monitoring technologies were also tested at the site. The difficult nature of the geology in the area proved some of these technologies to be inappropriate for the application. Again, while the project was successful in injecting and confining the $CO_2$ sent to the wellheads, the scale was far from being representative of what would be required for full-scale deployment. The potential for CCS to be successful at any given plant site will be highly dependent upon the suitability of local geologic conditions. Furthermore, great uncertainty remains surrounding the liability for and future ownership of injected $CO_2$, which could dissuade any future developer.

Any commercial-scale CCS project is going to be very expensive. The commercial-scale CCS project that was considered for the Mountaineer Plant would have captured 90% of the $CO_2$ from 20% of the flue gas. The conceptual project cost of $668 million escalated to approximately $1 billion after the FEED study was completed. These costs were expected to continue to escalate throughout the detailed engineering, construction, and commissioning phases of the projects. One cost that was not fully included in the $1 billion estimate relates to uncertainties about the cost to comply with requirements of the underground injection control (UIC) permit. Although the project was cancelled prior to even filing an application for a UIC permit, it was estimated based on the requirements in the Class VI UIC Guidelines that the project could have been required to install an additional 75 intermediate and deep monitoring wells at an estimated cost of nearly $300 million – a 30% increase in the estimated $1 billion CCS project – which again represented only 20% of the plant output. Present day costs would most assuredly be significantly higher.

A review and discussion of the lessons learned from the Mountaineer CCS Program were documented in several reports submitted to the Global CCS Institute ("GCCSI"). EPA has been strongly encouraged to review and apply the information from these reports in associated BSER evaluations. These reports are readily accessible through the GCCSI website,[3] including the following:

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[3] www.globalccinstitute.com

- CCS Lessons Learned Report: AEP Mountaineer CCS II Project Phase 1
- AEP Mountaineer II Project – Front End Engineering and Design (FEED) Report
- AEP Mountaineer CCS Business Case Report

EPA is also encouraged to review the draft Environmental Impact Statement for the Mountaineer commercial-scale demonstration project to gain greater perspective on the scope and magnitude of issues that any CCS project must address. It is especially revealing that these significant challenges are only for a 20% capture project. A requirement to capture 40%, 60% or more would create a level of barriers that could be too prohibitive for most, if not all, project developers to overcome. The draft EIS can be found on the DOE website.[4]

In conclusion, while the AEP Mountaineer project proved that CCS is promising for future plant applications, it remains many years and multiple development stages from being proven at a true commercial scale, still requires development of an appropriate regulatory or legal framework and is largely dependent on site-specific characteristics. As a result, CCS has not yet been demonstrated to be the BSER.

D. **DOE Technology Readiness Levels demonstrate that CCS is not yet the BSER**

The U.S. Department of Energy publishes a biannual report entitled "Carbon Capture Program R&D Compendium of Carbon Capture Technology".[5] Contained within the 718 pages of the 2022 edition is a detailed summary describing 60 unique projects focused on post-combustion capture of $CO_2$ from power generation sources, both coal and natural gas. The technologies in this report range in Technology Readiness Level (TRL) from a TRL-2 (Technology concept and/or application formulated) to TRL-7 (Full-scale prototype demonstrated, final design virtually complete.)[6] According to DOE's TRL system, TRL-8 means that an actual system has completed and qualified through test and demonstration. TRL-9 means an actual system has operated over the full range of expected conditions. BSER must describe technology, and arguably more than one demonstration of the technology, that has achieved TRL-9, a full two steps further than the current state of the art in post-combustion $CO_2$ capture. In DOE's report, the most advanced technologies are in the process of completing or have completed Front End Engineering & Design (FEED) studies but have not progressed to actual construction and operation. The following are three examples from the 2022 Compendium that appear to be the furthest along:

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[4] https://www.globalccsinstitute.com/resources/publications-reports-research/mountaineer-commercial-scale-carbon-capture-and-storage-project-draft-environmental-impact-statement-summary/

[5] https://netl.doe.gov/node/12134

[6] https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04a-admchg1/@@images/file]

- On page 63, a FEED study was completed just one year ago for the design of a post combustion carbon capture system that **could be** installed on an 816 MWe coal plant "**to become** the largest post-combustion carbon dioxide ($CO_2$) capture plant in the world." [emphasis added]
- A FEED study on page 83 aims to support a "**business case for construction and operation** of Fluor's EFG+ technology to capture 90% (11,000 tonnes/day) of the $CO_2$ from the flue gas of the 477-megawatt-electric (MWe)" [emphasis added]. At the point of publication of DOE's compendium, the FEED study was 80% complete.
- On page 69, it states of the Flour Econamine FG Plus $CO_2$ capture process, "This **FEED study could lead to the world's first commercial deployment** of carbon capture on a natural gas-fired power plant and could be duplicated at other power plants across the world." [emphasis added]

These projects are engineering studies based on much smaller validation work, they are NOT YET operating plants. While there are far more projects in development today than when AEP and Alstom completed a commercial scale FEED study for Chilled Ammonia at Mountaineer Plant, none of these technologies has been demonstrated at commercial scale under the full range of hot operating conditions. EPA calling these technologies BSER does not automatically leapfrog them from TRL-6 or 7 to TRL-9. The only way to get these technologies to BSER is through real-world installation and operation under the wide range of power plant conditions and dispatch dynamics, an evolution of development that will take several more years IF the projects move with haste to the next steps.

E. **Numerous Public and Private Efforts demonstrate that CCS is not yet the BSER**

Other assessments by public and private organizations recognize that CCS has not been proven to be adequately demonstrated for coal or gas generating units. Significant development barriers remain in both applications. In a May 12, 2023, Reuters article, former assistant administrator of the USEPA Office of Air and Radiation Jeff Holmstead said:

> "There isn't a single commercial-scale gas-fired power plant anywhere in the U.S. — or as far as I know, anywhere in the world — that uses CCS to control its emissions," he said. "This fact alone could make it hard for EPA to convince the courts that CCS has been adequately demonstrated."[7]

The Global CCS Institute is an organization whose mission is to accelerate the deployment of carbon capture and storage (CCS). As part of the body of research, data and information maintained by the Global CCS Institute, the organization has developed a CCS facilities and projects database.[8] Below is table of U.S. power generation industry related projects from the database, indicating the type and status of the facility, and the expected operational date. The table clearly shows that there is not a single commercial power generation CCS facility currently in operation in the U.S.

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[7] https://www.reuters.com/sustainability/bidens-power-plant-proposal-poses-huge-test-carbon-capture-2023-05-12/

[8] https://co2re.co/FacilityData

| Facility Name | Facility Category | Facility Status | Operational |
|---|---|---|---|
| Cane Run CCS | Commercial CCS Facility | Early Development | |
| Clean Energy Systems BiCRS Plant - Madera County | Commercial CCS Facility | Early Development | 2027 |
| Clean Energy Systems Carbon Negative Energy Plant - Central Valley | Commercial CCS Facility | Early Development | 2025 |
| CPV Shay Energy Center (CPV West Virginia Natural Gas Power Station CCS) | Commercial CCS Facility | Early Development | |
| Dave Johnston Plant Carbon Capture | Commercial CCS Facility | Early Development | 2025 |
| Diamond Vault CCS | Commercial CCS Facility | Early Development | 2028 |
| Dry Fork Integrated Commercial Carbon Capture and Storage (CCS) | Commercial CCS Facility | Early Development | 2025 |
| Illinois Allam-Fetvedt cycle power plant | Commercial CCS Facility | Early Development | 2025 |
| Prairie State Generating Station Carbon Capture | Commercial CCS Facility | Advanced Development | 2025 |
| Project Tundra | Commercial CCS Facility | Advanced Development | 2026 |
| Cal Capture | Commercial CCS Facility | Advanced Development | 2027-28 |
| Coyote Clean Power Project | Commercial CCS Facility | Advanced Development | 2025 |
| Deer Park Energy Centre CCS Project | Commercial CCS Facility | Advanced Development | |
| Gerald Gentleman Station Carbon Capture | Commercial CCS Facility | Advanced Development | 2025 |
| Heartland Hydrogen Hub | Commercial CCS Facility | Advanced Development | |
| James M. Barry Electric Generating Plant CCS Project | Commercial CCS Facility | Advanced Development | 2030 |
| Mustang Station of Golden Spread Electric Cooperative Carbon Capture | Commercial CCS Facility | Advanced Development | |
| Plant Daniel Carbon Capture | Commercial CCS Facility | Advanced Development | |
| Polk Power Station CCS | Commercial CCS Facility | Advanced Development | Under Evaluation |
| Petra Nova Carbon Capture Project | Commercial CCS Facility | Operation Suspended | 2017 |
| Wyoming Integrated Test Center (ITC) | Pilot and Demonstration CCS Facility | Operational | 2018 |
| E.W. Brown 0.7 MWe Pilot Carbon Capture Unit | Pilot and Demonstration CCS Facility | Operational | 2014 |
| Fuel Cell Carbon Capture Pilot Plant | Pilot and Demonstration CCS Facility | Operational | 2016 |
| NET Power Clean Energy Large-scale Pilot Plant | Pilot and Demonstration CCS Facility | Operational | 2018 |
| Mountaineer Validation Facility | Pilot and Demonstration CCS Facility | Completed | 2009 |
| Oxy-combustion of Heavy Liquid Fuels - 15 MW Pilot Test | Pilot and Demonstration CCS Facility | Completed | 2012 |
| Plant Barry & Citronelle Integrated Project | Pilot and Demonstration CCS Facility | Completed | 2012 |
| Pleasant Prairie Power Plant Field Pilot | Pilot and Demonstration CCS Facility | Completed | 2008 |

In an August 1, 2023, letter to the EPA Administrator, thirty-nine U.S. senators have also called attention to the lack of support for concluding that CCS has been adequately demonstrated. The letter points out that

> "Today, CCS is not commercially operational for any coal or natural gas plant in the United States and even with the 45Q tax credit, CCS is not viable at commercial scale yet."[9]

The letter also highlights several other shortcomings in the proposed regulations, including the co-firing of low GHG hydrogen, which the letter refers to as a nascent technology and dependent on an infrastructure that does not exist today.

A 2022 Congressional Research Services report noted that

> "There is broad agreement that costs for constructing and operating CCS would need to decrease before the technologies could be widely deployed."[10]

Prior AEP comments to EPA provided a comprehensive summary of other assessments and can be found attached in Appendix A. These assessments consistently conclude that the scope and progress of CCS development programs are insufficient to drive the near-term completion of successful commercial-scale CCS projects whose operating experience is needed to adequately demonstrate the technology.

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[9] https://subscriber.politicopro.com/f/?id=00000189-b2bc-d1b8-adff-f3fef9ee0000

[10] Congressional Research Services. Oct 2022. "*Carbon Capture and Sequestration in the United States.*" R44902. P.2

**5. Practical challenges to carbon capture development must be overcome before CCS can be adequately demonstrated to be the BSER**

Apart from the complex consideration of the appropriate interpretation and application of NSPS regulatory language, a host of practical considerations for CCS development exist that represent significant challenges to any CCS project. In many cases, these practical considerations are more of a barrier to the adequate demonstration and commercialization of CCS than the technology itself.

**A. CCS is not just another emissions control technology**

The scope and complexity of development and power plant integration issues for CCS are dramatically different than for other bolt-on emission controls, such as flue gas desulfurization (FGD) or selective catalytic reduction (SCR) technologies. Shoehorning the development of CCS into the "typical" development curves of FGD or SCR technologies is an imperfect comparison that produces a false perception of the steps, timeline, and complexity for CCS development and in no way establishes the standard for or offers guarantees on the success of CCS development.

The CCS development challenges at coal-based power plants are unique from other technologies and are not one-size-fits-all for all potential projects. This is attributed to a greater complexity of process integration issues, the magnitude of operational considerations, and the significant increases to cost of electricity production. CCS also presents unique issues regarding the enormous amounts of $CO_2$ byproduct that must be handled, transported, and stored in geologic formations. For example, coal-combustion ash and FGD-related by-products are solid materials that can be handled and stored in a landfill, while $CO_2$ is generally captured and compressed to a supercritical fluid, which must be stored in deep geologic formations, and will be subject to a more extensive and diverse set of regulatory and legal requirements. EPA acknowledged in their guidance document for PSD permitting for GHG's that the scope of design, construction, and operation considerations are much different and unique for CCS compared to other emission control systems by noting:

> *"EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage."*[11]

[11] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." (Mar. 2011). p. 36. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

Furthermore, CCS development in most cases will depend on the success of external infrastructure non-existent today, such as $CO_2$ pipelines and offsite, underground storage possibly hundreds of miles away. This is a situation much different than an SCR or FGD installation, which are confined to the plant site.

**B. The cost of commercial-scale carbon capture remains a significant unknown**

Regardless of whether the current state of CCS development is characterized as first-of-a-kind, nth-of-a-kind, or something in between, the technology is very expensive, which has restricted and, in many cases, prohibited, development. Each example of a potential commercial-scale CCS project on a coal-based generating unit has experienced significant escalation in costs. The wide disparity in the cost estimates of current efforts is indicative that CCS is not a one-size-fits-all technology, that project-specific cost drivers are significant, that reliable estimates of CCS costs are evolving, and that future CCS cost are highly speculative.

**C. The energy required to power capture systems is large and represents a significant development challenge**

The energy demand and parasitic load to power CCS systems is significant. As estimated by the Department of Energy in a study conducted to determine the cost and performance of a post-combustion $CO_2$ capture technology retrofit on a AEP coal-fired unit:

> *"The combined effect of steam and auxiliary power required to operate the* $CO_2$ *capture and compression system is a reduction in the net power output of the unit by approximately 30 percent*"[12]

The significant energy requirements for CCS systems have been widely recognized and reported by others as well, including in a 2022 Congressional Research Services report:

> *"the amount of energy a power plant uses to capture and compress CO2… sometimes referred to as the energy penalty or the parasitic load, has been reported to be around 20% of a power plant's capacity."*[13]

For context, assume that a CCS system installed on a 600 MW coal-based power plant would require 30% of the load to operate, or approximately 180 MW. The electricity required to capture $CO_2$ from this 600 MW unit is equivalent to the annual electricity consumed by nearly 125,000 households. If the purpose of the power plant in the example is to meet a customer demand of up to 600 MW, then the

[12] https://netl.doe.gov/sites/default/files/2020-11/Program-Plan-Carbon-Capture-2013.pdf

[13] Congressional Research Services. Oct 2022. "*Carbon Capture and Sequestration in the United States.*" R44902. P.2

plant would have to be oversized to accommodate the large CCS-related auxiliary load or a separate generation source would be required.

Increasing the size of the unit would result in greater coal consumption, greater water usage, and greater emissions, byproducts, additional landfill capacity needs, and water discharges to power the CCS system. The NRG Parrish CCS project (Petra Nova) used an approach whereby a separate 80 MW natural gas fired combustion turbine unit has been constructed for the purpose of powering the carbon capture system. In other words, a separate, uncontrolled $CO_2$ emission source is being constructed solely to power equipment that will capture $CO_2$ emissions from another combustion source.

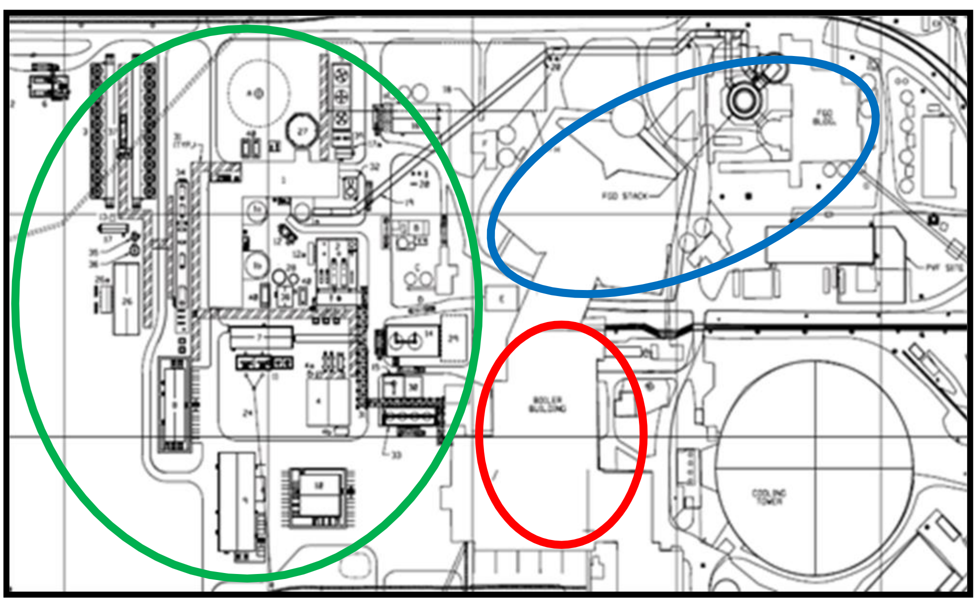
**D. Integrating carbon capture and coal generation operations introduces unique development challenges**

The integration of carbon capture system and coal-based generation operations introduces several unique development challenges that include:

- Integration of Operating Philosophies: The use of CCS represents the integration of two different operating philosophies: power plant vs. chemical plant. Power plant systems are designed to accommodate dynamic operating scenarios where processes routinely cycle in different modes depending on variables such as changes in electricity demand or fuel characteristics. Chemical plants, which is what $CO_2$ capture processes are and largely where these types of systems have operated commercially, are typically designed for steady-state operations with process inputs that have fixed quantities, flow rates, temperatures, and rigid purity specifications. Integrating these philosophies at a commercial scale into a process requiring routine dynamic adjustments presents significant engineering and design challenges whose solutions have yet to be adequately demonstrated as technically feasible or cost effective.
- Capture System Design Specifications: Typical capture systems have stringent process chemistry requirements that demand pristine flue gas conditions that in some cases are well beyond the capability of state-of-the-art FGD and SCR systems. For such systems, additional flue gas polishing systems would be required to accommodate the capture process.
- Capture System Power and Steam Requirements: Energy consumption requirements by the capture system represent one of the most daunting barriers to economical CCS deployment. Current estimates are that operation of the CCS system would demand 25-30% of the net output from the generating unit. Some capture systems consume a substantial portion of that energy through the use of large amounts of steam. The most cost-effective source of steam is typically from the power plant itself, which also impacts overall unit performance and efficiency. These large energy and

steam requirements introduce unprecedented engineering and operating challenges to integrate carbon capture equipment into power plant designs and process flow schemes.

- Footprint of Capture System: The size of the capture systems is a concern as current design configurations would more than double the footprint of a typical power plant, which introduces substantial implications with respect to siting, constructability, and project costs. For example, the capture system for the AEP commercial-scale Mountaineer Plant CCS project would have encompassed over 10 acres, which is over double the footprint of the generating unit itself. Notably, the footprint for the Mountaineer Plant capture system was for a system designed to capture only 20% of output from the unit. While some economies of scale would be expected through process and design optimization, the capture system footprint will remain very large. The large footprint is also another example of the magnitude and complexity of equipment and systems within the capture process, which introduces significant performance and reliability challenges. In other words, more equipment and larger physical footprint needs introduce greater operational risks. Many operating plants do not have much available land at their plant sites, further complicating the design and operation of such systems. The figure below illustrates the scale of the capture system that was being planned for the 20% $CO_2$ capture system at the Mountaineer Plant.



Mountaineer 1300 MW Power Block

SOx / NOx / PM Controls

20% CCS System

- Unit Availability Risks from Geologic Storage and Enhanced Oil Recovery (EOR) Processes: Operation and performance risks specific to the geologic storage or EOR systems introduce integration concerns as these risks can impact the performance or constrain the operation of the capture system and power plant. For example, a CCS project aligned with an EOR system would be constrained by the assurance that the demand for $CO_2$ from the EOR operator always meets or exceeds the $CO_2$ produced by the power plant. When the demand for $CO_2$ from the EOR operator is insufficient, then the power plant would be forced to vent captured $CO_2$ to the atmosphere, curtail operations or shutdown. Power plants are developed, and in many states are regulated, based on being able to reliably meet a specified demand for electricity – an essential public need. Subjecting the availability of power generation to the availability of EOR operations fails to ensure that the obligation to provide reliable power can be met. Likewise, similar constraints are reasonably expected to occur with geologic storage systems where a host of known and unknown variables could constrain the availability and performance of injection wells. AEP experienced these types of constraints during the operation of the validation-scale CCS project. The scope of these risks coupled with legal and regulatory uncertainties associated with long-term geologic storage is another indication that CCS has not been adequately demonstrated to be technically feasible or commercially viable.

**6. Practical challenges to $CO_2$ pipeline and storage development must be overcome before CCS can be adequately demonstrated to be the BSER**

**A. Undeveloped regulatory and legal considerations may alone prohibit CCS development**

A broad scope of legal and regulatory uncertainties exist that apply to each aspect of the CCS process (capture, transport, and storage), which must be addressed before any CCS project can be developed. A discussion of these issues follows to provide context on the breadth of issues that remain to be resolved and to demonstrate the significant challenge they pose to CCS development. Unknowns exist regarding how these issues will be addressed within state boundaries, and with respect to interstate considerations. A study by the West Virginia Chamber of Commerce surveyed all 50 states to assess the readiness of their state regulations and policies to accommodate CCS projects. Most states were not well prepared and were not proactively preparing programs to regulate CCS projects, as summarized below:[14] No evidence has been identified that state regulations have significantly advanced to address these issues since the time that this study was published.

| | Obtained UIC Class VI Permitting Primacy* | Identified Property Rights to be Secured | Streamlined procedures for the taking, unitization or use of property rights | Addressed Long-term Care Provisions | Streamlined procedures for the siting or construction of $CO_2$ pipelines |
|---|---|---|---|---|---|
| States that responded | 0 states (0%) | 14 states (28%) | 8 states (16%) | 12 states (24%) | 11 states (22%) |

* After the completion of the WVCOC report, two states have since been granted primacy for the Class VI permitting program.

The development challenges related to legal and regulatory issues have been recognized in many assessments, including the following:

- Global CCS Institute: "Despite regulatory developments, the topic of liability continues to be considered by some CCS project developers, policy-makers and regulators as a critical issue and potential 'show-stopper' for the technology's deployment."[15]
- William & Mary Environmental Law and Policy Review: "Concerns about potential liability would hence be an important barrier to developing CCS projects." (p.410) and "the most important barrier to successfully developing CCS is precisely the potential liability for long-term stewardship" (p. 468)[16]
- Interagency Task Force on CCS: "for widespread cost- effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship" and that "regulatory uncertainty has been widely identified as a barrier to CCS deployment."[17]
- Secretary of Energy's National Coal Council:"[t]he management of long-term liability risks is [a] critical consideration for CCS projects...[U]ncertainty regarding long-term liability options remains a challenge."[18]

**B. Uncertainty regarding property rights issues is a barrier to CCS development**

Key questions related to property rights that must be resolved include:

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[14] "A State-by-State Survey of Existing Statutes and Rules Related to the Transportation and Geologic Storage of Carbon Dioxide" (March 20, 2014). West Virginia Chamber of Commerce. EPA Docket ID: EPA-HQ-OAR-2013-0495-4733

[15] Global CCS Institute. (2019) "*Lessons and Perceptions: Adopting a Commercial Approach to CCS Liability"*

[16] William & Mary Environmental Law and Policy Review. (2016) "*Liability and Compensation for Damage Resulting from CO2 Storage Sites*"

[17] Report of the Interagency Task Force on Carbon Capture and Storage, pp. 10-14 (Aug 2010).

[18] Expediting CCS Development: Challenges and Opportunities, p. 83 (Mar 2011)

- Who holds ownership rights to pore space? Surface-owner, mineral rights-owner, state, or Federal government, other.
- Does surface or mineral-rights ownership mean owners have a protectable interest?
- To the extent that protectable interests exist, are those interests limited to within a specific depth below the surface of the earth?
- Does the use of pore space necessitate the need to acquire access or pore space rights?
- How are pore space rights acquired?
- How do existing programs for eminent domain, unitization, public use, or voluntary acquisition translate to pore space acquisition?
- How does existing eminent domain authority apply to $CO_2$ pipeline development?
- What is the relationship between the use of pore space for $CO_2$ sequestration and liabilities related to the ownership and use of surface or mineral rights?
- Who has regulatory jurisdiction over issues related to property rights? State utility commissions, state environmental protection agencies, state natural resource departments, etc.

Several options have been identified for resolving these issues. Addressing each will require time and resources, but most importantly will require a commitment by individual states to proactively resolve these issues and to become prepared to regulate future CCS projects efficiently and effectively. Without these steps, such regulatory and legal issues will remain significant barriers to CCS development.

**C. Uncertainties regarding long-term stewardship and liability are barriers to CCS development**

Considerations related to the long-term care of $CO_2$ that has been geologically sequestered focus on two key issues: stewardship and liability. Stewardship involves the monitoring and assessment of the geologic storage area, while liability relates to responsibility after closure of the injection process. Although the EPA Class VI injection well regulations establish monitoring and post-injection site care requirements for a specified period (50 years post-injection), several uncertainties during and beyond that period remain that must be addressed, including:

- Post-closure requirements for transfer of liability? The federal government and many states have yet to provide a mechanism for the transfer of liability.
- Financial responsibility requirements to assure the availability of funds for the life of the project (including post-injection site care and emergency response)? EPA Class VI rules include some requirements, but how far do these extend into the future?
- Post-closure monitoring requirements? EPA Class VI rules have some requirements, but how far do these extend into the future?

**D. The Class VI UIC permitting process introduces uncertainties to CCS development**

The permitting program for the EPA Class VI underground injection control (UIC) program is in its infancy. Only a handful of states have pursued primacy over the permitting process. EPA has primacy over the permitting process in most states. The application process is extensive and requires information to be provided that will be very time-consuming and expensive to gather and evaluate – if indeed it is even obtainable given the size of the area that must be considered to accommodate the volume of $CO_2$ storage associated with a coal-based generation unit. For example, the Class VI permit must include information such as:

> "*A map showing the injection well...and the applicable area of review consistent with §146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected.*"[19]

As the area of review is likely to be many tens of square miles in size for a commercial- scale project, the research and preparation of such information alone will be a tedious and time-consuming process that will result in a voluminous submittal to the regulatory agency for review. Although it remains to be determined whether the application process itself represents a critical barrier in the development of CCS, we anticipate the permitting process alone will be onerous. Another unknown that remains is how the extensive information provided in the application will translate into the actual permit requirements and whether such requirements would be so onerous to comply with that they could effectively prohibit a CCS project from occurring. For example, based on information in EPA's final Class VI UIC rule regarding the number of monitoring wells that may be necessary, the commercial-scale CCS Mountaineer project could potentially have been required to install an additional 75 monitoring wells at an estimated cost of nearly $300 million, which represented a 30% increase in the estimated $1 billion CCS project cost at the time of the project – again this is for the geologic storage of only 20% of the plant output. Today, costs would most certainly be far greater. These types of unknowns represent significant challenges to the adequate demonstration and development of CCS.

In addition to the time required to prepare the Class VI UIC permit application, the time required for the regulatory agency to process the application and issue a final permit represents a significant development hurdle as well. Archer Daniels Midland filed the very first Class VI UIC permit applications

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[19] 40 CFR 146.82(a)(2)

to U.S. EPA, one in July 2011 and one in December 2011. The final permits were issued in September and December 2014, respectively, a full three years after the applications were submitted. Steps for processing these applications include the issuance of a draft permit, public commenting period, further technical review, and issuance of a final permit. These steps could easily increase the permitting by years. Any potential project cannot move forward with detailed engineering and design, or construction without the necessary regulatory approvals (e.g., UIC permit) in place and without the certainty that related regulatory requirements will be obtainable, cost-effectively, and achievable throughout the operation of the facility.

Finally, the Class VI UIC regulation should not be misconstrued as having addressed all barriers to the geologic sequestration of $CO_2$. As noted in a 2014 report by the Congressional Research Service:

> "*The development of the regulation for Class VI wells highlighted that EPA's authority under the SDWA is limited to protecting underground sources of drinking water but does not address other major issues. Some of these include the long-term liability for injected* $CO_2$*, regulation of potential emissions to the atmosphere, legal issues if the* $CO_2$ *plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected* $CO_2$ *plume, and ownership of the subsurface reservoirs (also referred to as pore space).*"[20]

**E. Interstate and comingling issues are barriers to CCS development**

While the aforementioned questions show how far individual state requirements must mature to be able to accommodate CCS within state boundaries, another layer of complexity occurs when these questions are considered in context with interstate boundaries or with the comingling of geologically stored $CO_2$ from multiple sources. The relationship between individual state regulations on property rights, long-term stewardship, liability, and permitting has, in most cases, not yet been determined for individual injection wells. Likewise, these issues need to be resolved to address the intrastate or interstate geologic storage of $CO_2$ from one source that over time combines with the $CO_2$ stored by another source.

**F. Uncertainties regarding the applicability of RCRA are a barrier to CCS development**

EPA has conditionally excluded $CO_2$ streams captured from power plants and industrial systems as a hazardous waste under the RCRA program if they are injected under a UIC Class VI permit. However, uncertainties remain regarding the extent of that exemption, which could discourage the use of anthropogenic $CO_2$ for EOR operations. Although EPA notes in the final rule revising the RCRA

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[20] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" (Feb 10, 2014). Folger, P. Congressional Research Service. p. 23

requirement that the injection of $CO_2$ for EOR or other commercial purposes "would not generally be a waste management activity," questions remain regarding RCRA applicability when the EOR process ends or if the process becomes solely a geologic storage operation.

**G. Geologic storage may be the greatest challenge to the development of CCS**

The complex technical and financial uncertainties and concerns related to geologic storage are significant and may represent the greatest barriers to the technical feasibility, adequate demonstration and commercialization of CCS. The availability of suitable saline formations, geologic injection pressure limitations, and the ultimate storage capacity of formations, as well as monitoring and verification methods are all currently the subject of intense study and lack large-scale data for proof-of-concept soundness. Unfortunately, EPA greatly downplays and ignores most of these issues in its BSER analysis.

A primary concern is with understanding the geology itself where characteristics may be highly variable even within a close area; where techniques to assess these characteristics are expensive and time consuming to perform; and where resources to evaluate such data through modeling or other means may not be able to assess underground conditions adequately or reliably. Consider, for example, the efforts to assess the geology near the AEP Mountaineer Plant. From 2003 to 2007, over $7.5 million was spent to perform extensive surface and subsurface testing, including modeling and analyses, to characterize the geology near the plant and to assess its feasibility for $CO_2$ storage. Results provided sufficient information to support the development of the validation-scale CCS project at the Mountaineer Plant. The validation-scale project included the development of additional wells for $CO_2$ injection and for monitoring purposes. Geologic data from characterization of these wells and the experience gained from operations greatly expanded the knowledgebase of the geology near the Mountaineer Plant.

Despite this extensive geologic knowledge obtained beginning with the initial characterization in 2003 and carried through the operation and monitoring of the validation facility, the information was insufficient to evaluate the geology and design the injection wells associated with the planned commercial-scale CCS program. Prior to the commercial-scale program being discontinued, one additional geologic characterization well was drilled approximately 3 miles from existing wells at the site. Even at this short distance, changes in the geologic characteristics were being noted that would have required several additional characterization wells to be drilled had the project moved forward. At a cost of approximately $5 million per well and over 6 months to obtain the well works (drilling) permit, other environmental-related permits, and to conduct the drilling activity itself, the level of effort needed to obtain these additional characteristics is not a small undertaking. If suitable geology cannot be found locally, then a more comprehensive study of potential regional locations would be necessary, which adds time and costs to the project.

In addition, technologies to monitor and verify the location of the injected $CO_2$ are needed, whose capabilities, performance, and durability have not yet been proven for such applications. While experience from the oil exploration and production industries is beneficial, it is not a substitute for the lessons learned from operating enough large-scale demonstration projects involving the injection of $CO_2$ in saline and other formations. Separately, a demand for more reliable geologically based computer models remains, which, in part, requires a time-consuming, expensive, and rigorous validation process. If proven, these models could potentially be used to avoid exorbitantly high costs of installing and operating large numbers of monitoring wells, which otherwise may prohibit CCS development.

**H. $CO_2$ pipeline projects present challenges to the development of CCS**

Significant consideration must be given to issues related to $CO_2$ pipeline development. However, these issues pose several schedule, cost, and regulatory uncertainties that can be significant enough to eliminate the prospects of any CCS project. AEP experienced some of these pipeline development challenges in the Mountaineer project's initial design phase alone. For the commercial-scale (20% capture) Mountaineer Plant CCS project, AEP considered pipeline routes to potential injection wells located within 12 miles of the capture process. A common perspective is that pipeline routes could "simply" parallel existing transmission rights-of-way. AEP considered this option and found that it was anything but "simple." For example, existing transmission rights-of-way are commonly specific to above ground structures and would not apply to underground pipeline development. Further, existing rights-of-way agreements are landowner or property specific and do not always provide access to perform geologic evaluations and other access work that is not affiliated with the transmission lines for which the right-of-way was originally granted.

This was the case for the AEP commercial-scale CCS project that planned to develop pipelines along existing transmission line corridors. To access potential pipeline routes for a visual assessment alone required obtaining additional rights-of-entry permissions from landowners. This additional permission was also necessary to perform baseline field studies (e.g. ecological, cultural, and water resources) that were needed to develop applications for permits needed to facilitate construction. Obtaining this access was an onerous undertaking that increased the project cost and development timeline as over 250 landowners were involved. The right-of-way diligence process is onerous and first involved extensive title searches to identify landowners, followed by an extensive outreach to contact landowners, who included residents, businesses, out-of-state descendants, or yet-to-be probated estates.

Many refused to grant access or did so only after much inquiry and effort. But this process reveals the complexity of what otherwise should have been a straight-forward and benign request – to *qualitatively* survey the existing transmission line right-of-way for a *potential* $CO_2$ pipeline and nothing more. Separate permissions would have had to be obtained to construct the pipeline, which undoubtedly would have been more challenging. We know this because AEP has extensive and ongoing work taking place to improve our electrical reliability through rebuilding transmission and distribution lines across our 11-state territory. In our experience, landowner interactions can drive a project, result in condemnation proceedings in court, and add a year or more to a project schedule. For capture projects that require much longer pipeline transport to access geologic storage or EOR systems, a developer would have to obtain rights-of-way from potentially <u>thousands</u> of landowners and obtain permits from multiple local and state jurisdictions. The scale of this effort would dwarf the pipeline development challenges for the Mountaineer Plant CCS project.

Another consideration with pipeline development is that its siting and design are dependent on the siting and design of the $CO_2$ injection wells. As discussed above, the site characterization, design, and permitting of the injection wells is a time-consuming process with considerable unknowns. Even though some preliminary pipeline development activities can occur prior to and in parallel with the development of the injection wells, final pipeline design, permitting, and construction requires certainty on the location of the wells.

These types of challenges underscore the point that development of $CO_2$ transport systems will add significant scope, time, and cost to any CCS project. The impact of these risks should be evaluated in the final rule as EPA considers the overall feasibility and costs of CCS development.

**I. Enhanced oil recovery offers no guarantee of being available or willing to support CCS processes**

The viability of opportunities to utilize $CO_2$-EOR operations for geologic storage faces many challenges, including those associated with the validation and accounting for $CO_2$ storage permanence. Current and past EOR practices have not been required to demonstrate permanent $CO_2$ storage. In some cases, EOR operators have been economically driven to minimize the quantity of $CO_2$ left underground in favor of reusing the injected $CO_2$ in other recovery operations.

EPA indicates in the proposed rule that *"We also emphasize that this proposal does not involve regulation of downstream recipients of captured $CO_2$. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured $CO_2$."* [21] As such, potential

[21] Proposed Rule at 33328

opportunities for EGUS to utilize CO-EOR operations may be limited due to the proximity of EOR opportunities and the willingness of EOR operators to accept the operational risks and regulatory burdens that may come with the use and accounting of injected $CO_2$.

EOR operators are in the business of one thing – timely and cost-effective production of hydrocarbons. They are not in the business of providing reliable, affordable electricity, nor are they in the business of playing an integral role in the definition of a best system of emission reductions for another industry. EOR processes operate when and how they want to operate, outside the influence of electricity demand, power prices, or generation outages. EOR operators are only one component of a larger industry – an industry where competition and opportunities for development continue to expand, especially with the growth of hydraulic fracking and shale-gas extraction techniques. In other words, if the power industry, through the use of carbon capture systems, can provide another supply of $CO_2$ to support EOR operations that is cost-effective, then EOR operators may be willing to use it. But it is not as if EOR operators are waiting in neutral or anxiously anticipating the possibility that power generation-derived $CO_2$ will become available, especially if the timetable for that availability is a significant unknown.

AEP has observed this type of ambivalence from one industry to another in working through the complex process of obtaining permission from coal companies to be able to drill characterization, injection, and monitoring wells in support of the Mountaineer Plant CCS program – a program that could help lead to the continued use of the very product that such companies are producing, coal. In this example, the mineral rights below the surface of planned wells were owned by a coal company. Permission had to first be obtained from the owner to drill through the recoverable coal before a well works (drilling) permit could be issued. Such permission was difficult to obtain and is another challenge to CCS development.

Regulatory challenges for EOR operators may be significant as well. Consider the October 2013 comments from U.S. EPA on the draft environmental impact statement for the proposed Hydrogen Energy California IGCC/CCS project. EPA's comments note that:

> *"According to the PSA/DEIS, hundreds of wells have been installed in the Elk Hills Oil Field for injection and production over the decades of petroleum extraction activity, as well as the thousands of well bores that abound in the site for different purposes and at varying depths of penetration... It indicates that the presence of such a large number of well bores in the seismically active project site creates a potential for leak pathways of injected* $CO_2$*... CEC staff recommends that HECA enter into an agreement with OEHI to require installation of a robust monitoring network capable of detecting leaks.* [EPA] *Recommendation: To the extent practicable, efforts*

*should also be made to locate and permanently seal old wells that could provide a conduit for* $CO_2$ *leakage*."[22]

The prospect of being required to locate and permanently seal "hundreds of wells" and "thousands of well bores" is simply not practical, far outside the typical scope of EOR operations, and alone would likely doom any CCS project from being developed. In a December 9, 2002 letter to state governors, EPA's Administrator, Michael S. Regan reinforced the protection measures found within the UIC Class VI regulations. Among the measures noted was the requirement for proper plugging of wells, and long-term project management and post-injection site care to ensure leakage prevention.[23]

As noted in the comments above, the EPA Class VI UIC permitting experience to date indicates that the process is time-consuming, and the outcome of requirements is fraught with uncertainties. The time to obtain a Class VI UIC permit, perform detailed engineering and design, and construct a new fossil fuel-fired power plant equipped with CCS could easily require five to seven years or more. Aligning such a lengthy and uncertain development time frame with the business plans of an EOR operator represents a significant challenge to any CCS project. It is premature to believe that the EOR experience to date could readily accommodate the requirement to install CCS technologies on fossil-fuel based generating units.

Another DOE report indicates that the EOR experience to date cannot be assumed to be sufficient to readily accommodate regulated CCS technologies. This report was authored by Dr. James Dooley and others at the Pacific Northwest National Laboratories ("PNNL"). Several statements in the PNNL EOR report are particularly noteworthy and suggest that EOR opportunities are not readily available to support power plant CCS systems, including:[24]

- *"$CO_2$-EOR as commonly practiced today does not meet the emerging regulatory thresholds for $CO_2$ sequestration, and considerable effort and costs may be required to bring current practice up to this level."* (p. 5)

[22] U.S.EPA Region IX Comments on Preliminary Staff Assessment/Draft EIS (CEQ#20130210) for HECA project. (October 24, 2013). p. 12

[23] See generally Administrator Michael S. Regan, Underground Injection Control Class VI Letter to Governors (December 9, 2022), https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.

[24] "CO2-driven Enhanced Oil Recover as a Stepping Stone to What?". Dooley, et.al. Pacific Northwest National Laboratory. (July 2010). PNNL-19557.

- *"[O]ur research suggest that $CO_2$-EOR is dissimilar enough from true commercial- scale CCS – the vast majority of configurations likely to deploy – that it is unlikely to significantly accelerate large scale adoption of the technology"* (p.3)
- *"The paper concludes....that estimates of the cost of $CO_2$-EOR production or the extent of $CO_2$ pipeline networks based upon this energy security-driven promotion of $CO_2$-EOR do not provide a robust platform for spurring the commercial deployment of carbon dioxide capture and storage technologies (CCS) as a means of reducing greenhouse gas emissions."* (p. 2)
- *"The authors remain skeptical of arguments for expanded $CO_2$-EOR that are, at their core, extrapolations of what happened in the past in an effort to address energy security concerns, a fundamentally different motivation than stabilizing atmospheric concentrations of GHGs."* (p.16)
- *"The vast majority of $CO_2$-EOR projects inject $CO_2$ produced from natural underground accumulations; in the U.S. and Canada, naturally-sourced $CO_2$ provides an estimated 83% of the $CO_2$ injected for EOR"* (p. 4)

**J. <u>Extensive permitting introduces schedule and financial challenges to CCS projects</u>**

Permitting-related challenges to the viability of any CCS project include:

- The size of a CCS project (capture, transport, and storage systems) requires extensive field studies to evaluate ecological, cultural, water resources etc. to support permit applications;
- The complexity of issues involved with developing a CCS project falls under the jurisdiction of local, state, and federal regulatory agencies. This adds significant complexity with regard to coordinating overlapping and, at times, conflicting requirements between agencies; and
- Inexperience in permitting CCS related issues by the developer and the regulator adds time to the permitting process, as well as uncertainty in the stringency of the final requirements.

These challenges will significantly impact project schedule and finances. Each step within this process not only adds scope and time to the project, but also comes with uncertainty regarding various regulatory approvals and pitfalls that may result from authorization to perform field studies and construction activities. Simply, the permitting process for the pipeline and well aspects of a CCS project alone could take *years* to resolve before construction could even begin.

**7. Natural gas co-firing is not the BSER for existing steam EGUs**

**A. Co-firing with natural gas is not a viable option across the existing coal-fired fleet**

As recently as 2019, USEPA concluded that natural gas co-firing was not BSER.[25] While natural gas co-firing in low quantities is arguably a proven and technically achievable option for coal fired EGUs, it is only utilized at a small number of sites and typically in very low quantities. Further, for those facilities that may already utilize natural gas co-firing in small quantities, it's not just a matter of opening the valve a little more to achieve co-firing rates of 40% on a consistent basis. Unless the supply pipelines are constructed at significantly higher capacities than what is currently needed, there would be a need for constructing new pipeline infrastructure to support the higher co-firing rates.

For most of the units in which natural gas is not already available on site, co-firing would be cost prohibitive, considering the $5-10 million per mile cost of pipeline required. While a shorter pipeline (e.g., 10 miles) may not seem unreasonable, not all sources are within 10 miles of an available gas pipeline. If the pipeline needed to access these natural gas supplies is more on the order of 100 to 200 miles, then these costs can quickly become prohibitive. These are significant costs, especially considering that 40% natural gas co-firing only allows for the unit to be operated until December 31, 2039, before it must be retired. Regardless, a determination of whether a coal-fired EGU can utilize co-firing requires that a site-by-site analysis be performed to determine that answer. Accordingly, because co-firing cannot be applied across all units of a specific type, then it is not appropriate to conclude that co-firing natural gas in a coal-fired steam generator is the BSER.

The difficulty and risks of getting approval, and the costs associated with pipeline development is unpredictable. A good example is the Mountain Valley Pipeline project. The Mountain Valley Pipeline project is a natural gas pipeline system that spans approximately 303 miles from northwestern West Virginia to southern Virginia and is expected to provide up to two million dekatherms per day of firm transmission capacity to markets in Mid and South Atlantic regions of the United States. In February 2018, at the start of the project, Equitrans Midstream Corp (the lead partner in the project) estimated that the pipeline would cost approximately $3.5 billion and would be placed into service by late 2018. However, the project has faced delays associated with several vacated federal and state permits and has faced lawsuits by environmental and local groups opposed to the project. Challenges associated with the project have risen to the Supreme Court. As of today, the project has still not been completed and the cost has risen to approximately $6.6 billion.[26]

[25] 84 Fed. Reg. at 32,544
[26] https://www.reuters.com/business/energy/us-mountain-valley-natgas-pipe-closer-construction-after-wv-permit-2023-06-13/

**B. The short duration of co-firing natural gas before the unit must retire impacts the feasibility of investments being made in pipeline infrastructure**

Under the proposed rule, an existing coal-fired steam generating unit that utilizes the option of natural gas co-firing to allow for operation to continue through 2039 is very much dependent on the natural gas pipeline infrastructure nearby. With a compliance date of January 1, 2030, and a specified retirement of no later than 2040, the operational life as a 40% natural gas co-fired unit is limited to 10 years. Accordingly, the availability of the natural gas pipeline infrastructure in proximity to the facility will play a large part in the feasibility of the project from an economic standpoint.

**8. Hydrogen co-firing is not the BSER for natural gas combustion turbines**

While hydrogen combustion in natural gas-fired combined cycle units is a promising technology, it does not yet meet the standards of BSER due to significant challenges related to hydrogen supplies, transport infrastructure, storage, and utilization.

**A. Hydrogen Co-Firing at the quantities proposed has not been adequately demonstrated.**

EPA's conclusion that hydrogen co-firing is the BSER is insufficient for the following reasons:

- Current combustion turbine technology does not support the combustion of 96% hydrogen as a co-fired fuel. Technical feasibility of combusting hydrogen at these quantities has not been demonstrated. While future improvements to combustion turbine technology may allow for high percentages of hydrogen co-firing, current technology only supports low percentages of hydrogen co-firing (less than 30%).
- Hydrogen co-firing has not been adequately demonstrated. To date, there has been no demonstration of 96% hydrogen co-firing on a commercial natural gas combined cycle unit. In fact, the testing that has been completed thus far has been at very low ratios of hydrogen to natural gas and only for very short periods of time. The highest ratio of hydrogen combustion in an NGCC to date that we are aware of is 44% by volume at New York Power Authority's Brentwood Site.[27] The achievement of 44% by volume co-firing for less than 2 hours in no way demonstrates that 96% by volume is adequately demonstrated for commercial use on a continuous basis at NGCC facilities.
- Even if hydrogen co-firing had been adequately demonstrated, the emission standard would need to recognize that natural gas combustion would still be required at startup of a combustion turbine. If a standard would be finalized, it would need to consider the need for natural gas combustion at startup and higher $CO_2$ emission rates during load change periods such as startup and shutdown.

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[27] https://www.powermag.com/nypa-ge-successfully-pilot-hydrogen-retrofit-at-aeroderivative-gas-turbine/

### B. Challenges to achieving significant levels of hydrogen co-firing

Many challenges to co-firing significant levels of hydrogen currently exist and will continue to exist for decades. These challenges are virtually ignored in the proposal and instead the assumption is made that somehow, someway, all these challenges are going to be eliminated and in very short order. Following is a list, not to be considered all inclusive, describing some of the challenges or roadblocks that currently exist.

- If a green hydrogen (hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity) supply is going to be specified as the only acceptable fuel supply, cost effectiveness and availability will be a challenge and widespread use will not occur. Any final rule should allow for the use of other supplies of clean hydrogen (e.g. blue hydrogen, turquoise hydrogen, pink hydrogen, and green hydrogen). The inclusion of other clean hydrogen supplies would help by reducing challenges regarding power sector access to a reliable hydrogen supply. Green hydrogen production is expected to be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity. In the Pathways to Commercial Liftoff: Clean Hydrogen report, issued by DOE in March, 2023, challenges to achieving commercialization of green hydrogen industrial scaling were summarized as:

  *For water electrolysis, availability of clean electricity and bottlenecks in electrolyzer components/raw materials will play a critical role in the pace of growth. If electrolysis projects fail to scale during the IRA credit period, electrolysis may not achieve the necessary learning curves to remain competitive in the absence of tax credits.* [28]

- Existing natural gas pipeline infrastructure is not capable of transporting 100% hydrogen or even high percentages of hydrogen. In fact, it's questionable whether existing natural gas pipeline infrastructure could even safely handle the transport of 30% hydrogen. According to the Department of Energy, "*The high initial capital costs of new pipeline construction constitute a major barrier to expanding hydrogen pipeline delivery infrastructure.*" The Department of Energy cites that "*Research today therefore focuses on overcoming technical concerns related to pipeline transmission, including: 1) The potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines, 2) The need to control hydrogen permeation and leaks, and 3)The need for lower cost, more reliable, and more durable hydrogen compression technology.*" [29] Blending as little as 5-15% hydrogen into the existing natural gas supply would require modifications to the existing natural gas pipeline

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[28] DOE, The Pathway To: Clean Hydrogen Commercial Liftoff, https://liftoff.energy.gov/clean-hydrogen/.
[29] https://www.energy.gov/eere/fuelcells/hydrogen-pipelines

infrastructure. The fact that infrastructure does not exist for transporting even small amounts of hydrogen shows again that the hydrogen firing/co-firing option has not been adequately demonstrated. DOE also states that "converting existing natural gas pipelines to deliver pure hydrogen may require more substantial modifications. Current research and analyses are examining both approaches." The very fact that DOE is referencing "current research" in solving these challenges speaks to how far from commercial viability a hydrogen pipeline system is today. It is clearly not BSER.

- In considering the likelihood of whether a nationwide hydrogen pipeline infrastructure could be developed and ready for use by EGUs as early as January 1, 2032, it must be recognized that adequate codes and standards be available for the safe construction and operation of hydrogen pipelines. The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) has not yet promulgated safety standards for hydrogen pipelines.

**9. Efficiency improvements are the BSER for coal and gas units**

While technologies such as CCS and hydrogen combustion are promising as future options for the electric generating industry, they simply are not ready for widespread use today. The fact that research, development, and first-of-a-kind demonstration projects are still the subjects of massive federal funding through DOE programs speaks loudly to the truth that they are not BSER. Not only are there a multitude of challenges to be overcome for the utilization of CCS or hydrogen combustion at the generating facility, but there is also a daunting lack of external infrastructure that must be addressed prior to determining that these technologies are the BSER. Instead, the BSER for coal and gas units is the utilization of highly efficient generating technologies. Among other things, this conclusion takes into account the cost of achieving reductions and any non-air quality health and environmental impact and energy requirements and also a complete lack of adequately demonstrated applications.

With respect to efficiency improvement opportunities, different generating units have different levels of efficiency improvements available to them due to factors such as original design, location, availability of space, emission controls, and prior improvement efforts. However, there is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed the existing fleet to maintain and improve efficiency through adoption of best practices. Attached in Appendix A are extensive comments on potential heat rate improvement opportunities that AEP submitted in prior GHG proposals.

Section 111(h)(1) of the CAA authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof when it is not feasible to establish a standard of performance.[30] The phrase "not feasible to prescribe or enforce a standard of performance" means, for purposes of section 111(h)(1), that the "application of measurement methodology to a particular class of sources is not practical due to technological or economic limitations."[31] As applied to heat rate improvement opportunities, the Administrator could collect information on actual unit experiences associated with implementation of the suite of measures potentially available, and develop a standard assessment for heat rate improvements that could be evaluated during regular planned outage cycles. Unit operators could submit a report and recommendation to the state that describes the measures evaluated, the lead time necessary to implement the project(s), and the relative cost-effectiveness of the recommended measures, based on the unit's remaining useful life. A reasonable cost-effectiveness threshold could be established, above which measures would not be required. Reports could be submitted to the state agency regarding implementation. In such a manner, available and cost-effective opportunities could be identified and implemented throughout the remainder of the existing units' operating lives. Actions taken to implement the generating unit improvements under such a work practice standard could be classified as "routine maintenance, repair and replacement," and thereby not expose unit operators to the risk of NSR enforcement. Such a standard would allow the greatest possible incorporation of efficiency improvements without disruption to the operation of the existing fleet, protecting electricity reliability and encouraging the development of new technologies. AEP respectfully requests that the Administrator consider the benefits of such an approach.

**10. Case Studies for Implementing the Proposed Rule**

The following are case studies of key questions and considerations for implementing various compliance strategies in the proposed rule. The purpose is to highlight the complexity of issues that must be addressed, the uncertainties in addressing these concerns, and the extensive time required to resolve these issues and implement the requirements. The goal is to provide practical context and important background for EPA to consider in finalizing rule that is achievable and can be readily implemented.

**A. Case Study 1: CCS Questions and Considerations**

Some of the key questions and considerations associated with implementing the carbon capture and storage compliance option include:

(1) Can the capture process support the range of operating conditions experienced by a unit?

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[30] 42 U.S.C.§7411(h)(1).

[31] 42 U.S.C §7411(h)(2).

(2) Does the capture system require a flue gas purity that would require new upstream emissions controls to be installed?

(3) Does the capture system require the need for a new power or steam generating unit to support its operation?

(4) How is the capacity, operation and performance of the existing unit impacted if it must provide auxiliary power or steam to operate the capture system?

(5) Does the existing plant site have adequate land space to install the capture system?

(6) Do capture equipment vendors have the manufacturing capacity to produce and deliver equipment that can be constructed and placed in service by the proposed compliance dates?

(7) Will the capture process cost be affordable enough to be approved by utility commissions?

(8) Has the local geology been fully characterized, tested, and modeled determine its ability and capacity for storing $CO_2$?

(9) Pipeline and geological storage processes should be for third party businesses, not utilities, to permit, design, construct and operate.

   a. What happens if those businesses do not emerge or are not able to support a project?
   b. What happens if those businesses go out of business before the generating unit retires?
   c. Do third parties assume ownership and responsibility of $CO_2$ at the plant fence line?
   d. What happens if the third party has a pipeline or injection well outage?
   e. What happens if the third party doesn't have the pipeline or injection wells installed by the proposed compliance date?

(10) What if compliance dates cannot be achieved due to extended permitting or regulatory approval timelines?

**B. Case Study 2: Natural Gas Co-Firing Questions and Considerations**

Some of the questions and considerations associated with implementing the natural gas co-firing compliance option include:

(1) Are natural gas companies willing to develop the pipeline and other infrastructure to support co-firing for only a limited number of years of operation before the unit must retire?

(2) Is it affordable to invest in the infrastructure needed to supply gas for co-firing?

(3) State Implementation Plans would need to be approved before commencing pipeline construction. Does that allow sufficient time for the new gas supplies to be implemented?

(4) What happens if a gas supplier cannot be identified?

**C. Case Study 3: Hydrogen Co-Firing Questions and Considerations**

Some of the key questions and considerations associated with implementing the hydrogen co-firing compliance option include:

(1) Hydrogen supplier, storage and delivery should be for third party businesses, not utilities, to permit, design, construct and operate.

   a. What happens if those businesses do not emerge or are not able to support a project?

   b. What happens if those businesses go out of business before the generating unit retires?

   c. What happens if the third party has a hydrogen delivery outage?

   d. What happens if the third party doesn't have the hydrogen supply or delivery infrastructure installed by the proposed compliance date?

(2) What happens combustion turbine technology does not advance rapidly enough to accommodate at 96% rate prior to the compliance date?

**11. The Proposed Compliance Timeline is not achievable**

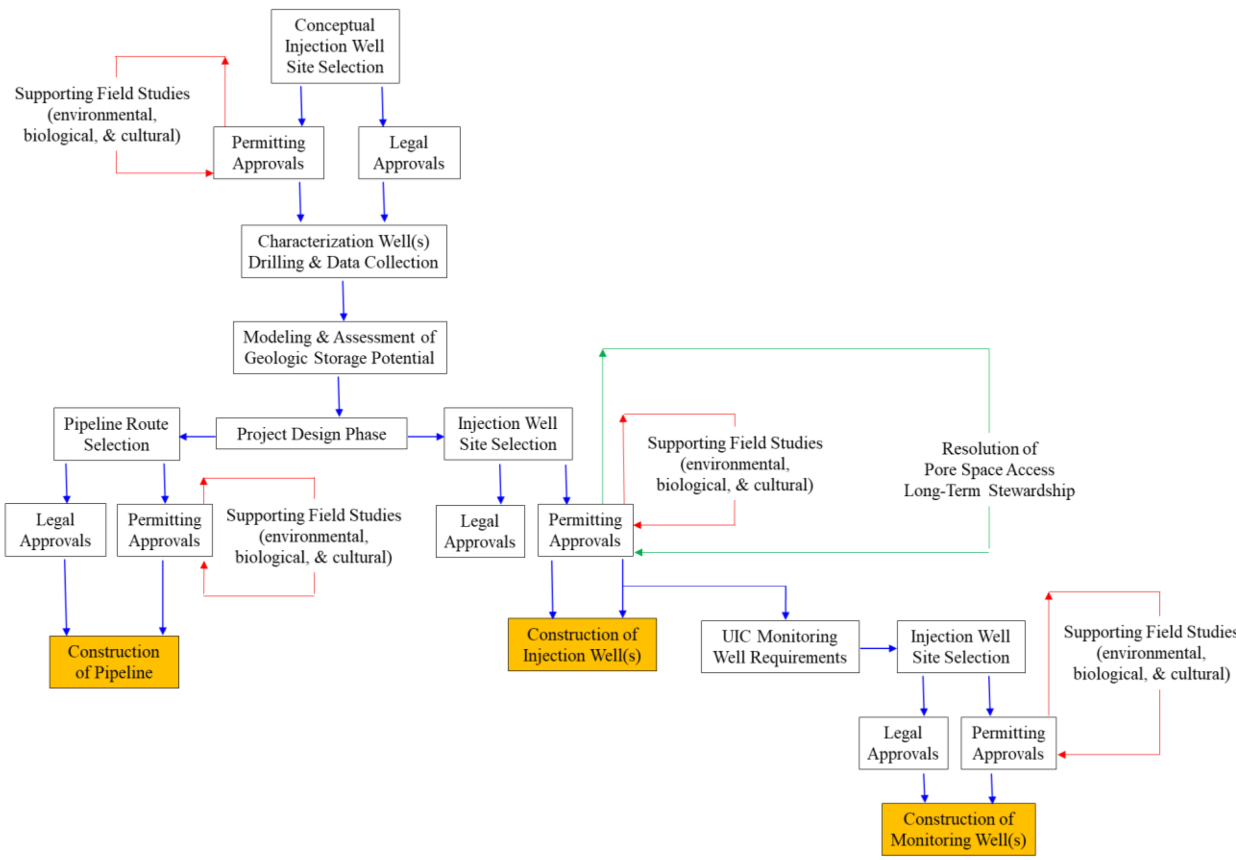
**A. Timing for state implementation plan development and approval is not sufficient to implement compliance strategies by 2030**

The timeline established in the proposed rule is not realistic and does not allow for making financially responsible compliance decisions. As drafted, the proposed rule requires existing coal-fired steam generating units to begin complying with their applicable emission limitation on January 1, 2030. For a coal-fired unit to operate beyond 2040, CCS with a 90% capture rate must be installed and operating by January 1, 2030. If EPA issues a final regulation in June of 2024, individual states will need to develop and submit their implementation plans to EPA by June of 2026. After submittal of the implementation plans in 2026, EPA will need to review and approve these plans, enabling them to become federally enforceable. In a June 14, 2021, report by the EPA Office of Inspector General, it was stated that as of January 1, 2021, approximately 39 percent of the 903 active SIP submittals awaiting EPA action were considered backlogged.[32] For purposes of the report, a SIP submittal is considered backlogged when it is not acted upon by the EPA with 12 months from the date of the completeness determination. Sources are not likely to make a compliance decision prior to knowing whether the plan will be approvable by EPA. It would be a very poor and irresponsible financial decision to make these choices prior to approval of the plans by EPA. Accordingly, it's not out of the question that sources would have less than 3 years to

[32] https://www.epa.gov/sites/default/files/2021-06/documents/_epaoig_20210614-21-e-0163__0.pdf

implement and begin operation of compliance choices made under this rule. This timeline is not achievable. These units will simply not be able to install the technology needed to meet the regulatory requirements for medium- or long-term retirement units by 2030.

Considering only the option of installing CCS for example, the short timelines presented by the proposal are simply not achievable. The flow diagram below presents an overview of just the non-capture aspects of CCS that take significant time, investment, and investigation prior to being developed and made operational. Most likely, these steps would require at least 2-3 years to complete.




## B. Timing for state implementation plan development does not allow for necessary technology and infrastructure development

If the proposed rule is finalized in 2024 and state implementation plans are required by 2026, there is insufficient time for development of the technologies proposed. In the case of CCS, companies cannot make a compliance commitment based on construction of pipeline infrastructure that does not exist. The development of necessary $CO_2$ and hydrogen pipeline infrastructure will likely still be in the design and permitting stages when companies would be required to make a compliance choice. Companies can't make a compliance decision today that depends on the development of infrastructure that is completely out of their hands and won't be available for many years, not to mention the well-established precedent in the US of pipeline projects not being completed (e.g., Mountain Valley). A similar situation presents itself with the development of hydrogen production and storage; and hydrogen-fired combustion turbine development.

**12. EPA should harmonize the compliance timelines and retirement options across all pending environmental rulemakings applicable to the existing fossil-based electric generation fleet.**

EPA should harmonize the compliance timelines and requirements across all the pending environmental rulemakings applicable to the existing fossil-based electric generation fleet. Such a comprehensive approach would allow for more holistic compliance strategies to be developed that will minimize the cost to customers, ensure the reliability of the electric grid, and support a more orderly transition from fossil generation to other generation resources. The EPA rulemakings to align include the Coal Combustion Residuals (CCR) rules, proposed Effluent Limitation Guidelines (ELG), proposed Mercury and Air Toxics Standards (MATS) rule, proposed regional haze requirements, the Good Neighbor Rule, and proposed GHG regulations under Clean Air Act, Section 111. To highlight the need for harmonization, consider the following recent retirement options presented in various EPA rulemakings:

- 2020 CCR Rule Revision: Option to retire by 10/17/2023 or 10/17/2028
- 2020 ELG Rule Revision: Option to retire by 12/31/28
- 2023 ELG Rule Proposal: Option to retire by 12/31/32
- 2023 Section 111(d) Proposal: Options to retire by 2032, 2035, or 2040

Further complicating compliance decisions are the staggered compliance dates for each:

- 2020 CCR Rule Revision: Comply no later than 10/15/23
- 2020 ELG Rule Revision: Comply no later than 12/31/25
- 2023 MATS Proposal: Comply ~ 2027 (three years after Rule finalized)
- 2023 ELG Rule Proposal: Comply no later than 12/31/29
- 2023 Section 111(d) Proposal: Comply no later than 12/31/29

Such a wide spectrum of compliance and retirement options creates significant challenges to developing and seeking approval for implementation strategies that must balance customer costs, reliability, and near- and long-term need for generation resources.

13. **Miscellaneous Considerations**

**A. Emission standards must account for source variability**

Any emission rate standard (e.g., lbs $CO_2$/MWh gross) that is finalized under the Section 111 regulation (e.g., phase one standard), must be set at a level that considers the variability in source operation. As the electric generation industry transforms, it will become more common for fossil fuel fired units to cycle frequently. More frequent startups and shutdowns result in periods in which the unit is being operated at reduced efficiency and a higher emissions rate. Any emissions rate finalized as a standard must consider these fluctuations and utilize an averaging rate of at least 12 months to "smooth" out the varying operating modes and fluctuating emission rate.

**B. Clarification of definitions in proposed regulation 40 CFR 60 Subpart UUUUb existing and modified units**

The definitions for "coal-fired steam generating unit" and "natural gas-fired steam generating unit" included in the proposed regulation for existing and modified units (40 CFR 60 Subpart UUUUb) appear to be inconsistent with one another and a clarification should be considered. The definitions seem to indicate that if a fossil fuel-fired electric utility steam generating unit is not a coal-fired or oil-fired steam generating unit and that it burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, **and** that no longer retains the capability to fire coal after December 31, 2029, then it would be considered an existing natural gas-fired steam generating unit for purposes of the rule. However, an inconsistency arises when you consider the language proposed for coal-fired steam generating units during a situation when a unit is being converted from coal-fired to natural gas-fired. Under the definition for coal-fired steam generating unit, if coal is burned for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, **or** it retains the capability to fire coal after December 31, 2029, then it would be considered an existing coal-fired steam generating unit for purposes of this rule. [emphasis added]

Consider a situation in which a coal-fired unit is operated in January of 2027 and then removed from service for a natural gas conversion project. Obviously, if the unit returns to service prior to January 1, 2030, as a natural gas fired unit and is no longer capable of burning coal, then it should be considered an existing natural gas fired steam generating unit. However, because the unit combusted coal during the first month of 2027, then the definition for coal fired steam generating unit would also appear to apply (albeit incorrectly).

# APPENDIX A: AEP Comments on Prior Section 111 Proposals

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May 8, 2014

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
ATTN: Docket ID No. EPA-HQ-OAR-2013-0495

Re: *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*
Docket ID No. EPA-HQ-OAR-2013-0495

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed standard of performance (NSPS) for greenhouse gas (GHG) emissions from new electric generating units (EGUs) under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), the Electric Power Research Institute (EPRI), West Virginia Chamber of Commerce, and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

John M. McManus

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Mr. Christian Fellner, U.S. EPA (by email)
Dr. Nick Hutson, U.S. EPA (by email)
Mr. Peter Tsirigotis, U.S. EPA (by email)
Dr. Robert Wayland, U.S. EPA (by email)

Executive Summary

I. AEP is Uniquely Positioned to Provide Detailed Comments on GHG Related Issues

II. EPA Has Not Complied with the Statutory Requirements Under Section 111 of the Clean Air Act that Apply to the Proposed Rule

A. EPA Must Make a Specific Endangerment Finding to Support Regulation of GHG Emissions from Fossil Fuel-Fired Electric Generating Units

B. EPA Cannot Rely on Carbon Capture and Storage Without Listing a New Source Category and Redefining the "Affected Facility" to Include Sequestration Facilities

C. EPA's BSER Evaluation and Determination is Inconsistent with Prior EPA Studies of Available Control Technologies for the Steam Electric Generating Source Category

D. EPA's Chosen Standard Violates Section 111(b)(5) of the Clean Air Act, Which Prohibits EPA From Requiring A Particular Control Technology to Comply With the NSPS

E. EPA Must Clearly Exclude Modified or Reconstructed Facilities from the Proposal

III. EPA Has Not Effectively Integrated the Operation of the Proposed Standard with the PSD Program

IV. EPA Is Barred From Considering Federally Assisted Demonstration Projects When Setting Performance Standards Under Section 111 of the Clean Air Act

A. Section 48A(g) Clearly Bars EPA From Relying On CCS Projects to Which Section 48A Tax Credits Have Been Allocated

1. The prohibition applies to any project for which the IRS has allocated the tax credit under Section 48A

2. The Section 48A(g) prohibition applies to all technology and levels of emission reduction achieved at the facility, regardless of whether the technology was the basis for the tax credit

B. Section 402(i) Prohibits EPA From Relying On Federally Subsidized Demonstration Projects Given The Lack Of Supporting Documentation To Conclude That CCS Is "Adequately Demonstrated"

1. EPA must have sufficient information from non-subsidized facilities to conclude CCS is demonstrated before relying on information from facilities that have received federal assistance

2. There is insufficient information in the record to allow EPA to rely on subsidized projects for its BSER determination

C. EPAct05 Funding For CCS Demonstration Projects Represents Congressional Judgment That This Technology Is Not Yet Adequately Demonstrated

V. Underlying Policy Goals Must Not Influence EPA's Analysis and Determination of the BSER for Fossil-Fuel Fired Electric Generating Units

VI. Federal Agencies May Not Infringe or Override Traditional State Sovereign Powers

VII. EPA Has Failed to Demonstrate that Any Increase in Title V Fees is Warranted

VIII. Partial CCS is Not the BSER for Fossil Fuel-Fired Boilers and IGCC Units

- A. EPA's "best judgment" fails to demonstrate that CCS is the BSER
- B. EPA has misinterpreted the realities and prospects of CCS development
- C. Technical feasibility is not the same as adequately demonstrated
- D. EPA's assessment of CCS is inconsistent with other EPA actions
- E. EPA's technical feasibility evaluation fails to demonstrate that CCS is the BSER
    1. EPA's literature review does not demonstrate that CCS is the BSER
        - a. Review of 2010 Interagency Task Force on CCS Report
        - b. Review of Pacific Northwest National Laboratory Report: An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009
        - c. Review of 2011 DOE/NETL Report: "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture"
    2. The project examples identified by EPA do not demonstrate that CCS is technically feasible or adequately demonstrated
    3. EPA has misinterpreted the experiences of other industries in evaluating the technical feasibility of CCS for fossil generation sources
- F. EPA's cost analysis fails to demonstrate that CCS is the BSER
    1. EPA's cost analysis is flawed due to an incorrect assumption that CCS development has advanced beyond first-of-a-kind technologies
    2. EPA's cost analysis is flawed due to a narrow review of available information and a failure to consider the cost of actual projects
    3. The experience of recent projects and findings of major studies demonstrate that EPA's cost analysis is flawed and that CCS is not the BSER
- G. EPA's evaluation of emission reductions fails to demonstrate that CCS is the BSER
- H. EPA fails to demonstrate that technology advancement will result from selecting CCS as the BSER

IX. Other Considerations Demonstrate that Partial Capture CCS is not the BSER

- A. AEP's CCS Program demonstrates that CCS is not the BSER
- B. Numerous Public and Private Efforts demonstrate that CCS is not the BSER
- C. Practical development considerations demonstrate that CCS is not the BSER
    1. CCS is not just another control technology

2. The cost of commercial-scale CCS remains a significant unknown
3. The energy required to power CCS systems is large and represents a significant development challenge
4. Integration of CCS and coal-based generation technologies introduces unique development challenges
5. Undeveloped regulatory and legal considerations may alone prohibit the development and adequate demonstration of CCS projects
    a. EPA has ignored property rights issues that are barriers to the adequate demonstration and development of CCS
    b. EPA has ignored long-term stewardship and liability issues, which are barriers to the adequate demonstration and development of CCS
    c. The EPA Class VI UIC permitting process and requirements introduce uncertainties that are a barrier to the adequate demonstration and development of CCS
    d. EPA ignores interstate and comingling issues that are barriers to the adequate demonstration and development of CCS
    e. Uncertainties regarding the applicability of RCRA regulations remain a barrier to CCS development
6. Geologic storage may be the greatest challenge to the adequate demonstration and development of CCS
7. $CO_2$ pipeline development presents challenges to the adequate demonstration and development of CCS
8. Enhanced oil recovery offers no guarantee as being available or willing to support $CO_2$ capture processes from coal-based generating units
9. Extensive permitting requirements introduces significant schedule and financial challenges to the development of CCS technologies

D. EPA's rationale for eliminating full capture CCS as the BSER is equally applicable to partial capture CCS

E. EPA's rationale for eliminating CCS as the BSER for the natural gas combustion turbine source category is equally applicable to CCS for fossil fuel-fired boilers and IGCC units

F. EPA's BSER determination is flawed because it does not consider all source types within the source category

X. Highly Efficient Generating Technologies are the BSER for Fossil-Fuel Fired Boilers and IGCC Units

A. EPA has not objectively evaluated highly efficient generation technologies and has prematurely eliminated this option as the BSER.

B. Highly efficient generating technologies are technically feasible

C. Highly efficient generating technologies are cost effective

D. Highly efficient generating technologies provide meaningful emission reductions, and have less overall environmental impacts compared to CCS systems

1. EPA incorrectly downplays and dismisses the emission reductions that may be achieved by highly efficient generating technologies
2. The development of highly efficient generation technologies continues to provide meaningful emission reductions
3. A BSER determination based on high efficient generation technologies would produce significant emission reductions
4. Highly efficient generation technologies provide greater overall environmental benefits compared to CCS technologies

E. Determining highly efficient generating technologies are the BSER would promote technology development

F. EPA should establish an NSPS subcategory that is specific to IGCC as these processes are fundamentally different from other coal generation technologies

1. IGCC technology is not a one-size-fits-all process design
2. An NSPS subcategory specific to IGCC should be established to address the unique operating conditions associated with these processes

G. EPA has incorrectly assessed the performance capabilities of new coal-based generating technologies that are designed without CCS

H. The BSER determination for fossil fuel-fired boilers and IGCC units must be based on highly efficient generating technologies

XI. Flaws in the Regulatory Impact Analysis and Supporting Economic Analyses

A. Cost Analysis

B. Levelized Cost Analysis

C. IPM Modeling

D. Benefit Analysis

E. Social Cost of Carbon

F. Climate Uncertainty Adder

**Executive Summary:**

Overview

AEP is uniquely positioned to offer detailed comments based on its recent construction and operation of projects that have set new standards for the performance of advanced coal-based generation technologies and that have pioneered efforts to validate carbon capture and storage (CCS) technology. While others can comment on the capabilities of these technologies based on high-level studies, conceptual designs, and generic development timelines of potential projects, AEP offers meaningful insight as a result of hands-on experience, and thus, respectfully requests that these comments receive careful consideration.

EPA considered two paths to determine a standard of performance for greenhouse gas (GHG) emissions from new fossil fuel-fired electric generating units: (1) highly efficient generation technologies and other efficiency measures, and (2) CCS technologies. However, rather than conducting a holistic, objective evaluation of these technologies and considering an appropriate balance of economic, environmental, and energy requirements, EPA simply reworked the structure of its 2012 proposal using information from very limited resources, and applied a double-standard to fossil fuel fired steam electric generating units (EGUs) and natural gas combustion turbine generating units. The outcome is a standard that has never been achieved at fossil fuel-fired-EGU based on a required control technology that has never been demonstrated, which effectively bans the development of new coal-based electric generation and creates an illegitimate predicate for regulating GHGs from existing sources. In fact, EPA notes the proposed rule will result in "negligible $CO_2$ emission changes...[or] quantified benefits."

For the legal and technical reasons present below, EPA should withdraw the proposal and perform an objective and comprehensive evaluation of the best systems of emission reductions (BSER). Such an evaluation will quickly reveal that CCS technologies have not been adequately demonstrated, and that the operating experience of high efficiency generation technologies must be the basis for proposing separate standards for fossil fuel-fired EGUs and for natural gas combustion turbines.

Summary of Legal Comments:

Section 111(b) of the Clean Air Act sets forth the fundamental framework for establishing technology-based standards that all new sources in a particular listed category must meet. The proposed standard does not comply with these statutory requirements because it:

- does not contain an adequate endangerment finding;
- assumes that effective sequestration of $CO_2$ will occur, but establishes no enforceable standards for those operations;
- proposes standards that do not reflect the degree of emission limitation achievable through application of the best system of emission reduction that has been adequately demonstrated (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements);
- is inconsistent with other information issued by the Administrator regarding the development of emission control technologies for the relevant source categories;
- requires the use of one, and only one, particular technological system, (CCS); and
- fails to account for the varied capacity for $CO_2$ transport and sequestration in different parts of the country (thereby giving certain states a competitive advantage).

In addition, the final rule must:

- address ambiguities on the applicability of the standards to modified or reconstructed sources, including clear language to exclude those sources;
- clearly indicate that the standards will not represent the floor in future BACT determinations for modified sources under the PSD program, and assure that the GHG tailoring thresholds operate effectively to prevent applicability to minor sources; and
- not intrude on the retained authority of the States for regulating electricity production as no federal statute, including the Clean Air Act, provides EPA with authority to preempt state decisions regarding the need for, location of, design of, services provided by, or rates to be charged to recover the costs of electricity generation.

A glaring deficiency of the proposed rule is the lack of requirements for successful short-term or permanent sequestration, where the reporting programs relied upon do not:

- currently apply to enhanced oil recovery (EOR) operations, the primary location where EPA expects all of the future sequestration of $CO_2$ from power plants to occur, because those wells are subject to alternative requirements under 40 CFR part 98 subpart UU;
- account for any losses that may occur during transportation to the EOR or other sequestration operation;
- impose any requirement to successfully sequester all or any portion of the $CO_2$ or other gases received, but only to attempt to estimate the amount that may have been successfully sequestered; and
- detail how EOR or CCS operators can account for commingled streams of anthropogenic and naturally produced $CO_2$, or streams of commingled $CO_2$ from multiple generators.

Summary of Comments Related to CCS Technologies:

CCS technology has never been constructed or operated at a commercial-scale on any fossil fuel-fired electric generating unit. Such applications face significant, wide-ranging, and unique development challenges that by many expert accounts are at least a decade away from being addressed, even under the most ambitious of development programs. At the highest levels of evaluation, the magnitude of these challenges quickly discount CCS as a viable candidate for determining the proposed NSPS. Any detailed, objective evaluation of these widely recognized technical, financial, regulatory, and legal concerns, and the actual experiences of proposed projects only reinforces the dismissal of CCS. Unfortunately, EPA concludes differently and relies upon an analysis that is fatally flawed due to:

- a series of premature, inaccurate conclusions on the development, demonstration, and performance of advanced generation and CCS technologies;
- minimal consideration and an abrupt dismissal of widely-acknowledged barriers to CCS becoming a technically feasible and adequately demonstrated control option;
- an inadequate consideration of the lessons learned from actual projects and the conclusions reached by major public and private assessments of CCS development;
- an inconsistent use of criteria to evaluate CCS for coal-based generation compared to criteria applied to other technologies within this proposal and other rulemakings;
- a failure to consider the true cost or the energy or environmental impacts of using CCS;
- an inadequate evaluation of the impacts to all sources within the source category; and
- use of underlying energy policy goals that do not allow for an objective evaluation of best system of emission reductions in accordance with the Clean Air Act.

EPA references 25 projects to determine that CCS has been adequately demonstrated. None of these projects, independently or collectively, is sufficient to make such a determination. Only two projects are actively undergoing construction. The remaining projects have only been proposed and are either not commercial-scale in size, or are associated with other industries. None have demonstrated or achieved the proposed standard, none are regulated to achieve a specific $CO_2$ limit, and to the extent operation of the CCS process is required, it is only for a specified demonstration period. Also, the key projects that EPA relies upon in the proposed rule are receiving financial assistance through the Energy Policy Act of 2005, which expressly prohibits the agency from considering them in the proposed rule. The consideration of these projects that are receiving financial assistance has the effect of eviscerating EPA's already meager record in support of its determination that CCS is adequately demonstrated, and further underscores the irrefutable conclusion that EPA lacks the necessary supporting evidence to determine that CCS is adequately demonstrated at this time.

EPA's analysis of CCS costs produces unreliable conclusions that are not supported by the experience of actual projects or the view of public and private entities with broader background and experience in technology development and cost estimation. EPA's cost analysis is fatally flawed due to a(n):

- incorrect assessment of the development status of CCS, which results in using cost estimates for yet-to-be realized more mature $n^{th}$-of-a-kind ("NOAK") type technologies, rather than initial first-of-a-kind ("FOAK") technologies;
- narrow reliance on two reports that are based on dated vendor supplied conceptual designs for CCS and IGCC technologies that have **never** been constructed or proven;
- failure to consider **any** of the costs and lessons learned from actual CCS related projects that have been constructed or that are actively being developed; and a
- failure to consider more recent and relevant studies of the cost of advanced coal-based generation and CCS technologies.

Based on these flawed assumptions, EPA concluded that the addition of CCS to new coal-fired generating units would increase the cost of electricity by 40-60% for full capture (90%) and by 12-20% for partial capture (~65%) systems. In contrast, active full- and partial-CCS projects are experiencing significant CCS-related cost escalations that approach 80%. These cost escalations are consistent with projections from other experts for related CCS systems, including Deputy Assistant Secretary of Energy Dr. Julio Friedmann who testified to an increase of 70-80%, the Global CCS Institute which reported an increase of 61-76%, and the DOE/NETL CCS Roadmap that estimates increases of up to 80%. It is clear that EPA's cost assessment misses the mark by a very wide margin. EPA eliminated full capture CCS from consideration solely due to costs (a 40-60% increase). If the 40-60% increase was sufficient to eliminate full capture, then the 80+% increase experienced by active projects and estimated by DOE and others is more than sufficient to eliminate partial capture CCS as well.

EPA also ignores the breadth of CCS development barriers related to equally significant technical, cost, and legal challenges for $CO_2$ *transport* and *storage* systems. The legal and regulatory uncertainties related to geologic storage include issues related to property rights, pore space ownership and acquisition, long-term stewardship and liabilities, as well as unknown injection well permitting requirements. A recent survey of all 50 states found that most are not well prepared to accommodate CCS projects, and are not proactively preparing. Another barrier to development barrier are the complex technical and financial uncertainties for geologic storage.

Summary of Comments Related to Highly Efficient Generation Technologies:

EPA's analysis of highly efficient generating technologies is woefully inadequate and has the strong appearance of being, at best, a hastily prepared and clumsily executed box-checking exercise that:

- does not "provid[e] the EPA greater assurance that it is basing its judgment on the best available, well-vetted science;"
- does not "address the scientific issues that the Administrator must examine;"
- does not "represent the current state of knowledge on the key elements;" and
- does not attempt to "comprehensively cover [or] obtain the majority conclusions from the body of scientific literature."

For example, EPA's evaluation of highly efficient technologies made

- no attempt to define highly efficient technologies;
- no attempt to understand or articulate the key variables that impact efficiency;
- no attempt to assess the prospects of developing solutions to reduce the impacts from these key variables on unit efficiency;
- no attempt to identify or assess the operation of highly efficient generation technologies domestically or internationally as the agency attempted with CCS;
- no attempt to quantify the potential emission reductions associated with the use of highly efficient generation technologies; and
- no attempt to assess the overall environmental benefits of highly efficient generation technologies compared to CCS technologies.

EPA's entire evaluation of highly efficient generation technologies is <u>less than one page</u> of the 90 page Federal Register version of the proposed rule. The record's lack of any serious evaluation of highly efficient generating technologies is even more surprising because the agency has evaluated such technologies in depth at least three times[1] in recent years in reports that (a) examine site-specific drivers that impact unit efficiency; (b) assess design opportunities for efficiency gains, including ultra-supercritical technologies; and (c) review specific domestic and international projects that are utilizing and advancing the development of higher efficient coal generation technologies. Alarmingly, none of this extensive information was utilized or even referenced in the proposed rule.

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[1] USEPA Reports: "*PSD and Title V Permitting Guidance for Greenhouse Gases*" (Mar 2011); "*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units*" (Oct 2010); "*Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies*" (Jul 2006);

Recommendations:

EPA should withdraw the proposed rule and perform a fair, objective, and comprehensive evaluation of the best systems of emission reductions. Such an evaluation will quickly reveal that CCS technologies have not been adequately demonstrated and that the operating experience of highly efficient generation technologies is the only basis for the development of separate standards for fossil fuel-fired steam EGUs and for natural gas combustion turbines.

In evaluating highly efficient generation technologies, EPA should include a detailed evaluation of unit operating data that are readily available in databases maintained by the agency. In addition, the demonstrated performance of international efforts and current research and development programs should be considered by EPA so that the current and long-term capabilities of highly efficient generating technologies are more accurately quantified. From these assessments, informed conclusions can be made regarding performance differences due to generation technology or fuel characteristics, which would then drive decisions regarding the appropriate emission rates and subcategories that represent the best system(s) of emission reduction. EPA has performed such evaluations for other agency efforts. Building off of these efforts would enable the agency to more thoroughly evaluate these options. The end result will be technically proven and legally acceptable proposed standards that are premised on the use of highly efficient generating technologies and that are structured with at least the following subcategories: (i) non-IGCC coal-based generating units; (ii) IGCC generating units; and (iii) natural gas-fired boiler generating units.

# I. AEP is Uniquely Positioned to Provide Detailed Comments on GHG Related Issues

AEP is uniquely positioned to offer detailed comments on the proposed rule based on its recent construction and operation of projects that have set new standards for the performance of advanced coal-based generation technologies and that have pioneered efforts to validate carbon capture and sequestration (CCS) at an operating coal-based generating unit. These efforts include the following:

- **Mountaineer Plant CCS Project:** The ***world's first*** fully integrated CCS project at an existing coal-fired electric generating unit. From 2009 to 2011, AEP successfully operated a *validation-scale* demonstration project that captured over 90% of the $CO_2$ from a small slip stream (1.5%) of flue gas and permanently sequestered more than 37,000 tons in geologic formations over 7,000 feet below the plant surface. Separately, front-end engineering and design was completed for second project that would have advanced the technology to a commercial-scale. Although the commercial-scale project was discontinued, significant knowledge was gained on the practical challenges that remain unresolved.[2] AEP continues post-closure monitoring of the sequestered $CO_2$ at the Mountaineer Plant under the terms of the first underground injection permit issued for a sequestration operation in West Virginia.

- **John W. Turk, Jr. Coal Power Plant:** In 2012, AEP commissioned the ***first ultra-supercritical*** power plant in the U.S. The design of the unit has set new standards for the efficiency and environmental performance of coal-based power generation.

- **IGCC Development:** From 2004 to 2008, AEP actively developed multiple IGCC projects, including preliminary site studies, permitting, and the completion of front-end engineering and design. Although these projects were not developed, the lessons learned provide unique insight on the challenges and opportunities for IGCC projects.

While others can comment on the capabilities of advanced coal generation and CCS technologies based only on high-level studies, conceptual designs, and generic development timelines of potential projects, AEP is able to offer meaningful insight based on hands-on experience. Therefore, AEP respectfully requests that these comments receive careful consideration in developing a final GHG NSPS.

The success of these recent projects continues over 100 years of leadership and innovation in the generation, transmission, and distribution of electricity. AEP's contributions include many first-in-the-world accomplishments that have set new standards for combustion efficiencies, emissions control, and system performance. Examples include the first reheat

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[2] The Mountaineer CCS validation project capture *did not* constitute a commercial demonstration and *should not* be represented as proof that commercial-scale CCS technology is technically feasible or adequately demonstrated.

generating coal unit (1924); the first heat rate below 10,000 Btu/kWh at a coal plant (1950); the first natural-draft, hyperbolic cooling tower in the Western Hemisphere (1963); the first combined-cycle operation of a pressurized, fluidized bed combustion plant in the U.S. (1990); and the first venting of flue gas through a natural-draft cooling tower in the U.S. (2012).

AEP also has a long history of proactive involvement in stewardship activities. In the 1940's, AEP was involved in re-forestation programs, including specific efforts to convert portions of its large land holdings from agricultural and mining activities to conservation activities, including use as potential carbon sinks. In 1995, AEP committed to plant over 15 million trees over a five-year period as part of its participation in the U.S. Department of Energy's Climate Challenge Project. AEP has also pioneered international and domestic efforts to preserve existing forested lands, increase the number of actively managed forested acres in state and federal preserves and wildlife areas, and to create newly forested areas where the sequestration potential of good forest management projects could be studied to help develop the tools needed to quantify creditable increases in the sequestration of $CO_2$.

AEP has been a leader in the development of climate change policies and regulatory development as well. For example, AEP played a major role in supporting Congressional action to establish comprehensive climate change legislation that can use the power of markets to capture additional reductions in GHG emissions. AEP supported efforts in 2009 to design common-sense climate change legislation that would allow the U.S. to achieve significant progress in reducing GHG emissions without sacrificing the opportunity to remain economically secure and retain domestic jobs. AEP was a founding member of the Chicago Climate Exchange, the first voluntary GHG credit trading system in the U.S., where AEP established and met goals to reduce or offset GHG emissions by an annual target of 6% (compared to emission levels during 1998-2001) by 2010. AEP has voluntarily established a further goal of reducing or offsetting its GHG emissions by 10% (compared to 2010 levels) by 2020. In addition, AEP has participated in EPA's Climate Leaders Program, earning recognition and awards for innovation and achievement. In 2006, the Carbon Disclosure Project named AEP to its Climate Leadership Index, placing AEP among 50 other international corporations whose strategic awareness of the risks and opportunities associated with carbon constraints and whose effective programs to reduce overall GHG emissions have earned similar distinctions.

Notwithstanding AEP's history of environmental conservation and support for federal GHG reduction efforts, AEP cannot support EPA's proposed GHG NSPS. As presented in the comments that follow, EPA's proposed rule is unlawful, based on incomplete and incorrect information, and would hinder the very efforts to develop clean coal technology that Congress, EPA, and AEP have worked so long and hard to advance. AEP is particularly concerned that the proposed rule will "freeze" CCS and advanced coal-fueled generation technology development at its current stage and hinder the kind of progress that would allow coal to continue to play a vital role in America's energy policy. For the legal and technical reasons presented below, EPA should withdraw the current proposal and perform an objective and holistic evaluation of options for the Best System of Emission Reduction (BSER) for fossil fuel-fired electric generating units and combustion turbines. Such an evaluation will reveal that CCS technology has not been adequately demonstrated and that highly efficient generation technologies represent the best balance of the environmental, economic, and energy considerations that must inform the selection of the BSER for fossil fuel-fired generating units.

## II. EPA Has Not Complied with the Statutory Requirements Under Section 111 of the Clean Air Act that Apply to the Proposed Rule

Section 111(b) sets forth the fundamental framework for establishing technology-based standards with which all new sources within a particular listed category must comply. Under Section 111 (b)(1)(A), the Administrator is required to publish a list of categories of sources that, "in [her] judgment...cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[3] For each listed category of sources, the Administrator is then required to establish federal standards of performance for new sources in the category.[4] The Administrator may distinguish among classes, types and sizes of sources in establishing those standards;[5] she must periodically issue information regarding pollution control techniques for those categories and air pollutants;[6] and she may not use her standard-setting authority to require the use of particular technologies.[7]

[3] 42 U.S.C. § 7411(b)(1)(A).
[4] 42 U.S.C. § 7411(b)(1)(B).
[5] 42 U.S.C. § 7411(b)(2).
[6] 42 U.S.C. § 7411(b)(3).
[7] 42 U.S.C. § 7411(b)(5).

The proposed standard does not comply with the statutory requirements of Section 111(b) for a number of reasons, including because it:

- does not contain an adequate endangerment finding,
- proposes standards that do not reflect the degree of emission limitation achievable through application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) has been adequately demonstrated,
- is inconsistent with other information issued by the Administrator regarding pollution control technologies for the relevant source categories,
- requires the use of one, and only one, particular technological system, and
- fails to account for the varied capacity for $CO_2$ transport and sequestration in different parts of the country (thereby giving certain states a competitive advantage).

### A. EPA Must Make a Specific Endangerment Finding to Support Regulation of GHG Emissions from Fossil Fuel-Fired Electric Generating Units

Section 111(b) clearly and specifically requires the Administrator to make a determination that the source category to be regulated causes or contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare, a determination that EPA erroneously claims has previously been made with respect to the source categories affected by the proposal in prior NSPS rulemakings, and with respect to the pollutant to be regulated in an unrelated finding made pursuant to Section 202 of the Clean Air Act. However, the source category to which the proposed new subpart TTTT standards would apply (and indeed the segments of the source categories to which the proposed standards under existing subparts Da and KKK would apply) is not the same one for which prior section 111(b)(1)(A) determinations have been made, and EPA has made no determinations under section 111(b)(1)(A) with respect to $CO_2$ emissions from new fossil fuel-fired electric generating units and combustion turbines. EPA does not dispute that no specific examination of the effects of $CO_2$ emissions from the source categories proposed to be regulated under Section 111 has been performed, but argues that it must merely demonstrate that there is a "rational basis" for regulating $CO_2$ emissions from these previously listed categories of sources.[8]

There is no question that EPA's prior determinations for the existing source categories under Subpart Da (electric utility steam generating units) and Subpart KKKK (stationary

[8] Proposed Rule: *Standards of Performance for Greenhouse Gas Emission from New Stationary Sources: Electric Utility Generating Units,* 79 *Fed. Reg*. 1454 (Jan. 8, 2014) (hereinafter "Proposed Rule").

combustion turbines) were not based on $CO_2$ emissions or their potential impacts, and did not apply to the defined universe of facilities EPA now proposes to regulate. The preamble to the final rule establishing subpart Da in 1979 merely referred to the finding made in general for electric utility steam generating units when the source category was first listed in 1971.[9] The entire cause-or-contribute finding for this initial listing is contained in a single sentence:

> "The Administrator, after evaluating available information, has determined that the following are categories of stationary sources which meet the above requirements [of "caus[ing] or contribut[ing] to the endangerment of public health or welfare"]: Contact sulfuric acid plants; *fossil fuel-fired steam generators of more than 250 million B.t.u. per hour heat input*; municipal incinerators of more than 2000 lbs. per hour refuse charging rate; nitric acid plants; and portland cement plants."[10]

At the time of the original finding, the statutory language in the 1970 version of the Act required the Administrator to list a category of sources "if [s]he determine[d] it may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare."[11] Today, the Act requires a determination that the source category "causes, or contributes significantly, to air pollution which may reasonably be anticipated to endanger public health or welfare."[12] No finding has ever been made based on the current statutory language for the universe of sources EPA now seeks to regulate based on their emissions of $CO_2$ and the effects such emissions may potentially have on the public health or welfare.

The next revision of the NSPS for EGUs was proposed on September 19, 1978, pursuant to the 1977 Clean Air Act Amendments. These proposed standards were to apply to "all electric utility steam generating units (1) capable of firing more than 73 MW (250 million Btu/per hour) heat input of fossil fuel (approximately 25 MW of electrical energy output) and (2) for which construction is commenced after September 18, 1978."[13] The proposal excluded from regulation parts of subpart D, including certain cogeneration and industrial steam electric generating units.[14] As noted above, no independent cause-or-contribute-significantly finding accompanied or preceded either the proposed or final creation of new subpart Da. The preamble to the proposed subpart Da merely noted that the Administrator had previously determined that "electric utility steam generating units" "contribute significantly to air pollution which causes or contributes to

[9] 44 *Fed. Reg*. 33,580, 33,611/3 (June 11, 1979), *citing* 36 *Fed. Reg*. 5931, March 31, 1971.
[10] 36 Fed. Reg. 5931, 5931 (emphasis added).
[11] Clean Air Amendments of 1970, Pub. L. 91-604, 84 Stat. 1676, 1683-84 (1970).
[12] 42 U.S.C §7411(b)(1)(A).
[13] 43 Fed. Reg. at 42,157.
[14] 43 Fed. Reg. at 42,157.

the endangerment of public health or welfare."[15] In addition, when subpart KKKK was proposed in 2005 and finalized in 2006, the Agency made no determination that this source category causes or contributes significantly to air pollution.[16]

Finally, EPA has not made a finding that the specific air contaminants it proposes to regulate from the specific source category it proposes to regulate may endanger public health and welfare. At the time of the original finding for steam electric generating units, the "air pollution" impacts were those associated primarily with air pollutants for which a national ambient air quality standard (NAAQS) had been established, and for which emission reductions would result in improvements of local air quality necessary for achievement of those NAAQS. Nothing in those findings is relevant to the question of whether yet-to-be-built fossil fuel-fired electric generating units or combustion turbines will "cause or contribute significantly" to global concentrations of $CO_2$, which is known to cumulate and persist in the atmosphere. EPA has not defined what level of contribution is "significant" in this context, and none of its prior actions provides any intelligible principal from which a "significant" contribution could be distinguished from a "non-significant" contribution in the context of such a global pollutant. Nor has EPA established how to value reductions of such global pollutants, since there are no objective metrics (like the NAAQS) against which to assess the impact of any $CO_2$ emission reductions achieved through the proposed NSPS. Certainly, EPA's prior actions based on contributions of pollutants for which a NAAQS had been established are not a reasonable guide in the context of GHG emissions.

EPA asserts that it does not need to make a "pollutant-specific endangerment finding." But the language of Section 111(b)(1)(A) is substantially similar to the language in Section 202(a)(1), and the U.S. Supreme Court has interpreted Section 202(a)(1) to require a finding of endangerment that in turn "requires the agency to regulate emissions *of the deleterious pollutant*" that was the basis for the finding.[17] Section 111(b)(1)(A) should be read consistently with Section 202(a)(1) and the Supreme Court's past precedent because if EPA's rulemaking authority is not confined to only those pollutants that are the subject of its endangerment finding, then EPA has no statutory basis upon which to determine which pollutants should be regulated under Section 111. EPA has never regulated *all* pollutants emitted by a listed source category;

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[15] 43 Fed. Reg. at 42,173.
[16] *See* 70 Fed. Reg. 8314 (Feb. 18, 2005) (proposed rule); 71 Fed Reg. 38,482 (July 6, 2006) (final rule).
[17] *Massachusetts v. EPA*, 127 S.Ct. 1438, 1462 (2007). (emphasis added)

nor could it, consistent with the limitations on its rulemaking authority in Section 301(a). Therefore, EPA must make a specific finding that the emissions of a particular pollutant from a listed source category cause or contribute to air pollution that is reasonably anticipated to endanger public health and welfare prior to establishing standards under Section 111(b).

Moreover, since EPA assumes that its proposal for fossil fuel-fired electric generating units and combustion turbines will not result in any actual emission reduction benefits (unlike the mobile source standards proposed based on the 2009 Endangerment Finding), EPA's assertion that no specific finding is required amounts to a claim of unfettered discretion to promulgate a standard regardless of the amount of emissions from the source category, the efficacy of the standard in reducing those emissions, or the ultimate impacts of public health or welfare. Such unbounded discretion cannot legally be granted by Congress, as it represents a total abdication of the requirement that legislation provide specific boundaries for the exercise of any agency's discretion. Nor can an agency interpret its authorizing statute in such a broad manner.[18]

In sum, EPA has failed to make the required endangerment and cause-or-contribute findings for $CO_2$ emissions from the source category included in this proposal. EPA's obligation is plain under the statute. Whether EPA creates a new source category, as proposed with Subpart TTTTT, or expands the pollutants regulated for an existing source category, the agency must *first* make an endangerment finding for that source category *and* the pollutants alleged to impact public health and welfare, *before* promulgating standards for emissions from that source category. Given the exclusions proposed for either the existing Subpart Da and KKKK, or the new subpart TTTT, the source category is not the same one for which prior determinations has been made. Even if EPA proceeds to regulate based on the existing source categories (which, as argued below, is ineffective and therefore unlawful), EPA must *first* make a specific endangerment finding for $CO_2$ emissions from these source categories. Given the paucity of the prior endangerment findings, the lack of any prior cause-or-contribute findings for a pollutant like $CO_2$, and the need to fully evaluate the "sources" that should be included in the source category to be regulated, as discussed below, EPA must undertake a separate determination under the plain language of the statute, and cannot "interpret" this requirement out of the statute.

EPA's assertion that all that is required is a "rational basis" to regulate $CO_2$ emissions from any previously listed stationary source category, and that the prior listing determination and

[18] *American Trucking Assoc., Inc. v. EPA,* 175 F.3d 1027, 1034 (D.C. Cir. 1999).

the 2009 Endangerment Finding issued to support its motor vehicle regulations under Title II of the Clean Air Act supply that "rational basis," finds no support in the language of Section 111, and is inconsistent with EPA's prior statements about the Endangerment Finding. EPA advised Congress in 2011 that the 2009 Endangerment Finding "did not require or implicate an assessment of which stationary source categories warrant GHG limits under the NSPS program."[19] And EPA's purported "rational basis" disappears because EPA admits that the proposal will do nothing to reduce $CO_2$ emissions, as no new coal-fired units will be built while the proposal is in effect. To hold otherwise would allow EPA to fashion regulations whenever it chooses, even if the regulated sources are minor contributors, and the regulations produce no emission reductions. Such unbridled discretion is totally inconsistent with the statutory command in Section 301(a)(1) authorizing the Administrator only to "prescribe such regulations as are necessary to carry out [her] functions under this Act,"[20] and the instruction in Section 111(b)(1)(B) that the Administrator "need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information in the efficacy of such standard."[21] EPA's proposal is intended to do nothing more than create an illegitimate predicate for regulating emissions of $CO_2$ from existing sources. Such action is not authorized by the Act.

### B. EPA Cannot Rely on Carbon Capture and Storage Without Listing a New Source Category and Redefining the "Affected Facility" to Include Sequestration Facilities

For new fossil fuel-fired EGUs, EPA's proposal is woefully incomplete, because EPA has not listed a source category that includes all of the affected facilities necessary to effectively control $CO_2$ emissions. EPA asserts that it is regulating the same source categories currently regulated under Subpart Da, but those sources do not include the $CO_2$ transport and sequestration or end use processes necessary to segregate the captured $CO_2$ emissions from the atmosphere. In an effort to avoid redefining the source category, EPA claims that it "is proposing to build from the existing GHG Reporting Program in 40 CFR part 98 to track that the captured $CO_2$ is geologically sequestered."[22] Specifically, EPA relies on subparts D, PP, and RR of 40 CFR part

[19] Letter from Gina McCarthy, EPA Assistant Administrator, to the Honorable Fred Upton, Chairman, U.S. House of Representatives Committee on Energy and Commerce, Responses to Questions 11 & 17a (Aug. 3, 2011).
[20] 42 U.S.C.§ 7601(a)(1).
[21] 42 U.S.C.§ 7411(b)(1)(B).
[22] Proposed Rule at 1482.

98 to provide a "transparent reporting and verification mechanism for EPA and the public"[23] which EPA assumes will demonstrate successful sequestration of the vast majority of $CO_2$ delivered to an EOR or other sequestration operation.

However, the programs that EPA "relies" on to demonstrate successful $CO_2$ sequestration do not:

- currently apply to enhanced oil recovery (EOR) operations, the primary location where EPA expects all of the future sequestration of $CO_2$ from power plants to occur, because those wells are subject to alternative requirements under 40 CFR part 98 subpart UU;
- account for any losses that may occur during transportation to the EOR or other sequestration operation;
- impose any requirement to successfully sequester all or any portion of the $CO_2$ or other gases received, but only attempt to estimate the amount that may have been successfully sequestered; and
- detail how EOR or CCS operators can account for commingled streams of anthropogenic and naturally produced $CO_2$, or streams of commingled $CO_2$ from multiple generators.

In developing the reporting programs for $CO_2$ injection, EPA unequivocally stated, "This rule does not require control of greenhouse gases, rather it requires only monitoring and reporting of greenhouse gases."[24] Without an effective method to establish an enforceable standard for sequestration, EPA's proposal to require capture and reporting of $CO_2$ emissions is simply ineffective. A standard that is ineffective and achieves nothing is inherently arbitrary.

The enforceability of EPA's standard is highly questionable when there are no requirements for successful sequestration, and when the agency is simply relying on a never-used and inadequately designed reporting tool. For EPA to actually develop and implement a standard based on CCS, a totally new category of sources must be listed that includes the sequestration facilities that are critical to real achievement of the standards. No such listing has been made, and EPA's standard therefore is fatally flawed. The proposed standard for fossil-fueled EGUs amounts to nothing more than a requirement to capture $CO_2$, with no effective limitations that assure its short-term or permanent sequestration.

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[23] Proposed Rule at 1483.
[24] 75 *Fed. Reg.* 75060 (Dec. 1, 2010).

### C. EPA's BSER Evaluation and Determination is Inconsistent with Prior EPA Studies of Available Control Technologies for the Steam Electric Generating Source Category

EPA's lack of any serious evaluation of highly efficient generating technologies is inconsistent with Section 111(b)(3), which requires EPA to issue and take into account information on technologies that could be applied to the specific source category for which an NSPS is being developed. The agency has evaluated technologies for $CO_2$ emission reductions in depth at least three times in recent years in the following reports:

- "PSD and Title V Permitting Guidance for Greenhouse Gases" (Mar 2011) U.S. EPA;
- "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units" (Oct. 2010) U.S. EPA; and
- "Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies" (July 2006) U.S. EPA.

Collectively, these EPA reports:

- examine site-specific drivers that impact unit efficiency;
- assess design opportunities for efficiency improvements;
- review ultra-supercritical boiler technologies; and
- identify and discuss specific domestic and international projects that are utilizing and advancing the development of higher efficient coal generation technologies.

In addition, the 2010 report states that EPA was developing a publicly-accessible database of greenhouse gas mitigation technologies. It was noted that the "database is a tool that provides information on both commercially available technologies, as well as emerging technologies that are being demonstrated at larger scales for commercial viability."[25] At least as of 2011, EPA was progressing on the development of the database and was actively presenting updates and discussing beta versions at various conferences.[26]

Alarmingly, none of this extensive information was utilized or even referenced in EPA's less than one page evaluation of highly efficient generation technologies. It is unclear why EPA completely ignored this information, as consideration of these reports and other related information would clearly indicate that highly efficient generation technologies are the BSER upon which a balanced NSPS could be based.

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[25] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA. (Oct 2010). p. 40

[26] www.epa.gov/air/caaac/pdfs/1_11_GMOD_CAAAC.pdf

### D. EPA's Chosen Standard Violates Section 111(b)(5) of the Clean Air Act, Which Prohibits EPA From Requiring A Particular Control Technology to Comply With the NSPS

The definition of a "standard of performance" under Section 111 requires that the Administrator perform three separate tasks:

(1) identify the best systems of emission reduction that have been adequately demonstrated;

(2) review the costs, non-air quality health and environmental impacts, and energy requirements of achieving various levels of emission reduction through the use of such technologies; and

(3) determine the emission limitation that is achievable through the use of the BSER without unreasonable costs, energy requirements, or other impacts.

The standard selected is then supposed to reflect the agency's informed judgment that "represents the best balance of economic, environmental, and energy considerations."[27] As is discussed in detail in the technical sections below, for coal-fired units, EPA has rejected all technologies except one, CCS, and has ignored the fact that this technology has never been operated at a commercial scale on a major electrical generating unit. EPA has not conducted any detailed analysis of the true costs or the energy or environmental impacts associated with the use of CCS. EPA has admitted that CCS cannot be readily employed in all regions of the country due to the lack of suitable sequestration opportunities. While the inability of large portions of a source category to employ specific technologies has previously led EPA to reject that technology as a basis for a performance standard, in this case EPA has deemed partial CCS to be the BSER and established a standard that cannot be met without it.[28]

Nor has EPA conducted any analysis to determine the achievability of its proposed standard for coal-fired units. Customarily, EPA has conducted rigorous analyses to establish "what every source can achieve" through the use of demonstrated technologies, by examining actual test data that are representative of the wide range of variables that affect the achievability of the a specific emission limitation.[29] No such analysis was undertaken here. In the absence of such analyses, EPA's proposal fails to satisfy the minimum statutory requirements and must be withdrawn.

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[27] *Sierra Club v. EPA,* 657 F.2d 298, 330 (D.C. Cir. 1981); *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

[28] 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005) (rejecting specific boiler designs and clean fuels as a basis for revised NOx standards because of the unavailability of these options for all source types within the category).

[29] *Sierra Club,* 657 F.2d at 377.

In limiting EPA's authority to establish an NSPS based on the use of specifically prescribed technology, Section 111(b)(5) of the Clean Air Act states:

> "*...nothing in this section shall be construed to require, or authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.*"[30]

Rather than comply with this statutory mandate, EPA's proposal is specifically designed to facilitate the development and require the use of one technology, and only one technology, CCS. Although EPA found that highly efficient generation technologies (including supercritical, ultra-supercritical and IGCC technologies) are "clearly technically feasible" and represent "little or no incremental cost" when developing a new source, the agency incorrectly rejected these alternatives as the BSER. Detailed comments on EPA's flawed assessment of CCS and highly efficient generating technologies are provided in the sections that follow.

The EPA proposal relies heavily on a very few number of proposed CCS projects – none of which have been constructed or operated – to attempt to justify that CCS is adequately demonstrated to be the BSER. However, as demonstrated below, the consideration of the technologies to be used or the emission reductions to be achieved by the key proposed CCS projects that EPA relies upon is expressly prohibited by the Energy Policy Act of 2005 (EPAct05).[31] All of the key proposed projects that EPA relies upon have received government funding and/or tax relief. The criteria for receipt of such funding or tax relief in the U.S. is based on a Congressional determination that clean coal technologies with advanced environmental performance, including CCS, were not commercially available or cost-effective. None of the demonstration projects has, to date, logged one hour of actual operating time. All of these facts demonstrate that EPA's reliance on these projects as proof that CCS is "adequately demonstrated" is fatally flawed.

EPA's flawed conclusion that CCS has been "adequately demonstrated" leads to a grossly insufficient consideration and premature dismissal of highly efficient generation technologies as a legitimate option as the BSER. As discussed in detail in the technical sections that follow below, EPA completely ignores domestic and international projects and research (some of which EPA has funded and evaluated in other studies) that have significantly advanced

[30] 42 U.S.C. §7411(b)(5).
[31] P.L. 109-58 (Aug. 8, 2005).

and accelerated the development of more efficient coal-based generation technologies. EPA fails to discuss the performance of ultra-supercritical plants, which are currently operating and show substantial promise. Leapfrogging past the efficiencies that can be gained in the generation process itself may discourage future advancement of these approaches, and leave significant untapped potential for GHG reduction unexplored. Instead, EPA has picked *one* technology, and one alone, that, if successfully developed, could potentially achieve the required reductions of its proposed standard. Section 111(b)(5) prohibits the selection of such a narrow standard, particularly where, as here, the "chosen technology" has not been adequately demonstrated, and is not widely available for use throughout the industry.

EPA's historic practice, as evidenced in *Sierra Club v. Costle*,[32] has been to moderate the NSPS standard so that multiple compliance options can be explored by new sources, and to assure broad availability of the measures necessary to meet the standard, regardless of geographic location. In that case, the D.C. Circuit endorsed EPA's *moderation* of the NSPS to allow for development of more cost-effective dry scrubbing techniques that were suitable for western low sulfur coals. It did not, as EPA argues in the preamble, allow the agency to impose a standard based on technologies never before demonstrated, or ignore the most significant costs imposed on regulated sources within the listed category. As discussed in detail below, highly efficient generating technologies are the BSER for all fossil fuel-fired units, based on any objective examination of the state of technological development, and an appropriate balance of economic, environmental, and energy requirements. Accordingly, EPA's proposal should be withdrawn, and a new proposal should be issued based on separate standards for various unit types, including subcategories for gas-, oil- and coal-fired steam generating units, and natural gas combustion turbines.

[32] *Sierra Club v. Costle*, 657 F.2d 298, 347 (D.C. Cir. 1981).

## E. EPA Must Clearly Exclude Modified or Reconstructed Facilities from the Proposal

EPA's discussion of the treatment of modified and reconstructed sources is confined to a few brief references in the proposal:

> "*We are not proposing standards for certain types of sources. These include new steam generating units and stationary combustion turbines that sell one-third or less of their potential output to the grid; new non-natural gas-fired stationary combustion turbines; existing sources undertaking modifications or reconstructions; or certain projects under development...*"[33]

Nothing in the regulatory text proposed by EPA clearly reflects this treatment. The applicability provisions of Subpart Da simply state:

> "*Your affected facility is subject to this section if construction commenced after* [January 8, 2014], *and the affected facility meets the conditions specified in paragraphs (a)(1) and (a)(2) of this section, except as specified in paragraph (b) of this section*."[34]

Paragraphs (a)(1) and (a)(2) establish the conditions that the facility must: (1) combust fossil fuel for more than 10 percent of the heat input over 3 consecutive calendar years; and (2) supply more than one-third of its potential electric output and more than 219,000 MWh for sale on an annual basis. Paragraph (b) contains exceptions for three specific facilities that are currently under development and have received preconstruction permits from state agencies. Nowhere is there any reflection of EPA's stated intent to apply this standard solely to "new" units, but not to "modified" or "reconstructed" units. The same flaws are present in the standard proposed as part of the alternative new subpart TTTT, which contains additional exclusions for municipal and solid waste combustors.

Section 111(a)(2) of the Clean Air Act defines a "new source" as

> *any stationary source, the construction or* ***modification*** *of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source*.[35]

The definitions in subparts A and Da of part 60 incorporate the definitions provided in the statute.[36] In addition, the definition of "commenced" in Subpart A of part 60, which is specifically listed as being applicable to subpart TTTT, provides that:

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[33] Proposed Rule at 1446.
[34] Proposed Rule at 1502.
[35] 42 U.S.C. § 7411(a)(2) (emphasis added).
[36] 40 CFR §§60.2 and 60.42Da.

> *"**Commenced** means, with respect to the definition of **new source** in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction **or modification** or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or **modification**."*[37]

Together, these provisions contain ambiguities that fail to clearly limit the applicability of the proposed standard to new sources, but not to modified or reconstructed sources. AEP supports the insertion of clear regulatory language that would clarify that the proposed standards for $CO_2$ do not apply to any modified or reconstructed sources. As EPA admits in the preamble, "our analysis for this proposed NSPS considers only the extent to which particular pollution control techniques are BSER for new units, and does not evaluate whether such techniques also qualify as BSER for modified or reconstructed sources under Part 60 or are otherwise achievable methods for reducing GHG emission from such sources considering economic, environmental, and energy impacts."[38]

In the absence of such an analysis, EPA cannot recommend a standard for any existing unit that is modified or reconstructed. Moreover, there are practical limitations at existing sources that clearly preclude CCS from being considered adequately demonstrated or achievable for existing sources, including limitations on available space at existing sites, lack of suitable sequestration opportunities, and the significant adverse non-air environmental and energy impacts associated with its implementation. AEP urges EPA to clearly exclude modified and reconstructed sources from the proposed and final standards through the addition of clear language in the applicability sections.

## III. EPA Has Not Effectively Integrated the Operation of the Proposed Standard with the PSD Program

The U.S. Supreme Court is considering whether EPA properly concluded that the issuance of mobile source standards under Section 202 of the Clean Air Act automatically triggered the regulation of GHG emissions from stationary sources under the Title V and Prevention of Significant Deterioration (PSD) permitting programs.[39] The outcome of that litigation is not yet known. However, if the provisions of the agency's GHG tailoring rule in its PSD permitting regulations are upheld, the regulatory language developed for this proposal must

[37] 40 CFR §60.2. (emphasis added)
[38] Proposed Rule at 1489.
[39] *UARG v. EPA*, No. 12-1146 and consolidated cases, *cert. granted* Oct. 15, 2013.

be supplemented to clearly reflect the agency's intent that these standards will not represent a "floor" in any future BACT determination for a modified source under the PSD program, and to assure that the GHG tailoring thresholds operate effectively to prevent application of the program to minor sources.

In discussing the interaction between the Section 111 standards being developed for fossil fuel-fired electric utility units and combustion turbines and the permitting requirements under the Prevention of Significant Deterioration (PSD) Program in Subchapter C of Title I of the Clean Air Act, the Proposed Rule states:

> "*Under this proposed NSPS, an affected facility is a new EGU. In this rule we are not proposing standards for modified or reconstructed sources. However, since both a new and existing power plant can add new EGUs to increase generating capacity, this NSPS will apply to both a new, greenfield EGU facility or an existing facility that adds EGU capacity by adding a new EGU that is an affected facility under this NSPS. While this latter scenario can be considered the modification of existing sources under PSD, this proposed NSPS will not apply to modified or reconstructed sources as those terms are defined under part 60. Thus, this NSPS would not establish a BACT floor for sources that are modifying an existing EGU, for example, by adding new steam tubes in an existing boiler or replacing blades in their existing combustion turbine with a more efficient design.*
>
> *Furthermore, our analysis for this proposed NSPS considers only the extent to which particular pollution control techniques are BSER for new units, and does not evaluate whether such techniques also qualify as BSER for modified or reconstructed sources under Part 60 or are otherwise achievable methods for reducing GHG emission from such sources considering economic, environmental, and energy impacts. Therefore, we do not believe that the content of this rule has any direct applicability on the determination of BACT for any part 60 modified or reconstructed sources obtaining a PSD permit*."[40]

As discussed, EPA has not effectively incorporated this intent in its crafting of the applicability provisions of the proposed rule, and its treatment of the interaction between Part 60 standards and the PSD permitting rules is equally flawed. Although the proposed rule discusses the inapplicability of the proposed standards to any modification or reconstruction of an existing unit, no changes are proposed to the definition of "best available control technology" (BACT) in the PSD regulations, or otherwise effectively constrain permitting authorities from applying these new standards as a "floor" for purposes of the BACT analysis.[41] Even though EPA "does

[40] Proposed Rule at 1489.
[41] Proposed Rule at 1488-1489.

not believe" that the standards will be applied in this way, this belief does not amount to an effective binding rule.[42]

EPA has proposed provisions which are intended to assure that the thresholds for GHG permitting under the PSD program and Title V permitting program are preserved, and that no lower threshold will apply, but admits that in certain States, depending upon the precise language of their approved PSD and Title V permitting programs, this may not be the case.[43] EPA has requested comments from the States on whether they believe their programs will effectively retain the higher GHG permitting thresholds, or whether amendments to their approved SIPs/Title V programs will be required. If such amendments are required, EPA proposes to finalize a rule to narrow its SIP approval in that State in such a way as to retain the current permitting thresholds. This rule would be finalized at the same time that the final NSPS is issued. It is not clear that EPA's proposed solution is effective, and the result could be a "gap" during which time a lower GHG permitting threshold might be applicable between the date of proposal and the date of the final NSPS and SIP narrowing rule. EPA should have included its SIP narrowing language in the proposal to assure that both provisions became effective and no unintended "gap" occurred.

## IV. EPA Is Barred From Considering Federally Assisted Demonstration Projects When Setting Performance Standards Under Section 111 of the Clean Air Act

In the proposed rule, EPA makes its "adequately demonstrated" determination predominantly based on proposed CCS demonstration projects that have received federal assistance under the EPAct05.[44] The EPAct05 encourages the development and demonstration of CCS and advanced coal technologies by authorizing multiple financial assistance programs, such as investment tax credits and direct project funding through Department of Energy Clean Coal Power Initiative (CCPI) grants. However, Congress placed specific limitations on EPA's authority to set Section 111 standards based on demonstration projects that receive federal assistance under these EPAct05 programs.

As discussed below in greater detail, these limitations expressly bar EPA from considering the three proposed commercial-scale CCS demonstration projects that remain active, which have been allocated an investment tax credit under section 48A of the Internal Revenue

[42] Proposed Rule at 1489.
[43] Proposed Rule at 1487-1488.
[44] P.L. 109-58 (Aug. 8, 2005).

Code. By law, EPA may not rely on the technology used or emissions reductions achieved at these projects in making a determination under Section 111 that CCS is adequately demonstrated. In addition, other demonstration projects receiving federal assistance under the CCPI program are barred by Section 402 of EPAct05 from EPA consideration when setting performance standards under Section 111 of the CAA.[45]

Notably, three of the four key proposed CCS projects that EPA strongly relies upon[46] have been allocated an investment tax credit that was established for "clean coal facilities" under Section 1307 of EPAct05.[47] These three projects –which are currently under development, but not yet in operation – include the Kemper County Energy Facility (Kemper), the Hydrogen Energy California (HECA) facility, and Summit Power's Texas Clean Energy Project (TCEP). Similarly, many of the smaller pilot-scale proposed CCS projects cited by EPA in the NSPS proposal have received CCPI funding as well. The probative value of the fourth proposed commercial-scale CCS project on which EPA relies – the SaskPower Boundary Dam project – is also questionable given that it has received substantial support from Canadian federal and provincial governments and also has not yet commenced operations.[48]

The exclusion of these CCS demonstration projects, as mandated by the EPAct05 prohibitions, has the effect of eviscerating EPA's already meager record in support of its determination that CCS is adequately demonstrated as the BSER under Section 111(b) of the Clean Air Act (CAA or Act). This fact further underscores the irrefutable conclusion that EPA lacks the necessary supporting evidence to determine that CCS is adequately demonstrated at this time. As a result, the Agency has no choice but to withdraw the proposed $CO_2$ performance standard for new coal-fueled power plants and establish a standard based on a holistic review of demonstrated highly efficient generating technologies.

[45] We note that Section 421(a) of EPAct05 (codified at Section 42 U.S.C. § 13571 *et. seq.*) includes language that imposes similar prohibitions on use of information from projects funded under another DOE program, referred to as the Clean Air Coal Program. Given the similarity of the statutory language, the same arguments that apply to Section 48A tax credits and CCPI subsidies provided under EPAct05 Section 402 also apply to the limitation imposed under Section 421(a). However, the Section 421(a) limitation is not discussed in these comments because no projects have received assistance under section.

[46] 79 Fed. Reg. at 1434. *See also id.* at 1478, 1479 and 1482.

[47] The investment tax credit established by section 1307 of EPAct05 is codified at section 48A of the Internal Revenue Code (IRC). 26 U.S.C. § 48A (2012).

[48] Mass. Inst. Tech., Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project, https://sequestration.mit.edu/tools/projects/boundary_dam.html (accessed Feb. 23, 2014).

### A. Section 48A(g) Clearly Bars EPA From Relying On CCS Projects to Which Section 48A Tax Credits Have Been Allocated

Section 48A(g) of the Internal Revenue Code places the following limitation on EPA's authority to set performance standards under section 111 of the Act:

> "*No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is...adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411)...*"[49]

This statutory limitation clearly and unambiguously prohibits EPA from "considering" the following three categories of evidence from a covered demonstration project to "indicate" that a "technology or performance level is...adequately demonstrated" under Section 111:

(1) "*use of technology…by or at one or more facilities with respect to which a credit is allowed*"

(2) "*a level of emission reduction solely by reason of the use of the technology…by or at one or more facilities with respect to which a credit is allowed*", and

(3) "*achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed.*"[50]

The use of the word "solely" in the second category, above, may allow EPA to take into consideration a level of emission reduction that was not achieved "*solely* by reason of the use of the technology." However, the use of the term "solely" in the second category does not limit or otherwise apply to the two other prohibitions contained in Section 48A(g). This is evidenced by the fact that the term "solely" is placed within parentheses, which indicates that it is meant to modify only the words "level of emission reduction" and not the two other statutory prohibitions.

The two additional, broader prohibitions in Section 48A(g) also bar EPA from considering information obtained from proposed CCS demonstration projects that receive Section 48A tax credits, including the Kemper, HECA, and TCEP projects. First, Section 48A(g) prohibits EPA from considering the "achievement of *any* emission reduction by the demonstration of *any* technology or performance level...by or at" a facility for which a credit is allowed.[51] Under this provision, information about *any* emission reductions achieved through

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[49] 26 U.S.C. §48A(g).
[50] 26 U.S.C. §48A(g).
[51] 26 U.S.C. §48A(g). (emphasis added)

the demonstration of *any* technology or performance level at a relevant facility may not be "considered" by EPA – regardless of whether EPA has in its possession other data or information from other sources that could support a finding that the technology or level of emission reduction is adequately demonstrated. Second, Section 48A prohibits EPA from considering the "use of technology...by or at one or more facilities with respect to which a credit is allowed."[52] Unlike the other provisions in the EPAct05,[53] and contrary to the interpretation that EPA asserts in its technical support document (TSD),[54] these other two prohibitions in Section 48A are not qualified by the term "solely" and, as a result, are not subject to any constraint that may be imposed by this term.

Thus, even if the word "solely," as used in Section 48A could allow EPA to consider information about emission reductions that were not achieved "solely by reason of the use of the technology," the other provisions of Section 48A(g) would still prevent EPA from considering the use of technology, or the achievement of particular emission levels through demonstration of technology or a performance level, at the proposed Kemper, HECA, and TCEP facilities, if those facilities are ever completed and operated. As discussed below, any limiting effect that the term "solely" might have would have no practical effect in the instant NSPS rulemaking given that

[52] *Id.*

[53] In Section 402(i), for example, the phrase containing the word "solely" is set off by commas from the word "level of emission reduction" and from the rest of the prohibition. *See* EPAct05 § 402(i). In Section 421(a), the word "solely" comes *after* references to §§ 111, 169, and 171, and is again set off by commas. Under the usual conventions of statutory interpretation, "solely" should have independent meaning in each of these non-parallel formulations. Moreover, IRC § 48A includes a separate, *additional* prohibition on consideration of the "achievement of any emission reduction by the *demonstration* of any technology or performance level" in Section 111 rulemaking. Sections 402(i) and 421(a) do not include this separate prohibition on using information from demonstrations of technology. Thus, EPA's attempt to argue that the import of the word "solely" in the context of Section 48A should be the same as in the other, differently worded provisions, would effectively negate the limitations Congress has placed on EPA's discretion.

[54] *See* EPA, Technical Support Document, Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs, at 13 (January 8, 2014) (herein referred to as "TSD"). However, EPA's argument entirely ignores the statutory text. In Section 48A(g) – unlike in other sections of EPAct05 – the term "solely" is placed within parentheses, which clearly indicates that it is meant to modify only the words "level of emission reduction" and not any other part of the prohibition. Moreover, Section 48A(g) includes a separate, additional prohibition on consideration of the "achievement of any emission reduction by the *demonstration* of any technology or performance level" in Section 111 rulemaking. EPA's assertion that these provisions are effectively the same is therefore incorrect. Finally, EPA's interpretation is inconsistent with the purpose of IRC Section 48A, which even EPA acknowledges is to encourage the development of advanced coal technology so that it can be used on a widespread commercial basis. *See* TSD at 13. Most notably, EPA's premature decision to set an achievable $CO_2$ NSPS based on undemonstrated CCS will substantially *discourage* further development of advanced coal technology by requiring this technology to be installed and maintained on a full commercial scale before the technology is ready and capable of being used in such a manner. It may also discourage participation in demonstration projects by sources, thereby discouraging important technological development.

EPA lacks sufficient evidence from non-subsidized facilities to bolster a determination that CCS is adequately demonstrated.

1. The prohibition applies to any project for which the IRS has allocated the tax credit under Section 48A

The Section 48A prohibition applies to "one or more facilities with respect to which a credit is *allowed* under this section."[55] In the Technical Support Document (TSD), EPA suggests this language could mean that the prohibition does not begin to apply until the taxpayer has actually taken or received the Section 48A credit for an eligible project.[56] Under this interpretation of the statute, the Agency notes that it may never know whether any particular demonstration project is subject to the prohibition because information about whether taxpayers have taken the tax credit is confidential, and may not be available unless taxpayers waive their right to confidentiality.[57] Information about whether an individual taxpayer has actually received or taken a tax credit is typically confidential. It therefore appears that EPA could only obtain this information by (1) violating the taxpayer confidentiality rules by obtaining this information without the taxpayer's consent from the IRS, or (2) requiring taxpayers to waive their rights to confidentiality by disclosing that they received the tax credit. Because neither of these options is legal or reasonable, EPA should adopt an interpretation of "allowed" that does not rely on disclosure of this information.

As a first principle, it would be unreasonable and unlawful for EPA to construe the statute in a way that would preclude the Agency from following the statute's directive. Rather, Section 48A should be interpreted to allow EPA to carry out its statutory obligations without compromising taxpayers' right to confidentiality and without frustrating the congressional intent of the Section 48A(g) prohibition.

Therefore, the most reasonable interpretation – and the only one that would allow EPA to follow the intent of Section 48A(g) without violating taxpayer privacy rules – would be to interpret the term "allowed" to mean that a credit for that entity was "allocated" or awarded by the IRS under Section 48A. Because the IRS is required by law to publicly disclose this information,[58] this interpretation would be administratively enforceable under existing law,

[55] 26 U.S.C. §48A(g). (emphasis added)
[56] TSD at 14-15.
[57] TSD at 13-14.
[58] *See* IRC § 48A(d)(5).

would comport with the statute's overall intent of promoting the development of clean coal technology, and would avoid EPA's claimed difficulty in identifying which projects have actually received the credit. By focusing on allocation, rather than receipt of the credit, this interpretation of the word "allowed" would also make EPA's concerns about possibly relying on information from a facility that later received a tax credit irrelevant.[59]

As a practical matter, this issue has little relevance to the three proposed, but yet-to-be-constructed commercial-scale demonstration projects that have qualified for the Section 48A tax credit. EPA already has in its possession information that shows that these projects have all been awarded a tax credit allocation under either Phase II or Phase III of Section 48A. This fact is confirmed several times in the TSD.[60] Importantly, the five-year period for placing these projects in service has not yet lapsed, so each of these projects is still eligible to take the credit if it has not already done so.[61] In addition, a project that was allocated a credit but never placed into service should not be considered for purposes of establishing a standard of performance under Section 111, because the fact that the project never entered into service, even with government support, ultimately demonstrates that it was not economically and/or technically viable. Thus, EPA can clearly comply with the Section 48A prohibition with regard to these facilities without requiring disclosure of private taxpayer information.

In addition, EPA's suggestion that the prohibition on using information from a facility might apply only to the year in which the facility is "placed in service" is not supported by the statutory language. As explained, EPA should not interpret the statute in such a way that it would be difficult for the agency to follow the law.

Section 111 of the Act does not allow EPA to make a BSER determination based on unbuilt, hypothetical demonstration projects. However, even if EPA were allowed to rely, for purposes of Section 111, on projects that have not yet been built, interpreting Section 48A(g) to allow EPA to consider such unbuilt projects that might later receive the Section 48A tax credit (*i.e.*, by placing eligible property in service at a future date) would frustrate the clear intent of Congress, which was to ensure that the technologies used and levels of emission reduction

[59] *See* TSD at 15.
[60] *See* TSD at 12, 33.
[61] Under IRC § 48A(d)(2)(E), taxpayers have five years from the date of issuance of the certification to place the project in service. Kemper received its latest certification four years ago (*see* IRS Announcement 2010-56, 2010-39 I.R.B. 398 (September 27, 2010)); HECA and TCEP received their most recent certifications last year (*see* IRS Announcement 2013-2, 2013-2 I.R.B 271 (January 7, 2013); IRS Announcement 2013-43, 2013-46 I.R.B. 524 (Nov. 12, 2013)). Therefore, the five-year period for placing these projects in service has not yet lapsed.

attained at demonstration projects receiving federal assistance under Section 48A would not be the basis of a BSER determination under Section 111. Interpreting section 48A(g) to allow EPA to rely on unbuilt projects that will in all likelihood receive federal assistance when built would frustrate this intent.

2. <u>The Section 48A(g) prohibition applies to all technology and levels of emission reduction achieved at the facility, regardless of whether the technology was the basis for the tax credit</u>

Section 48A(g) prohibits EPA from considering technology used or emission levels achieved "by or at one or more *facilities* with respect to which a credit is allowed." On its face, this provision clearly precludes EPA from considering all equipment and any emission level achieved at the *facility* – regardless of whether the equipment formed the basis for the tax credit in any given year.

The TSD, however, argues that the Section 48A(g) prohibition extends only to "eligible property" at the facility, rather than the entire facility.[62] This interpretation is unreasonable and contrary to the statute. The language of Section 48A uses both "eligible property" and "facility," but not interchangeably. For example, the statute defines "electric generation unit" to mean "any *facility* at least 50 percent of the total annual net output of which is electrical power..."[63] Meanwhile, "eligible property" is defined as "property...which is a part of [a qualifying] project."[64] (A "project" can consist of one or more electric generating units – that is, "facilities" with a total annual net electrical output of at least 50 percent.[65]) Although the items or equipment covered by the terms "eligible property" and "facility" could, in certain situations, be the same, it is also possible for a "facility" to include equipment other than "eligible property." Consequently, these terms are not equivalent, and it would be unreasonable for EPA to treat them as such by equating the word "facility" with the words "eligible property."

Moreover, in contrast to what EPA argues in the TSD, it would not be natural to read the phrase "with respect to which a credit is allowed" to modify "technology" or "level of emission reduction." Credits are not "allowed" under Section 48A for technology or for a level of emission reduction. Under Section 48A(d)(3), credits are "allowed" for "projects," which, as

[62] *See* TSD at 14.
[63] 26 U.S.C. § 48A(c)(6).
[64] *Id.* § 48A(c)(3).
[65] *Id.* § 48A(c)(6).

discussed, must "consist[] of one or more electric generation units"[66] – that is, "facilities." Furthermore, under Section 48A(e)(1)(G), all "projects" certified in Phase II or Phase III of the program must "include[] equipment which separates and sequesters at least 65 percent...of such project's total carbon dioxide emissions." Therefore, the definition of an eligible "project" clearly encompasses CCS equipment.

As a practical matter, EPA's legal argument becomes irrelevant for three of the four commercial-scale projects on which EPA relies in making its BSER determination. All three of these projects (Kemper, TCEP, and HECA) were allocated a Section 48A tax credit in either Phase II or III of the program.[67] This means that each of these federally assisted facilities by definition must include CCS technology as part of the qualifying "project," because the CCS component is required for eligibility certification under Section 48A(e)(1)(G).

In addition, the phrase "to which a credit is allowed" directly follows the word "facilities" and is not offset by a comma or other punctuation – a further indication that the authors of Section 48A(g) intended the prohibition to apply broadly to "facilities" or "projects" that receive assistance – not to specific "technologies" or "levels of emission reduction" – and certainly not to "eligible property," a phrase that is not used at all in subsection 48A(g). The way that the words "project," "facility," and "eligible property" are used in different parts of Section 48A, combined with the drafting of Section 48A(g) thus clearly indicates that Congress intended the Section 48A(g) prohibition to apply broadly to "facilities" – not just to "eligible property" – as EPA incorrectly asserts in the TSD.[68]

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[66] *See id.* 48A(e)(1)(C).

[67] *See* TSD at 12.

[68] Even if EPA were to interpret the word "facility" to mean "eligible property" (despite strong indications in the language of section 48A that the terms are not equivalent), the IRS has clarified that eligible property can include both "steam turbines, generators, foundations for generators, foundations for the power trains, silos for storage of coal, blending facilities for coal, control boards for the plant, assets necessary for steam generation," and "*assets necessary for emission control*." IRS, Office of Chief Counsel, Memorandum: Generic Legal Advice for Section 48A, at 1-2 (Feb. 15, 2008), *available at* http://www.irs.gov/pub/irs-utl/am2008004.pdf. Because Kemper, HECA, and TCEP facilities all use CCS as a form of emission control that is applied during the gasification stage of the operation, these technologies would appear to be covered by the IRS' definition of eligible property.

Moreover, EPA's proposed rule specifies that BSER for fossil fueled EGUs other than gas turbines is "efficient generation technology implementing partial CCS." 79 Fed. Reg. at 1434. That is, BSER is the combination of efficient generation technology (such as IGCC) with CCS. Consequently, even if the CCS technology being employed at these facilities is excluded from the definition of "eligible property," EPA would still be prohibited from considering the high efficiency coal gasification and combustion equipment at these facilities – equipment that clearly qualifies as "eligible property." Because this "eligible property" is integrally linked to the performance of the CCS equipment at the facility, EPA may not conclude – based on information obtained at these facilities – that

In conclusion, the only reasonable interpretation of Section 48A(g) – and the one that is the most consistent with the terms of the statute – is that the prohibition covers "*any* emission reduction by the demonstration of *any* technology," as well as the "use of technology" "*at* one or more facilities" for which a credit is allowed. This prohibition would clearly include "eligible property" under Section 48A; however, it would also cover *other* property located at the facility, such as gasification, $CO_2$ enrichment, transportation, or sequestration technologies. Moreover, because the Section 48A(g) prohibition also prohibits EPA from considering "levels of emission reduction," this prohibition should be read to include all technologies that are involved in achieving emission reductions – including, at the very least, any capture, transportation, and sequestration technologies that are essential to achieving $CO_2$ emission reductions.

**B. Section 402(i) Prohibits EPA From Relying On Federally Subsidized Demonstration Projects Given The Lack Of Supporting Documentation To Conclude That CCS Is "Adequately Demonstrated"**

Sections 401 and 402 of EPAct05 created the Clean Coal Power Initiative (CCPI), a DOE program whose goals are to "advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated..."[69] One of the key criteria for receiving assistance under the CCPI is that the project is likely "to improve the competitiveness of coal among various forms of energy in order to maintain a diversity of fuel choices in the U.S. to meet electricity generation requirements..."[70] The CCPI was clearly intended to help maintain fuel diversity and ensure that coal-fueled power plants would continue to play an important role in electricity generation by funding experimental and demonstration-stage projects that otherwise would not be built.

Section 402(i) places clear limitations on the Agency's authority to regulate stationary sources under the CAA. One such limitation is the following:

> "*No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be...adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411)...*"[71]

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"efficient generation technology implementing partial CCS" is adequately demonstrated without violating its own, unreasonably narrow interpretation of Section 48A(g).

[69] EPAct05 § 402(a).

[70] *Id.* § 402(d)(2)(B).

[71] 42 U.S.C. § 15962(i).

Although this prohibition is similar to the limitation imposed for projects qualifying for tax credits under Section 48A, there is one notable difference. Specifically, the language of Section 402(i) does not follow the syntax of Section 48A(g) of placing the term "solely" within parentheses. In the TSD, EPA argues that this difference allows for a different interpretation of the Section 402(i) limitation. Specifically, EPA incorrectly interprets Section 402(i) to "prohibit EPA from relying exclusively – 'solely' – on facilities that receive assistance under EPAct05 when determining whether a particular technology, or level of emission reduction, is adequately demonstrated for purposes of section 111 of the Clean Air Act."[72] Furthermore, the Agency insists that the Section 402(i) prohibition does not apply in those cases where EPA can point to some "other information" (however minimal) upon which it relied in making its BSER determination.[73]

This interpretation is supported by neither a plain reading of the statutory language, nor the relevant legislative history. Rather, as explained below, the correct reading of Section 402(i) is that EPA is required to have sufficient evidence from non-subsidized facilities to make a plausible or prima facie case that CCS is demonstrated before relying on information from facilities that have received federal assistance.

1. EPA must have sufficient information from non-subsidized facilities to conclude CCS is demonstrated before relying on information from facilities that have received federal assistance

EPA cannot side-step the Section 402(i) prohibition by simply pointing to a scintilla of evidence in support of its BSER determination. Rather, a more reasonable interpretation of the statute is that EPA may disregard the prohibition *only* in those situations where there is strong independent evidence, including at least one non-subsidized full-scale electric utility project, which demonstrates CCS is an "adequately demonstrated" technology. No such evidence exists.

In effect, Congress added the Section 402(i) limitation out of concern over how EPA would set CAA performance standards based on CCPI-subsidized demonstration projects. Congress' specific concern was that EPA might conclude that a technology or emission reduction level was "adequately demonstrated" *just because* ("solely by reason of" the fact that) the technology or emission reduction was achieved at a project that was funded through the CCPI program. The purpose of Section 402(i) is to prevent EPA from concluding that a

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[72] TSD at 6.
[73] TSD at 6, 13.

technology is adequately demonstrated *just because* it was demonstrated at a facility that received significant federal funding, while allowing the Agency to designate such technologies or emission levels as adequately demonstrated once they have been adequately demonstrated *elsewhere*, at facilities that did not receive assistance.[74]

The legislative history of the provision supports this interpretation. For example, the relevant House Energy and Commerce Committee Report explains that the Section 402(i) prohibition:

> *specifies that the use of a certain technology by any facility assisted under this subtitle or the achievement of certain emission reduction levels by any such facility will not result in that technology or emission reduction level being considered achievable, achievable in practice, or "adequately demonstrated" for purposes of sections 111, 169 or 171 of the Clean Air Act.*[75]

In light of this clear congressional intent, the most reasonable interpretation of Section 402(i) is that, for purposes of Section 111, EPA must have sufficient evidence from facilities (including at least one full-scale electric utility application) that *have not* received assistance under the Act before it can rely on emission data or experiences with the technology at facilities that *have* received assistance. Information from facilities that have received assistance can add *weight* to EPA's finding that a particular technology or emission level is adequately demonstrated, but it may not form the *underlying basis* for identifying that technology or emission level in the first place.

To the extent that EPA determines CCS is "adequately demonstrated" based primarily on information obtained from non-operating facilities receiving assistance under the EPAct05, this determination would violate Section 402(i). This is because it would "result in [technology used by facilities receiving assistance] or emission reduction level[s achieved at such facilities] being considered...'adequately demonstrated' for purposes of section[ ]111...of the Clean Air Act."[76]

[74] We note that EPAct05 section 421(a) includes language that imposes similar prohibitions on use of information from projects funded under that section. However, because no projects have received assistance under section 421, those sections are not relevant to EPA's current rulemaking.
[75] H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215 at 238 (July 29, 2005). H.R. 1640 is the precursor to EPAct05 that provided the blueprint for many of the clean coal programs at issue here. The Report includes a similar explanation of the prohibition contained in the Clean Air Coal Program (which became EPAct05 § 421). *Id.* at 240.
[76] H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215 at 238 (July 29, 2005).

2. <u>There is insufficient information in the record to allow EPA to rely on subsidized projects for its BSER determination</u>

As discussed, the Section 402(i) prohibition applies unless sufficient independent information exists in the record to make a credible determination that CCS is adequately demonstrated at a commercial scale. As discussed throughout the detailed technical comments that follow, EPA has failed, by a wide margin, to make such a case.

Furthermore, the TSD Appendix lists the following proposed CCS projects that EPA relied upon in their BSER evaluation, which received funding under EPAct05:

- AEP Mountaineer Plant Commercial-Scale CCS Project (cancelled)
- Southern Company Plant Barry
- NRG W.A. Parish Plant
- Coffeyville Gasification Plant
- Southern Company Kemper Project
- Texas Clean Energy Project
- Hydrogen Energy California[77]

Under EPAct05 Section 402(i), EPA should only rely on information from these projects as support for the proposed NSPS if it can *independently* conclude (based on information from facilities that have *not* received federal assistance) that the technologies used at the subsidized facilities are adequately demonstrated. Such a case simply cannot be made.

In conclusion, EPA has incorrectly determined that it may rely on the technology used or emission levels achieved at subsidized facilities as long as it also has *some* other evidence – no matter how unreliable or speculative that evidence might be. Such an argument would violate the intent of the Section 402(i) prohibition and is not a reasonable construction of the statute. By its own admission, seven of the twelve facilities on which EPA has relied in determining that CCS is BSER for fossil fueled boilers and IGCCs have received funding under EPAct05 (including three that received a Section 48A allocation).[78] One of the remaining five projects, the SaskPower Boundary Dam project received similar funding from the Canadian government. The balance of these five projects that did not receive funding under EPAct05 are either not coal-fired electric generating units or are not integrated commercial-scale CCS projects.

[77] *See* TSD at 32-33. *See also* U.S. Dept. of Energy, *Clean Coal Technology and the Clean Coal Power Initiative*, http://energy.gov/fe/science-innovation/clean-coal-research/major-demonstrations/clean-coal-technology-and-clean-coal (accessed Feb. 21, 2014).
[78] *See* TSD at 33.

Further, six of the nine EGU facilities on which EPA relies have received funding under one or more of the EPAct05 provisions. EPA's heavy reliance on CCS technology that has been proposed to be employed at these subsidized facilities strongly suggests that EPA does not have sufficient evidence from facilities that were *not* funded by EPAct05 to make an independent determination that CCS is adequately demonstrated for fossil fuel-fired electric generating units. Consequently, EPA's proposed rule violates Section 402(i) by relying heavily, if not exclusively, on projects that have received assistance under EPAct05.

### C. EPAct05 Funding For CCS Demonstration Projects Represents Congressional Judgment That This Technology Is Not Yet Adequately Demonstrated

EPA's reliance on proposed projects that have received significant federal funding, in defiance of specific prohibitions on such reliance (discussed above) is particularly troubling in light of the clear indications that Congress itself concluded that the technologies receiving this assistance were not yet adequately demonstrated, and predicated its assistance to facilities that use these technologies on the commercial *unavailability* of these technologies. For example, to be eligible for financial assistance under the CCPI, a project must "advance efficiency, environmental performance, and cost competitiveness *well beyond the level of technologies that are in commercial service...*"[79] Similarly, one criterion for financial assistance under the CCPI is that the project receiving assistance must be likely "to *demonstrate* methods and equipment that are applicable to 25 percent of [coal-fueled] electricity generating facilities."[80] The Clean Air Coal Program, which was also established in the 2005 Energy Policy Act, was likewise intended to provide assistance to technologies and projects that are not yet adequately demonstrated.[81] Meanwhile, the legislative history further demonstrates that Congress's decision to fund projects through the CCPI, Clean Air Coal Program, and the Section 48A investment tax credit was predicated on an understanding that the technologies on which EPA's proposed rule relies were not yet adequately demonstrated, and would therefore need federal assistance so that these

[79] Section 402(a) of EPAct05 (emphasis added).
[80] Section 402(d)(2)(C) of EPAct05.
[81] One of the purposes of the Clean Air Coal Program is to "facilitate the production and generation of coal-based power, through the deployment of clean coal electric generating equipment and processes that, compared to equipment or processes that are in operation on a full scale...*improve...*(i) energy efficiency; or (ii) *environmental performance...*and...*are not yet cost competitive*." Section 421(a) of EPAct05 (emphasis added).

technologies could advance to the point that one day they might be the basis of performance standards or other environmental rules.[82]

Viewed in this light, EPA's proposal to interpret Sections 402 and 48A to allow the Agency to rely on the very projects that Congress deemed not to be demonstrated would turn congressional intent on its head. EPA's decision to rely on information from these proposed projects – in spite of clear congressional intent to the contrary, and in spite of specific statutory prohibitions on such use – is arbitrary and contrary to the spirit of the law. Therefore, EPA should revise its proposed rule by proposing a performance standard whose achievability can be demonstrated by facilities that have not received assistance under federal programs that are explicitly designed for undemonstrated technologies. In doing so, it will be overwhelmingly apparent that CCS technology has not been adequately demonstrated and that high efficiency generation technologies are the BSER for fossil fuel-fired electric generation units.

[82] *See, e.g.,* S. Comm. Energy and Natural Resources, Report to Accompany S. 10, the "Energy Policy Act of 2005," S. Rep. 109–78, at 10 (June 9, 2005) ("*Innovation for the future* also includes *improving on technologies for existing fuel resources...* Clean coal initiatives have resulted in drastic reductions in emissions without limiting the ability of coal to serve as the most reliable and efficient means of electric generation. *Looking to the future*, clean coal research will ensure that new power plants meet high standards of economic viability and environmental protection."); H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215, at 171 (July 29, 2005) ("Coal also represents over 94% of the Nation's proven fossil energy reserves. Despite this abundance of recoverable resources and the Nation's historical reliance on coal for electric power generation, plans to build new coal-fired generation face obstacles. A number of factors contribute to this situation, including the high capital and operating costs of currently available clean coal technology along with uncertainty over future environmental requirements. The Clean Coal Technology Demonstration Program (CCT) has sought to address this situation and *demonstrate the feasibility of new coal-generation technology* and processes."); *id.* at 239 (explaining that the Clean Air Coal Program "amends the Energy Policy Act of 1992 by directing the Secretary of Energy to establish a program *to enhance the deployment of fully developed and commercially demonstrated clean coal technologies* including pollution control equipment...").

## V. Underlying Policy Goals Must Not Influence EPA's Analysis and Determination of the BSER for Fossil-Fuel Fired Electric Generating Units

EPA indicates that the proposed rule "reduces uncertainty...for new coal-fired generation."[83] The agency is absolutely correct. The proposed rule will not just reduce uncertainty, it will eliminate it altogether as the requirements will effectively prohibit the development of new coal-based generation units, and will have little, if any, impact on future natural gas-fired combustion turbine units. Admittedly, EPA recognizes that the proposed rule will result in "negligible $CO_2$ emissions changes..[or] quantified benefits."[84]

Perhaps, this precise outcome on future coal-based generating units was the primary driver for the lackluster, incomplete, and incorrect BSER analyses for coal-fired and natural gas combustion turbine units. If the outcome was known from the start and the impetus for the reproposal was to simply strengthen the fatally flawed 2012 proposal, then that would explain why the proposed rule appears designed more to prepare for legal appeals, than to seriously, objectively, and holistically evaluate prospective BSER candidates. It would also explain why the entire proposal lacks attention to detail, relies upon out of context information from very limited resources, and applies a double-standard for evaluating coal-based units and natural gas combustion turbines. The end result is a proposed rule that was derived from a legally and technically flawed analysis, that produces an unworkable regulatory structure, but that achieves the effective result (or goal) of eliminating coal as option for future electric generation.

EPA view on the role of coal within a balanced portfolio of energy options has evolved significantly. Only a few short years ago did EPA prepare a final report as part of *"several initiatives to facilitate and incentivize* [the] *development and deployment of*...[IGCC] *technology*."[85] EPA noted the following in the forward of that report:

> "*Currently, over 50 percent of electricity in the U.S. is generated from coal. Given that coal reserves in the U.S. are estimated to meet our energy needs over the next 250 years, coal is expected to continue to play a major role in the generation of electricity in this country. With dwindling supplies and high prices of natural gas and oil, a large proportion of the new power generation facilities built in the U.S can be expect to use coal as the main fuel... EPA considers integrated gasification combined cycle (IGCC) as one of the most promising technologies in reducing the environmental consequences of*

[83] 79 Fed Reg. 1496 (January 8, 2014).
[84] 79 Fed Reg. 1433 (January 8, 2014).
[85] "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." (July 2006) U.S. EPA. EPA-430/R-06/006. p. 1 of Forward.

> *generating electricity from coal. EPA has undertaken several initiatives to facilitate and incentivize development and deployment of this technology*."

With the proposal rule, EPA has not only eliminated any opportunity for coal "*to continue to play a major role in the generation of electricity in this country*," but also has eliminated the chance for future coal units to play any role. In fact, EPA somewhat disparagingly discusses those who consider energy diversity to include coal by noting that:

> "*We are aware of another segment of the industry.....who have indicated a preference for new coal-fired generation to establish or maintain fuel diversity in their generation portfolio because their customers have a expressed a willingness to pay a premium for that diversity. It appears these utilities and project developers see lower risks to long-term reliance on coal-fired generation and greater risks to long-term reliance on natural gas-fired generation, compared to the rest of the industry*."[86]

Without question, in the eight years since EPA finalized this report, significant developments within the energy industry have occurred that have dramatically transformed the natural gas and oil industries and that have accelerated the development and use of alternative energy technologies. However, EPA should not misconstrue such developments to automatically assume that natural gas is the fuel of the future and will be a readily available substitute to coal-based generation. To do so is extremely naive, devalues the benefits of energy diversity, ignores a long history of volatility in energy supply expectations, and is complacent to the ever increasing challenges to the development of natural gas generating units.

For example, in the 1950's nuclear energy was expected to be too cheap to meter, the energy crisis of the 1970's increased reliance on coal-based generation and led to a ban on the use of natural gas-based generation, low natural gas prices in the 1990's led to rapid expansion of simple- and combined-cycle units, while high natural gas prices and rising electrical demand led to a significant build out of new coal-based generation units in the 2000's, including the failed pursuit of many IGCC projects. Most recently, the development of shale gas techniques has increased the supply and reduced the price of domestic natural gas, which has again shifted new generation development to natural gas processes. EPA's confidence that the deployment of natural gas generating units will continue well into the future is evident in the proposed rule where the agency notes that:

[86] 79 Fed Reg. 1478. (January 8, 2014)

"*we recognize that...**the higher costs of CCS may tilt the economics against new coal-fired construction**. Even in this case the standard would remain valid..., particularly because **the basic demand for electricity could still be served by NGCC**.*"

and

"*...even **if requiring CCS adds sufficient costs to prevent a new coal-fired plant from constructing** in a particular part of the country to due to the lack of available EOR to defray the costs, or, in fact, from constructing at all, **a new NGCC plant can be built to serve the electricity demand that the coal-fired plant would otherwise serve.** Thus, the present rulemaking does not prevent basic electricity demand from being met.*"[87]

Whether or not, and for how long, a strong reliance on natural gas will continue for new generation resources is to be determined. A long history of natural gas price volatility and pattern of shifting interest in energy resources suggest great caution against any strategy that devalues the importance of a balanced energy portfolio. The proposed rule states that

"*EPA believes that it is appropriate....to set a standard that is robust across a full range of possible futures in the energy and electricity sectors.*"[88]

The "full range of possible futures" that EPA contemplates is premised solely on the expanded use of natural gas. EPA's logic that natural gas units will continue to be a readily available option and can be readily developed as replacement for coal-fired generation is greatly misguided as EPA ignores the mounting pressures on natural gas generation development. The press headlines below are just a small sampling of the increased development concerns:

- "Groups Oppose Switching NY Plant from Coal to Gas"[89] (New York)
- "Seminole Tribe Leads Protest Walk Against Gas-Fired Power Plant"[90] (Florida)
- "Local Environmental Groups Oppose Proposed Natural Gas Power Plant..."[91] (Massachusetts)
- "$500 Million [natural gas] Power Plant Proposal Divides Tiny Morristown"[92] (Indiana)
- "El Paso [natural gas] Power Plant Draws Community Opposition"[93] (Texas)
- "Proposed Hess [natural gas] Plant...Faces Community Opposition"[94] (New Jersey)
- "Proposed [natural gas] Power Plant....Gains Opposition"[95] (Pennsylvania)
- "Push for New Gas Power Plants Draws Fire"[96] (California)
- "Residents Divided over...[natural gas] Power Plant Project"[97] (Minnesota)
- "Attorney Cautions Power Generators as Pipeline Capacity Cushion Grows Smaller"[98]

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87 79 Fed. Reg. 1481 (January 8, 2014)
88 79 Fed. Reg. 1434 (January 8, 2014)
89 Nov 14, 2013. http://online.wsj.com/article/AP37275691611b44ba83bbeda4d63725f2.html
90 Feb 25, 2014. http://climate-connections.org/2014/03/04/seminole-tribe-leads-protest-walk-against-gas-fired-power-plant/
91 Mar 27, 2012. www.boston.com/yourtown/news/salem/2012/03/local_environmental_groups_opp.html
92 Sep 7, 2013. http://archive.indystar.com/article/20130905/NEWS/309050033/-500-million-power-plant-proposal-divides-tiny-Morristown
93 Apr 5, 2013. www.texastribune.org/2013/04/05/el-paso-power-plant-draws-community-opposition/
94 May 2, 2012. www.wnyc.org/story/205800-proposed-hess-plant-newark-faces-community-opposition/
95 Jan 8, 2013. www.muncyluminary.com
96 Aug 2, 2012. www.utsandiego.com/news/2012/Aug/02/push-for-new-power-plants/
97 Dec 28, 2009. www.mprnews.org/story/2009/12/28/north-branch-plant-opposition

Clearly, the development timeline and scope of concerns for natural gas-fired generation resources is becoming and will continue to be more challenging. As such, there is no certainty that future natural gas generating units can automatically "*be built to serve the electricity demand that the coal-fired power plant would otherwise serve*" or that "*the present rulemaking does not prevent basic electricity demand from being met*." Nonetheless, EPA references EIA estimates that over 45 GW of new natural gas generation capacity will come online by 2025.[99] Based on conservative estimates, potential $CO_2$ emissions from this added capacity alone would be over 70 tonnes per year.[100]

EPA states that it is to "*crucial to take initial steps now to limit GHG emissions from fossil fuel-fired power plants*" because these emissions "*threatens the American public's health and welfare*."[101] Yet, the agency points out that proposed rule will only "*limit GHG emissions from new sources...to levels consistent with current projections for new fossil fuel-fired generating units*."[102] Therefore, if the magnitude of these threats is a severe as EPA has stated; if the significance of these risks require immediate reductions in GHG emissions; and if EPA's logic for determining that CCS is available for coal-based generation is equally compelling for NGCC process, then why doesn't EPA require NGCC units to use CCS to reduce the potential 70 million tonnes of new $CO_2$ emissions from these sources as well? The answer is two-fold. First, as noted throughout our comments, CCS <u>has not</u> been proven to be technically feasible or adequately demonstrated at a commercial scale for NGCC or coal-based generating units. Second, requiring CCS for NGCC units would effectively prohibit the development of any fossil fuel based generation technology – an outcome that would prevent meeting the "basic electricity demand," and would "threaten the American public's health and welfare." In other words, the proposed rule supports a policy that effectively eliminates coal-based power generation and preserves, at least for the near-term, the continued use of natural gas combustion turbines – this is not the purpose of the NSPS regulatory program.

The purpose of the NSPS regulatory program is to establish a standard of performances that "reflects the degree of emission limitation achievable through the application of the best

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98 Mar 5, 2014. www.snl.com/InteractiveX/article.aspx?CDID=A-27124594-12078&KPLT=4
99 EPA Regulatory Impact Analysis in support of proposed GHG NSPS (79 Fed Reg 1430). p. 5-8.
100 [(17.4 GW new NGCC)*(1,000 lb $CO_2$/MWh)*(1 tonne/2204.6 lb)*(1000 MW/GW)*(8760 hr/yr)*(75% cap factor)] + [(28 GW new CT) * (1,100 lb $CO_2$/MWh)*(1 tonne/2204.6lb)*(1000 MW/GW)*(8760 hr/yr)*(15% CF)] = 70,211,921 million tonnes/yr
101 79 Fed Reg. 1433. (January 8, 2014)
102 79 Fed Reg. 1496. (January 8, 2014)

system of emission reduction."[103] NSPS is not an appropriate vehicle for establishing a domestic energy policy that effectively restricts fuel choices and that selectively requires only certain sources to employ control technologies have not been adequately demonstrated or proven to be technically feasible at a commercial scale.

## VI. Federal Agencies May Not Infringe or Override Traditional State Sovereign Powers

In August of 2013, AEP submitted supplemental comments on the April 2012 proposal, outlining the limitations on EPA's ability to infringe on States' sovereign role in regulating electricity generation. As set forth in those comments, States have retained authority for the regulation of electricity production and no federal statute provides EPA with authority to preempt state decisions regarding the need for, location of, design, services provided by, or rates to be charged to recover the costs of electricity generation. EPA's standard of 1,100 pounds of $CO_2$ per MWh of electricity and its reliance on CCS to support that standard, usurp States' authority to incentivize siting and development of the more efficient coal-fired generating technologies that EPA rejected in establishing the standard. It fails to recognize the broader role coal production and handling play in the economies of certain States, and the unavailability of economic opportunities for CCS to be used in conjunction with EOR opportunities.

As stated by the Supreme Court, "Need for new power facilities, their economic feasibility, and rates and services are areas that have been characteristically governed by the States…"[104] The Clean Air Act, like the Atomic Energy Act of 1954, governs narrow aspects of the operation of energy generating facilities, and is not a wholesale delegation of authority to EPA to make decision on the need, cost, reliability and feasibility of building new coal plants. Indeed, other federal energy legislation, like EPAct05, recognize the value of fuel diversity and the need to encourage the development of clean coal technologies. EPA's proposal is an attempt to assure that coal is "priced out of the market" for the foreseeable future.

AEP incorporates by reference the comments submitted in August of 2012, a copy of which is attached hereto.[105] EPA should perform a much more robust analysis of the potential implications of the standard selected by the agency, similar to the analyses that underlie prior NSPS standards. Specifically, EPA should perform an economic analysis of the effect of

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103 Clean Air Act Section 111(a)(1)
104 *Pacific Gas & Electric v. State Energy Resource Conservation & Development Comm.*, 461 U.S. 190, 205 (1983).
105 See Appendix E.

adopting a standard based on the highly efficient generation technologies identified in its proposal, and the impact such a standard would have on future generation choices and $CO_2$ emissions. The analysis should include, as have past NSPS proposals, analysis of the broader impacts on coal utilization, employment, and technological development of alternatives to CCS.

## VII. EPA Has Failed to Demonstrate that Any Increase in Title V Fees is Warranted

As noted, the U.S. Supreme Court is currently reviewing the agency's determination that the issuance of GHG standards for new motor vehicles triggers the applicability of Title V permitting requirements for stationary sources.[106] The outcome of that litigation is not yet known. However, if EPA's Title V regulations are upheld, EPA has not demonstrated that any adjustment to Title V emission fees is necessary, and EPA should exempt GHG emissions from Title V fees unless and until any proposed increase has been fully justified.

EPA has an extensive discussion of alternative proposals to increase the collection of Title V emission fees to account for the "incremental burden" associated with GHG permitting activities under Title V.[107] However, the fundamental question is whether, given that the proposed NSPS is not anticipated to expand the universe of sources subject to regulation, and that those sources would already be subject to Title V permitting requirements based on emissions of other regulated pollutants which are subject to fee payments, there is any reason to believe that an incremental fee collection is necessary. EPA itself admits that there is support in existing analyses for the proposition that no additional fee revenue is necessary, and this conclusion is intuitively sound.[108] In the absence of any clear demonstration that existing fee collections are inadequate, or that the proposed rule produces an incremental burden that is significantly different from the burden that accompanies any other revision of an NSPS, there is no basis to conclude that Title V fees are generally inadequate to support the statutorily mandated activities, and EPA should categorically exclude GHGs from Title V permit fees.

[106] *UARG v. EPA*, Case No. 12-1146 and consolidated cases, *cert. granted* Oct. 15, 2012.
[107] Proposed Rule at 1490-1495.
[108] Proposed Rule at 1495.

## VIII. Partial CCS is Not the BSER for Fossil Fuel-Fired Boilers and IGCC Units

### A. EPA's "best judgment" fails to demonstrate that CCS is the BSER

EPA's BSER determination considered four key factors: (i) technical feasibility, (ii) cost, (iii) emission reductions, and (iv) the promotion of technology development. EPA's evaluation of each of these factors and their "best judgment" of the BSER is flawed due to:

- a series of premature, inaccurate conclusions on the development, demonstration, and performance of advanced generation and CCS technologies;
- minimal consideration and an abrupt dismissal of widely-acknowledged barriers to CCS becoming a technically feasible and adequately demonstrated control option;
- an inadequate consideration of the lessons learned from actual projects and the conclusions reached by major public and private assessments of CCS development;
- an inconsistent use of criteria to perform the BSER analyses and to inform the Administrator's judgment within this proposal and compared to other rulemakings;
- an inadequate evaluation of the impacts to all sources within the source category; and
- use of underlying energy policy goals that do not allow for an objective evaluation of BSER in accordance with the Clean Air Act.

EPA uses the following analogy to describe its decision-making process for evaluating and determining the best system of emission reductions:

> "*the determination of what is 'best' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the 'best' sprinter in the 100-meter dash depends on only one criterion – speed – and therefore is relatively straightforward, while the question of who is the 'best' baseball player depends on a more complex weighing of several criteria and therefore requires a greater exercise of judgment*."[109]

While judgment is necessary, the agency has the tremendous responsibility to exercise that judgment based on a fair, objective, and holistic consideration of facts. EPA has not done this. Rather, by expansion of the aforementioned analogy, EPA's approach for exercising their judgment of the "best" baseball player (e.g. best system of emission reductions) is equivalent to relying on the conversations at a high school reunion where has-been baseball teammates reminisce using inflated statistics, tales of games that never happened, and vague recollections about walking to practice ten-miles, uphill and in the snow. This is precisely the type of logic the D.C. Circuit Court stated EPA should avoid – and that EPA quoted in the proposed rule – by noting that:

[109] 79 Fed. Reg. 1466. (January 8, 2014)

> "*...EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable <u>on mere speculation or conjecture</u>*"[110]

With respect to carbon capture and storage, the scope of technical, financial, regulatory, and legal considerations is indeed "complex and necessarily requires an exercise of judgment." In the proposed rule, EPA describes, defends, and promotes the use of "major assessments" in applying judgment to their decision-making process on complex issues in other recent assessments by noting that:

> "*the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment...was to <u>rely primarily upon the recent, major assessments</u>...*"[111]

and:

> "*<u>Primary reliance on the major scientific assessments</u> provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community, <u>rather than selecting the studies it would rely on.</u>*"[112]

EPA clearly acknowledged the value of using major assessments to strongly inform its judgment on complex issues. Unfortunately, these values were not applied in the current EPA proposal as EPA ignores most of major assessments that are available regarding the challenges and opportunities for CCS and highly efficient electric generation technologies. Numerous public and private entities have completed (and continue to undertake) major assessments of CCS development. These are well documented and were, in part, summarized in AEP comments to EPA on the 2012 proposed 111(b) standards.[113] Of this large number of major assessments on CCS development, EPA narrowly considered only a very small fraction of the available information to inform its judgment. That fraction represents a limited literature review, minimal (if any) consideration of lessons learned from projects under development, a reliance on unrepresentative CCS experience from other industries, and the expected, but not demonstrated, performance of yet-to-be-constructed projects.

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[110] Id. 1479. (emphasis added)
[111] Id. 1438. (emphasis added)
[112] Id. 1456. (emphasis added)
[113] AEP Comments to EPA Regarding April 12, 2012 Proposed NSPS. p. 42 & Appendix D. Submitted June 25, 2012. Docket ID: EPA-HQ-OAR-2011-0660-10038

To illustrate this point, EPA used over 3,000 words[114] in the proposed rule to describe and defend their use of major assessments in prior rulemakings, but in evaluating the technical feasibility of CCS dedicated only 250 words[115] to their "literature review" and approximately 2,500 words[116] to their technical feasibility discussion of "capture, transportation, and storage technologies." As detailed in the following sections, EPA should significantly expand the scope of information considered in the BSER analysis to include the full range of available major assessments and other more relevant information. Doing so would be consistent with the approach EPA acknowledges is necessary for "complex" evaluations and would well position the agency to exercise their 'best judgment" in making a determination on CCS – a determination that will clearly indicate that CCS technologies (full and partial capture) are not the BSER for fossil fuel-fired generation and IGCC units.

### B. EPA has misinterpreted the realities and prospects of CCS development

For many years, strategies to reduce GHG emissions have been contemplated by policymakers, driven research and development, and influenced electric utility planning. Increasing attention by policymakers has led to a general acceptance that at some future point, a GHG reduction program would be implemented although the scope and timing of requirements were and remain unknown.

In planning for the possibility of GHG regulation, the electric utility community has considered **potential** emission control technologies and broader reduction strategies that **may become available**. In parallel, the U.S. Department of Energy, along with other public and private efforts, have correctly (and consistently) recognized that **potential** $CO_2$ emission reduction technologies, including CCS for fossil fuel-based electric generation processes, **must overcome significant development barriers if they are to have any chance of becoming** a technically feasible and commercially viable control option.

This recognition of the likelihood of $CO_2$ regulations and **speculation** on the potential availability, cost, and performance of CCS and other reduction strategies is helpful in attempting to forecast future needs, as well as to guide research and development efforts to meet those needs. However, this recognition **is not an affirmation or an endorsement** that CCS is

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[114] 79 Fed. Reg. pp. 1438-1441. (Jan 8, 2014) Total Words in Section II. A. 3 "The Science Upon Which the Agency Relies".
[115] Id. p. 1471. Total Words in Section VII. E.1 "Literature"
[116] Id. pp. 1471-1474. Total Words in Section VII. E.2.a-c "Capture, Transportation, an d Storage Technologies"

currently or ever will be technically feasible or adequately demonstrated as a $CO_2$ emission control option for fossil fuel-based power generation.

AEP's own CCS experience highlights the fact that **CCS is far from being proven to be technically feasible or adequately demonstrated** at a commercial-scale due to an array of technical, financial, regulatory, legal, and practical barriers.[117] Numerous public and private programs have concluded the same.[118] EPA has failed even to begin to fully consider these various public and private studies. The EPA also fails to give even a cursory evaluation of the lessons learned from advanced generation and CCS projects that have actually operated, including AEP's Mountaineer Plant CCS program. As a result, EPA's BSER evaluation demonstrates a poor understanding of the state of CCS development, the development barriers that exist, and the prospects for successfully overcoming these barriers.

EPA ignores most of these development barriers and relies on an overly simplistic assessment to discredit their significance. EPA suggests that "the costs of $CO_2$ capture and compression represent the largest barriers to widespread commercialization of CCS."[119] While lowering capture and compression costs is a significant challenge, it is only one of many that impede the prospects of CCS becoming technically feasible, adequately demonstrated, and commercially viable. EPA's focus on capture costs grossly understates the breadth of barriers by downplaying the significant technical challenges that exist for *capture* systems and the equally significant technical, cost, and legal challenges for *transport* and *storage* systems.

These challenges cannot be addressed merely through desktop studies, research papers, engineering exercises, or technical specifications. It is critical that solutions to these challenges are developed and physically demonstrated with proven performance at a commercial-scale, while being exposed to the full gamut of commercial-scale power plant conditions. These solutions are a prerequisite to CCS becoming a technically feasible and adequately demonstrated $CO_2$ control option. EPA alludes to this process in the context of evaluating CCS for natural gas combustion turbines by noting that "*we cannot assume that the technology can be easily*

[117] See Section IX.A for comments related to the AEP Mountaineer Plant CCS Program.
[118] See Section IX.B for examples of public and private efforts that determined that CCS has not yet been proven to be technically feasible or adequately demonstrated for fossil fuel-based power generation.
[119] 79 Fed. Reg. 1471. (January 8, 2014).

*transferred to NGCC <u>without larger scale demonstration projects on units operating more like a typical NGCC</u>.*"[120]

Although the U.S. leads the world in advancing the development of CCS related technologies, significant research, development, and demonstration work remains. For example, the CCPI was established to "<u>accelerate the development</u> of advanced coal technologies with carbon capture and storage at commercial-scale" through the demonstration of technologies that "<u>make progress toward</u> a target $CO_2$ capture efficiency of 90 percent" and that "<u>make progress toward</u> a capture and sequestration goal" that minimizes the resulting increased cost in electricity.[121] This program is indicative that CCS remains under development, not that it has been proven to be technically feasible and adequately demonstrated. Otherwise, the purpose of the CCPI would be to optimize mature technologies, and not to develop emerging or potential technologies. Round III of the CCPI selected six projects to "accelerate" and "make progress" the development of commercial-scale CCS. If these were six successfully completed projects, then a case could begin to be made that CCS is technically feasible, adequately demonstrated, and ready for commercial deployment. However, not a single one has commenced operation. Two are actively being constructed. The others are cancelled or must overcome major challenges to be able to begin construction. Indeed, most are no more developed than the conceptual work completed to initiate the project.

Successful development must be advanced in a systematic and step-wise manner. AEP began the process of advancing CCS to a commercial-scale. Even if the AEP commercial-scale CCS project had remained active, the project would not have been in service until at least 2015. AEP's expectation then was that commercial-scale CCS demonstrations were needed immediately *(e.g. 2015)*, so that in 2020, *at the earliest*, a reliable commercial-scale CCS process *might* be adequately demonstrated and ready for deployment. With the suspension of the AEP project and as other CCS projects are delayed or discontinued, the date for the commercial readiness of CCS technology continues to move farther into the future. Based on the current state of development, a reasonable estimate for CCS to be adequately demonstrated and commercially viable is at least ten years away – and this assumes that current financial and

[120] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[121] http://energy.gov/fe/clean-coal-power-initiative-round-iii. (Accessed January 29, 2014)

regulatory barriers are immediately removed. Without a clear path forward, the status of CCS development will remain, perhaps indefinitely, at least ten years away.

In summary, increased policy, research, and planning efforts focused on CCS development have advanced the knowledge of challenges and opportunities, but significant time and investment must be spent in order to address these development barriers. EPA has misinterpreted the purpose and outcome these efforts. The following comments demonstrate how far EPA missed the mark in their analysis and demonstrate that CCS is not the BSER.

### C. Technical feasibility is not the same as adequately demonstrated

Varying degrees of technical feasibility can be determined through desktop calculations, laboratory studies, pilot-scale testing, large-scale demonstrations, or other methods. As such, a process that is technically feasible is not necessarily adequately demonstrated or commercially viable.[122] A determination of adequate demonstration cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial-scale on representative processes, allows for the optimization of systems integration and performance, and provides for cost-effective design options that can be safely and reliably operated. Absent this process, a technically feasible process remains just that – technically feasible and no more. Currently, CCS has yet to be adequately demonstrated at a commercial-scale on a coal-based electric generating unit.

### D. EPA's assessment of CCS is inconsistent with other EPA actions

EPA's position on the feasibility and adequate demonstration of CCS in the proposed rule are in many ways contradictory to its assessment of the technology in the *PSD and Title V Permitting Guidance for Greenhouse Gases* document. Throughout the guidance document, EPA suggests that CCS be considered in a BACT analysis and that CCS will likely not apply because it is not technically feasible and/or because it is not cost-effective - both reasons also support the conclusion that CCS has not been adequately demonstrated. The following are excerpts from the guidance document in regards to CCS development:

- "*While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases*."[123]

[122] Technical feasibility, by itself, is insufficient to satisfy the BSER criteria of 111(a) of the Clean Air Act.
[123] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36.

- "*Based on these* [technical, cost, logistical, etc.] *considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.*"[124]

- "*EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2* [Technical Feasibility Analysis] *of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis* [Economic, Energy, and Environmental Impacts Analysis]*, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible.*"[125]

Based on these and other reasons, EPA indicates that CCS will likely not qualify as BACT. If the level of development is insufficient to generally apply CCS as BACT, it is also insufficient to support the determination that CCS is the BSER.

**E. EPA's technical feasibility evaluation fails to demonstrate that CCS is the BSER**

Technical feasibility is one of the key factors in the evaluation of the BSER. EPA's technical feasibility evaluation is comprised of a literature review and references to examples of CCS-related projects. Overall, EPA's assessment of technical feasibility is insufficient and relies on inaccurate conclusions that do not demonstrate that CCS is the BSER.

1. <u>EPA's literature review does not demonstrate that CCS is the BSER</u>

EPA determines that CCS is the BSER in part "through an extensive literature record."[126] Despite the broad number of published major assessments, reports, and research papers on CCS development issues, the "extensive literature record" that EPA evaluated consisted of *only three* resources: (i) the 2010 Interagency Task Force on CCS Report, (ii) a 2009 Pacific Northwest National Laboratory study of the commercial availability of CCS technologies, and (iii) a 2011 DOE/NETL report titled "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture." If taken in proper context and thoroughly read, none of these resources conclude commercial-scale CCS has been sufficiently proven to be technically feasible or adequately demonstrated for coal-based generating units. In contrast, these reports identify many

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[124] Id.
[125] Id. at. pp 42-43.
[126] 79 Fed. Reg. 1471. (January 8, 2014).

of the technical, financial, regulatory, and integration barriers to broader CCS development and acknowledge that it will take time and additional research and development to address these issues. It is also noteworthy that *none* of the reports considers the lessons learned and experiences of actual projects such as the AEP Mountaineer CCS validation-scale plant, or the CCS projects under development for coal-based electric generation that EPA references in the proposed rule. A review of each report follows.

*a. <u>Review of 2010 Interagency Task Force on CCS Report</u>*

EPA misinterprets the findings of President Obama's Interagency Task Force on Carbon Capture and Storage ("Task Force") in their evaluation of CCS at the BSER. The charge of the report alone does not support the determination that CCS has been proven to be technically feasibility or adequately demonstrated for fossil fuel-based generating units. As EPA points out:

> "*The Task Force was charged to propose a plan to <u>overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years</u>, with a goal of bringing five to ten commercial demonstration projects online by 2016*."[127]

EPA summarizes the report as follows:

> "*The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, <u>first-of-a-kind technology risks</u>, and the current cost of CCS relative to other technologies, there are <u>no insurmountable technological, legal, institutional, regulatory or other barriers</u> that prevent CCS from playing a role in reducing GHG emissions*."[128]

Describing these barriers as not being insurmountable is one thing, but acknowledging the time and resources required to overcome these barriers is another. For example, the barriers for mankind to travel to Mars are not insurmountable, but significant technical and financial challenges must first be addressed. EPA is either naive about or has chosen to ignore the magnitude of CCS development challenges. The Task Force was neither. As noted above, the very charge of the Task Force was to propose a plan to overcome these barriers <u>within 10 years</u>!

What the EPA does not point out is that the Task Force also found that "*barriers hamper near-term and long-term demonstration and deployment of CCS technology*."[129] In essence, an ambitious near-term research, development, and demonstration program would need to be implemented in order to overcome barriers to the commercialization of CCS. To date, such

[127] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[128] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[129] Report of the Interagency Task Force on Carbon Capture and Storage, p. 14 (Aug 2010).

programs have yet to produce a single operating commercial-scale demonstration project at a coal-based generating unit and are not on pace to achieve the five to ten projects by 2016 that the Task Force recommended for overcoming barriers by 2020.

Finally, it is noteworthy that Task Force alludes to the deployment of CCS projects as being "first-of-a-kind technology", which accurately describes its state of development. This point seems to be lost by EPA in their cost evaluation of CCS as discussed in detail later.

*b.* *Review of Pacific Northwest National Laboratory Report: An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*

EPA also relies upon on a 2009 report from the Pacific Northwest National Laboratory ("PNNL") to evaluate the availability of CCS. Specifically, EPA states:

> "*(PNNL) recently prepared a study*" and that the "*study concluded, in general, CCS is technically viable today and that key component technologies of complete CCS system have been deployed at scales large enough to meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants*."[130]

The "recently prepared" study was completed over four years ago. Many major assessments of CCS development have been completed since that would provide more updated perspectives. Terms that EPA relies upon such as "in general" and "meaningfully inform discussions" are far from being equivalent to technically feasible and adequately demonstrated at a commercial scale on a coal-based electric generating unit. In addition, the report does not suggest that CCS has been proven to be technically feasible and adequately demonstrated for fossil-fuel based generating units, rather the study acknowledges that:

> "*The limited, early large scale commercial adoption of complete, end-to-end CCS systems which has taken place to date has occurred outside the electric power sector*."[131]

and that

> "*there is truth to the often heard assertion that CCS has never been demonstrated at the scale of a large commercial power plant*."[132]

Among the greatest and widely recognized barriers to CCS development for fossil-fuel based generation units are those technical and financial challenges associated with integrating

[130] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[131] "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. Pacific Northwest National Laboratory. Dooley, et.al. PNNL-18520. June 2009. p. 4. (emphasis added)
[132] Id. p. 7. (emphasis added)

various components of CCS technology with power plant operations. The study does not attempt to evaluate the magnitude of these integration challenges. To the contrary, the study notes that:

> "[o]*ne explicit goal of this paper is to* *examine – in a disaggregated manner – the status of CCS technologies and their component systems.*"[133]

The PNNL study caveats its results by referencing how much work remains for CCS development. The following qualifiers do not support EPA's determination that CCS the BSER:

> "*The fact that.....CCS systems exist and the needed system components of a CCS system are commercially available does not undercut the rationale for* *a vigorous ongoing research, development and demonstration program* *focused on improving CCS technologies and demonstrating them in various combinations of technological, geographical, and geologic applications and settings.*"[134]

and

> "*The deployment of CCS.....will need a more clearly defined regulatory framework" for issues such as "property and mineral rights, and settlement of liability concerns related to the long-term storage of* $CO_2$*.*"[135]

*c. Review of 2011 DOE/NETL Report: "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture"*

The report contains no information on the lesson learned and experience of actual projects, but rather relies upon incomplete, vendor-supplied data of technologies that have never been constructed or integrated. A strong critique of this report is provided in the comments below on EPA cost analysis. In short, these comments demonstrate that the report is insufficient for providing reliable cost assessments that can meaningfully assess the state of CCS technology and that the report is insufficient for determining whether the CCS has been proven to be technically feasible and adequately demonstrated at a commercial scale.

2. The project examples identified by EPA do not demonstrate that CCS is technically feasible or adequately demonstrated

A determination that CCS is technically feasible and has been adequately demonstrated cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial-scale on representative processes, allows for the optimization of systems integration and performance, and provides for cost-effective design

[133] Id. p. 4. (emphasis added)
[134] Id. p. 2. (emphasis added)
[135] Id. p. 3. (emphasis added)

options that can be safely and reliably operated. EPA correctly alludes to these steps as being necessary for determining the technical feasibility of CCS as follows:

> "*The EPA considered whether NGCC with CCS could be identified as the BSER...and we decided that it could not be. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units.*"[136]

and

> "*This cyclical operation, combined with the already low concentration of $CO_2$ in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical* [unit]."[137]

While EPA makes these statements in the context of its consideration of CCS for natural gas combustion turbines, the concerns are equally applicable to fossil fuel EGUs and IGCC units:

- where a much greater volume of $CO_2$ must be captured, transported, and sequestered;
- where CCS has not been demonstrated at a commercial scale;
- where it "*cannot* [be] *assume*[d] *that the technology can be easily transferred*";
- where there have been no "*larger scale demonstration projects on units operating like a typical* [unit]; and
- where "*there is insufficient information to make a determination regarding the technical feasibility of implementing CCS.*"

In a flawed attempt to prove that these concerns have been addressed for coal-based generating units, EPA references 25 examples of CCS and CCS-related efforts in the proposed rule. A detailed analysis of each is provided Appendix A. None of these examples, independently or collectively, is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units. A summary of this analysis of the project examples that EPA relies upon in the proposed rule found that:

- **Only** 6 of the 25 EPA examples represent commercial-scale CCS integrated with coal-based generating units. Of these six examples:
  - **None** are operational
  - **All** represent first-of-a-kind $CO_2$ capture technologies on a coal-based generating unit
  - 4 of the 6 examples represent first-of-a-kind combustion technologies
  - Only 2 of the 6 are undergoing active construction

[136] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[137] Id. (emphasis added)

- The 4 remaining projects are "planned" to startup between 2016 and 2019
- Prospects for the 4 remaining projects are questionable due to financial challenges and a lack of regulatory approvals
- **<u>None</u>** of the 6 examples is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units.

▪ 8 of the 25 EPA examples are of carbon capture efforts from fossil fuel-based generating units that are **<u>insufficient</u>** in size, among other factors, to assess commercial-scale CCS performance or viability
  - 2 of the 8 examples are validation-scale CCS projects on coal-based generating units that are proof-of-concept projects, **<u>not commercial-scale demonstration efforts</u>**
  - 4 of the 8 examples capture $CO_2$ from slip-streams of coal-based and natural gas combustion turbine units for food and soda ash industries; **these are not commercial-scale demonstration efforts and lack any geologic storage component**
  - 2 of the 8 examples are for "planned" projects that have not been officially announced

▪ One of the 25 EPA examples represents a validation-scale oxy-combustion project (10MWe) that is **not a commercial-scale demonstration and lacks geologic storage**

▪ 8 of the 25 EPA examples are $CO_2$ sequestration efforts. Of these eight examples:
  - **<u>None</u>** are integrated with a fossil fuel-fired electric generating unit
  - Only 5 of the 8 are active processes
  - 2 of the 8 are "potential projects", while one of the examples discontinued operation
  - **<u>None</u>** of the 8 examples is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units.

▪ 2 of the 25 EPA examples are databases that summarize CCS development
  - <u>GCCSI Database</u>: Only 2 of the 60 power generation CCS efforts are "active" projects, the balance are "planned." These 2 projects offer no new information as they are specifically identified in the proposed rule and accounted for above.
  - <u>DOE CCUS database</u>: It does not list any noteworthy CCS efforts beyond those specifically identified in the proposed rule and accounted for above. In fact, much of the information appears to be very dated and inaccurate.

In fact, only two of the 25 EPA examples are actively undergoing construction and represent commercial-scale CCS projects integrated with coal-based generation units. While these two efforts will advance the knowledge of CCS opportunities and challenges, they are far from being sufficient to make a regulatory determination that CCS is technically feasible and adequately demonstrated because their operation and performance capabilities are to be determined. In addition, one unit is a first-of-a-kind (FOAK) IGCC project, while both projects will utilize FOAK CCS technologies. It is to be determined whether the cost-escalations experienced by both projects, as well as the technical risks and performance uncertainties that are inherent with any FOAK process can be adequately addressed to make the next generation of technologies viable for potential developers. The experience, positive or negative, of these two efforts, alone, will be insufficient to determine if the technology is feasible or adequately demonstrated as suggested by several major assessments. For example, EPA references the Final Report of the Interagency Task Force on CCS by noting that:

> "*The Task Force was charged with proposing a plan to overcome the barriers to widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016*" [138]

The two CCS projects referenced by EPA that are actively being constructed are likely to be the only two demonstration projects online by 2016. This amount falls short of the 5 to 10 projects identified by the Task Force as necessary to overcome significant development barriers – barriers the prohibit any determination that commercial-scale CCS for coal-based generating units is technically feasible and adequately demonstrated.

Finally, EPA's premature reliance on undeveloped or unrelated CCS and CCS-related examples is inconsistent with its evaluation of one project that was under development when the proposed rule was signed – the Wolverine Power Cooperative coal-based power plant in Michigan. In regards to the Wolverine project, the proposed rule notes that:

- "*EPA is not proposing standards today for one conventional coal-fired EGU project which, based on current information, appears to be the only such project under development that has an active air permit and that has not already commenced construction*"[139] (emphasis added)
- "*If the EPA observes that the project is truly proceeding, it may propose a...*[NSPS]*...specifically for that source*[140]" (emphasis added)
- "*EPA has not formulated a view as to the project's status in the development process*"[141] (emphasis added)

At the time of the proposed rule, the Wolverine Project had obtained an air permit, was actively seeking financing, but had not started construction. Based on this information EPA was unable to "formulate a view as to the project's status" and was unable to determine if "the project is truly proceeding." Yet, in many regards, the Wolverine Project as described was much farther

[138] 79 Fed. Reg. 1471 (January 8, 2014)
[139] 79 Fed. Reg. 1434 (January 8, 2014)
[140] 79 Fed. Reg. 1434 (January 8, 2014)
[141] 79 Fed. Reg. 1461 (January 8, 2014)

along then many of the CCS examples that EPA relies upon, which **do not** have an air permit or other regulatory approvals, face **more significant** financial challenges, and **have not** started construction (i.e. the Hydrogen Electric California project). Ironically, EPA was able to overlook these more substantial development barriers to not only "formulate a view" that these CCS projects are "truly proceeding," but also EPA was able to extend this "view" to conclude that these projects are proof that commercial-scale CCS is technically feasible and is being adequately demonstrated. EPA's view is simply incorrect. EPA is also incorrect in asserting that

> "*the Wolverine project appears to be the only fossil fuel-fired boiler or IGCC EGU project presently under development that may be capable of 'commencing construction' for NSPS purposes in the very near future and, as currently designed, could not meet the 1,100 lb $CO_2$/MWh standard*"[142]

There is no basis to determine that *any* of the coal-based CCS projects identified by EPA could meet the proposed NSPS. These projects are not regulated to achieve a specific $CO_2$ limit and, where applicable, are only required to demonstrate the performance of the CCS system for a specified period. Thus, significant uncertainty exists as to whether the proposed limit will ever be achieved over the short- or long-term operation of these projects, to the extent they are even constructed.

3. EPA Has Misinterpreted the Experiences of Other Industries in the Evaluation of Technical Feasibility of CCS for Fossil Generation Sources

EPA incorrectly uses the experience of other industries to support their evaluation of CCS for fossil fuel-fired electric generating sources. For example, EPA notes that "*the capture of $CO_2$ from industrial gas streams has occurred since the 1930's using a variety of approaches*."[143] For EPA to suggest that capture technologies should be readily transferable to coal-based electric generating units because of a long history of use in other industries ignores the multitude of technical, process design, and operational differences between the "industrial gas streams" referenced and a coal-based power plant. It also ignores the significant difference in the quantities and end use of the captured $CO_2$, which will be orders of magnitude greater from coal-based generation units than that for most "industrial gas streams." In addition, the likely end-use for coal-based $CO_2$ will be geologic sequestration or enhanced oil recovery

142 79 Fed. Reg. 1461 (January 8, 2014). (emphasis added)
143 79 Fed. Reg. 1471. (January 8, 2014).

processes, which pose much different challenges than capture from industrial gas streams "to produce food and chemical-grade $CO_2$."[144] The agency also notes that pre-combustion, post-combustion, and oxy-combustion capture systems are technically feasible.[145] However, *none* of these capture systems has been adequately demonstrated at a coal-based power plant on a commercial-scale as either an independent process or, more importantly, as an integrated process with a $CO_2$ utilization or geologic storage system.

### F. EPA's cost analysis fails to demonstrate that CCS is the BSER

Cost related issues are another key component of the evaluation of the BSER. EPA has a long history of demanding comprehensive cost evaluations as part of the BACT analyses process for much more established emission control technologies. It would only be reasonable to expect that EPA would, at the very least, demand the same of itself in evaluating an emerging technology such as CCS where first-of-a-kind commercial projects have yet to occur and where the inherent scope and magnitude of considerations and uncertainties at issue makes developing useful cost estimates tenuous even when considering the best of all available information. Instead, EPA's cost analysis is flawed throughout and produces highly suspect and unreliable conclusions due to:

- an incorrect assessment of the development status of CCS, which results in using cost estimates for yet-to-be realized more mature $n^{th}$-of-a-kind ("NOAK") type technologies, rather than initial first-of-a-kind ("FOAK") technologies;
- a narrow reliance on two reports that are based on dated vendor supplied conceptual designs for CCS and IGCC technologies that have **never** been constructed or proven;
- a failure to consider **any** of the costs and lessons learned from actual CCS related projects that have been constructed or that are actively being developed; and
- a failure to consider more recent and relevant studies of the cost of advanced coal-based generation and CCS technologies.

The result of these fallacies is a reliance by EPA on cost estimates that are "*somewhere between FOAK and NOAK*" despite the agency alluding to CCS in the same paragraph as being an "*emerging technology*", "*not yet fully mature*", and "*not yet...serially deployed in a commercial context*".[146] The use by EPA of CCS costs that are premised on the conjecture of NOAK projects does not remotely provide reliable, accurate estimates, is irrelevant for use in

[144] 79 Fed. Reg. 1471. (January 8, 2014).
[145] Id. 1472.
[146] 79 Fed. Reg. 1476. (January 8, 2014)

preforming any objective analysis of new generation options, and has the appearance of being nothing more than weak attempt to justify a preconceived BSER outcome that could not otherwise be validated through the use of more reasonable and accurate information.

1. EPA's cost analysis is flawed due to an incorrect assumption that CCS development has advanced beyond first-of-a-kind technologies

Costs along the development timeline for any technology are dependent on the starting point of FOAK projects, the scope of cost reduction opportunities, and the rate at which these opportunities are realized in future projects. At present, FOAK projects that integrate CCS and coal-based generation technologies are only being to be developed. Significant uncertainties remain regarding the costs of known and unknown variables and with respect to the scope and prospects of opportunities to lower these costs. As such, reliable demonstrated FOAK costs for CCS and advanced coal generation technologies, such as IGCC, *are not available.* The current state of CCS development has been widely recognized to be at the FOAK deployment phase, including by the Interagency Task Force on CCS.[147] This is ignored by EPA, which notes that:

> "*For an emerging technology like CCS, costs can be estimated for a 'first-of-a-kind' (FOAK) plant or an 'n$^{th}$-of-a-kind' (NOAK) plant, the later of which has lower costs due to the 'learning by doing' and risk reduction benefits that will result from serial deployments as well as from continuing research, development, and demonstration projects.*"[148]

EPA's assessment is incorrect. Where CCS currently stands on that timeline today makes estimating cost for any projects beyond FOAK technologies premature and nothing more than fanciful speculation. The current state of CCS development has not moved beyond FOAK projects, which are only beginning to be constructed and where cost estimates have varied widely and continue to escalate. Reliable baseline costs, performance information, and lessons learned from FOAK CCS projects are required before the true scope of cost implications can be understood. Because CCS development issues are far from being one-sized-fits-all, the completion of multiple commercial-scale projects on coal-based generating units is critical for informing for any meaningful cost estimate of future NOAK CCS processes. Likewise, EPA's requisite "learning by doing" is premature because the only relevant commercial-scale "doing" that can be referenced is the construction of two FOAK CCS projects and ambitious conceptual designs of projects that may never occur. Further, to the extent any "doing" has occurred, such

[147] Report of the Interagency Task Force on Carbon Capture and Storage. (Aug 2010). p. 8.
[148] 79 Fed. Reg. 1476. (January 8, 2014).

as the AEP Mountaineer Plant CCS Validation Project, the cost, performance, and other lessons learned from these efforts are not considered in the DOE/NETL reports that EPA relies upon.

2. EPA's cost analysis is flawed due to a narrow review of available information and a failure to consider the cost of actual projects

EPA's cost analysis relies on *only two* DOE/NETL reports that are based on conceptual designs for technologies that, at least in the case IGCC and CCS, have never been constructed. In fact, much of the cost analysis language contained in the preamble is verbatim from these reports, albeit without appropriate references.

These reports identify some of the cost drivers for CCS and advanced coal technologies, but are insufficient for providing reliable cost assessments for use in regulatory development or in planning future projects. For example:

- EPA uses CCS cost estimates that represent more mature, NOAK type technologies, even though FOAK technologies have **not yet** been demonstrated. The result is an overly optimistic and incorrect conclusion that CCS costs will be lower that what otherwise could be reasonably estimated.

- EPA uses cost estimates that range from -15% to +30%. Such a wide range is indicative of a FOAK type technologies, but **not** technologies that have advanced beyond FOAK.[149]

- EPA uses cost estimates that evaluate generation and CCS technologies that only use bituminous coals. **No consideration** was given to the use of lower rank coals.

- The cost estimates are premised on vendor supplied information for 12 different plant configurations that represents six IGCC designs, 2 subcritical pulverized coal designs, 2 supercritical pulverized coal designs, 1 synthetic natural gas ("SNG") production plant, and 1 repowering of an existing NGCC plant with SNG. Of note, **neither** the IGCC unit designs, nor the SNG-related process have ever been constructed. Also, **no consideration** was given to ultra-supercritical pulverized coal configurations.[150]

- The cost estimates for the above mentioned 12 units assumed that carbon capture was achieved through the use of the Fluor Econamine FG Plus capture process for pulverized coal unit and the use of a water-shift reactor and a two-stage Selexol process for IGCC units. **Neither** carbon capture process has been ever been demonstrated on a coal based generating unit at any level, and certainly not at a commercial-scale.[151]

[149] 79 Fed. Reg. 1476. (January 8, 2014).
[150] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010). p. 1
[151] Id. p.4

- Dated cost estimates were derived from modeling conducted in 2009 and 2010.[152]

- The cost estimates for geologic storage systems are overly simplistic generalizations that are not representative of the high costs associated with the characterization, development, and operation of injection and monitoring wells. Due to the age of the study, no estimates are included for the anticipated high costs for complying with the EPA Class VI Underground Injection Control ("UIC") program. In fact, the UIC program had not been finalized when the study was completed.

- EPA references a number of CCS related projects to support their BSER analysis and acknowledges that "*the lessons learned from design, construction, and operation of those projects...*["*currently under development*"]*...will help lower cost for future gasification facilities implementing CCS*."[153] Despite the value of these "lessons learned," the DOE reports that EPA relies upon give **<u>no consideration</u>** of the very projects that EPA utilizes to justify their BSER determination.

Background on the cost estimating methodology employed in these two NETL studies that EPA relies upon is described in a separate NETL report, which characterizes the approach as "techno-economic studies." Specifically, NETL notes the following with respect to the design of these studies and the value of the results:

> "*Conceptual cost estimates used in techno-economic studies are typically factored from previous estimation data and <u>are not accurate as actual detailed estimates</u>*."
>
> and
>
> "*Most techno-economic studies completed by NETL feature cost estimates carrying an accuracy of -15 percent/+30 percent, consistent with a "feasibility study"...level of design engineering applied to the various cases... <u>The reader is cautioned</u> that the values generated for many techno-economic studies have been developed for the specific purpose of comparing relative cost of differing technologies. <u>They are not intended to represent a definitive point cost nor are they generally FOAK values</u>*."[154]

The cost information in these two reports does represent the costs that are being estimated and incurred by the active CCS and advanced coal-based generation projects, which are more refined and representative. However, caution should be noted as well in interpreting and applying these actual project costs as the estimates vary widely and continue to escalate, and the information may not be applicable for projecting the cost of future projects.

[152] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010). (e.g. p. 125: Oct 8, 2009; p. 156: Jan 14, 2010)
[153] 79 Fed. Reg. 1476. (January 8, 2014).
[154] "Technology Learning Curve (FOAK to NOAK)" (Aug 2013). NETL p. 5. (emphasis added)

Given the uncertainty with estimating FOAK CCS project, the ability to quantify potential cost reductions for future CCS projects is tenuous at best. A recent report by the Congressional Research Services addresses this issue by noting:

> "*The challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States.*"[155]
>
> and
>
> "[C]*osts for technologies tend to peak for projects in the demonstration phase of development... What the cost curve will look like, namely, how fast costs will decline and over what time period, is an open question and will likely depend on if and how quickly CCS technology is deployed on new and existing power plants*."[156]

In fact, development costd may actually *increase* as the technologies mature. For example, in the 2012 proposed GHG NSPS EPA referenced one study by Rubin, et. al that evaluated this issue.[157] That study found:

> "*there is currently little empirical data to support the assumptions and models used to calculate future $CO_2$ capture costs for power plants*," and that "*there are no easy or reliable methods...to quantify the magnitude of potential cost increases commonly observed during early commercialization.*"
>
> and in regards to the methodology of their analysis, the study states:
>
> "[o]*ne drawback of this approach is that it does not explicitly include potential cost increases that may arise when building or combining components that have not yet been proven for the application and/or scale assumed.* [In addition] *a study of this nature...has other important limitations that must be recognized. For one, the concept of a constant learning rate... often...is an over-simplification of actual cost trends for large-scale technologies.*"[158]

Therefore, EPA should factor into their analysis that development costs may actually increase, and increase dramatically as new information is discovered. NETL has recognized this very issue in noting that:

> "*...cost reductions do not always begin with the second plant... In some cases, the FOAK plant experience also leads to unpredictable problems and the realization that more components or more expensive components are needed, resulting in the next installation*

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[155] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service. p. 6

[156] Id. p. 11

[157] 77 Fed. Reg. 22416. (April 13, 2012)

[158] Rubin, E.S., et. al. "Use of experience curves to estimate the future cost of power plants with $CO_2$ capture." International Journal of Greenhouse Gas Control I, pp. 189-196 (2007) (emphasis added).

*again being fundamentally different. In these cases, the costs may actually increase for the first few installations."*[159]

A recent Congressional Research Services report reaffirms this conclusion by noting that the knowledge gained though research, demonstration, and initial operating experience sometimes results in *increased* costs during the development period, and the magnitude and rate of development is not a one-size-fits-all trend.[160]

3. <u>The experience of recent projects and findings of major studies demonstrate that EPA's cost analysis is flawed and that CCS is not the BSER</u>

The recent experience of CCS and advanced coal-based generation projects underscores the difficulty of developing reliable costs FOAK technologies, yet alone the significant uncertainty and challenge of being able to assess the cost of future FOAK and especially NOAK projects with any degree of accuracy. This difficulty is highlighted by the projects that EPA relies upon in the proposed rule where there is a wide disparity in costs and where each project is experiencing significant cost escalations. The risk of relying on cost estimates for FOAK CCS projects was noted by an executive from SaskPower in regards to their Boundary Dam CCS project that is currently being constructed:

Interview Question: "*Stepping back, what does your project mean for the entire race to commercialize CCS?"*

Answer: "*Well, the significance for me is, if you look at what people are guessing as the cost of capturing carbon, that is all it is, is a guess. There is so much swing in estimating what the capture costs* [are], *that it makes the numbers senseless.*"
Mike Monea – SaskPower President, CCS Initiatives[161]

A number of recent assessments have concluded that CCS for fossil fuel-fired electric generation currently is and will remain at the FOAK level of development for many years. These conclusions do not support EPA's use of cost estimates that the agency presumes represent technologies that have matured beyond FOAK projects. For example, the 2010 DOE/NETL CCS Roadmap noted that the DOE RD&D effort "*involves pursuing advanced CCS technology...so that full-scale demonstrations can <u>begin by 2020</u>*" in order to "*enable broader commercial deployment of CCS to <u>begin by 2030</u>.*" The report also notes that "*advanced*

[159] "Technology Learning Curve (FOAK to NOAK)" (August 2013). NETL p. 2.
[160] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700, at pp. 6, 9 (September 30, 2013).
[161] SNL Energy interview with Monea, M. (May 31, 2013). www.snl.com/InteractiveX/article.aspx?ID=17840071

*technologies developed in the CCS RD&D effort need to be tested at full scale...before they are ready for commercial deployment.*"[162] In addition, the DOE/NETL "Carbon Capture" website discusses the following in the very first paragraph:

> "*first-generation $CO_2$ capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale, require approximately one-third of the plant's steam and power to operate, and are cost prohibitive.*"[163]

The DOE CCS Roadmap also estimates that commercial-scale CCS will add 80% to the cost of electricity for a new pulverized coal unit and 35% to the cost of a new IGCC unit and highlights the infancy of the technology as a potential emissions control option for coal-based generation.[164] In addition, the DOE/NETL website indicates that one of their CCS research and development goals is to develop "*2nd-Generation technologies that are ready for demonstration in the 2020-2025 timeframe (with commercial deployment beginning in 2025).*"[165] It is clear from this information that cost estimates for future CCS projects are far from being able to accurately represent NOAK processes.

A separate NETL report notes "*the definition of the NOAK plant is somewhat arbitrary as well, although it is often taken as the fifth or higher plant.*" Given that initial commercial-scale CCS projects on coal-based electric generating units have not yet been demonstrated and only two projects are actively being constructed, the technology is many years from even approaching a fifth generation plant that could be characterized as a NOAK technology. NETL also cautions how projects are characterized in the development process by noting that:

> "*Care is needed in defining FOAK and NOAK. For major new facilities, the number of installations is largely applicable to a specific supplier's technology. For example, although the gasification technologies are similar, it is unlikely that one vendor will share sufficient experience that benefit rivals such that learning will occur.... Projects that use $N^{th}$ plant technology in some of the plant, but that use large, new, critical subsystems elsewhere should also be considered FOAK.*"[166]

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[162] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap, pp. 10-11 (Dec. 2010). (emphasis added)
[163] www.netl.doe.gov/research/coal/carbon-capture (Accessed Mar. 3, 2014) (emphasis added)
[164] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec. 2010). p. 10
[165] www.netl.doe.gov/research/coal/carbon-capture/goals-targets (Accessed March 3, 2014)
[166] "Technology Learning Curve (FOAK to NOAK)" (Aug 2013). NETL p. 2.

In other words, the minimal commercial-scale CCS projects that are actively being developed may be sufficiently unique as to limit the overall progress of the technology beyond FOAK applications.

For any individual project, the cost estimate will change throughout the phases of development: (i) conceptual design; (ii) front-end engineering & design (FEED); (iii) detailed design; (iv) construction; (v) startup & commission; (vi) operational. As technologies mature, the cost differential between conceptual design and operational cost will become less. This cost differential for an individual project can vary significantly across the development cycle, as well as from project to project that employ FOAK technologies. The tables that follow summarize costs of actual CCS projects that have been or that currently are being developed to demonstrate this variability and to highlight the fact that CCS technology is far from advancing beyond a FOAK level of development.

**Summary of Escalating Cost Estimates at Critical Project Milestones for Ongoing Commercial-Scale CCS Demonstrations**

| Company | Unit | Output | Conceptual Design | FEED[167] | Detailed Design | Construction | Startup & Commissioning | Type |
|---|---|---|---|---|---|---|---|---|
| Kemper (Southern Co) | IGCC with CCS/EOR | 582 MWn | $2.4 billion[168] | --- | --- | $5.5 billion[169] | --- | FOAK: IGCC Design<br>FOAK: Integrated CCS |
| Tx Clean Energy Project (Summit) | IGCC/Polygen with CCS/EOR | 400 MWg<br>130-212 MWn | $1.73 billion[170] | $3.8 billion | --- | --- | --- | FOAK: IGCC/Polygen<br>FOAK: Integrated CCS[171] |
| Hydrogen Energy California | IGCC/Polygen with CCS/EOR | 405-431 MWg<br>151-266 MWn[172] | $4 billion[173] | --- | --- | --- | --- | FOAK: IGCC/Polygen<br>FOAK: Integrated CCS |
| Boundary Dam[174] (SaskPower) | PC (rebuild) with CCS/EOR | 160 MWg<br>110 MWn | $1.24 billion ($354 million for rebuild) | --- | --- | $1.355 billion[175] | --- | FOAK: Integrated CCS |
| W.A. Parish (NRG Energy) | PC (retrofit) with CCS/EOR | Capture from 250MWe[176] | $338 million[177] | $775 million | --- | --- | --- | FOAK: Integrated CCS |
| FutureGen 2.0[178] | PC (retrofit) with CCS | 168 MWg | $1.3 billion ($740 million for rebuild)[179] | $1.77 billion | --- | --- | --- | FOAK: Oxy-combustion PC<br>FOAK: Integrated CCS |

167 Unless noted, all FEED costs from: Ackiewicz, M. (January 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
168 Mississippi Public Service Commission Order. RE: CPCN Petition from Mississippi Power Company. Docket 2009-UA-14. April 30, 2010. p. 4
169 "Southern Co delays advanced coal plant to 2015 amid rising costs." (April 29, 2014). O'Grady. E. Reuters.
170 76 Fed. Reg. 60478 (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.
171 www.texascleanenergyproject.com/ (accesses Feb 24, 2014) [FOAK Reference]
172 HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf
173 Ackiewicz, M. (January 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
174 Data from unless noted: Boundary Dam CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/boundary_dam.html (accessed February 24, 2014)
175 www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html
176 Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p. 3
177 W.A. Parish CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/wa_parish.html (accessed February 24, 2014)
178 Data from unless noted: 79 Fed. Reg 3578. (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project
179 "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. R43028. p.1

**Summary of Escalating Cost Estimates at Critical Project Milestones for Other Utility Projects**

| Company | Unit | Output | Conceptual Design | FEED | Detailed Design | Construction | Startup & Commissioning | Type |
|---|---|---|---|---|---|---|---|---|
| AEP John W. Turk[180] | Ultrasupercritical Pulverized Coal No CCS | 600 MWg | $1.3 billion[181] | --- | --- | --- | $1.8 billion | First USC coal generating unit in the United States |
| AEP Mountaineer[182] (validation-scale) No longer in-service | Existing PC (1300 MW plant) CCS validation-scale project | Capture from 25MWe slip-stream | $100 million | --- | --- | --- | $100 million | First integrated CCS project on a coal-based generating unit in the world |
| AEP Mountaineer[183] (commercial-scale) Project Cancelled | Existing PC (1300 MW plant) CCS commercial-scale project | Capture from 235MWe slip-stream | $668 million | $1 billion (plus $300 million cost risk for UIC compliance) | --- | --- | --- | FOAK: Integrated CCS |
| Tenaska Trailblazer[184] Project Cancelled | PC with CCS/EOR | 765 MWg 600 MWn | $2.5 billion[185] | $3.5 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |
| Edwardsport (Duke Energy) | IGCC No CCS | 618 MWg[186] | $2 billion[187] | --- | --- | --- | $3.5 billion[188] | FOAK: IGCC Design |
| Tenaska Taylorville[189] Project Cancelled | IGCC with CCS | 716 MWg 602 MWn | $2 billion[190] | $3.5 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |
| FutureGen1.0[191] Project Cancelled | IGCC with CCS | 275 MW | $950 million | $1.8 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |

180 Unless noted data for Turk Plant from: www.aep.com/newsroom/newsreleases/?id=1795 (December 20, 2012)
181 www.aep.com/newsroom/newsreleases/Default.aspx?id=1367
182 Data for Mountaineer Validation-Scale project from: "AEP CCS Program Overview" Spitznogle. (March 11, 2011) AEP. www.sseb.org/wp-content/uploads/2010/05/Gary-Spitznogle.pdf
183 Data for Mountaineer Commercial Scale project from: www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report
184 Unless noted, Trailblazer data from: "Update on Tenaska Trailblazer Energy Center" http://cctft.org/wp-content/uploads/2013/02/Jeff-James-Tenaska.pdf
185 www.power-eng.com/articles/2009/01/tenaskas-coal-fired-igcc-plant-moves-forward.html
186 www.duke-energy.com/power-plants/coal-fired/edwardsport.asp
187 Q1 2008 Duke Energy Corporation Earnings Conference Call. Conference Call Transcript. (May 2, 2008) p. 6
188 Thompson, G. Direct Testimony to Indiana Utility Regulatory Commission. Filed December 23, 2013. Exhibit B-1.
189 Unless noted, Taylorville data from: "Taylorville Energy Facility Cost Report" (February 26, 2010). Worley Parsons. www.icc.illinois.gov/electricity/tenaska.aspx
190 www.power-eng.com/articles/2007/06/tenaska-obtains-illinois-clean-coal-plant-permit.html
191 Data for FutureGen 1.0 is from: "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. p.11

The cost escalation and $/kW estimates for the aforementioned projects are summarized below:

| Project | Design | CCS | Status | Conceptual Cost Estimate ($ billion) | Most Recent Cost Estimate ($ billion) | Project Cost Escalation (%) |
|---|---|---|---|---|---|---|
| Kemper | IGCC | CCS | active | 2.4 | 5.5 | **129%** |
| Texas Clean Energy Project | IGCC/poly | CCS | active | 1.73 | 3.8 | **120%** |
| Hydrogen Energy California | IGCC/poly | CCS | active | 4 | --- | **---** |
| FutureGen 2.0 | IGCC | CCS | active | 1.3 | 1.77 | **36%** |
| Taylorville | IGCC | CCS | cancelled | 2 | 3.5 | **75%** |
| FutureGen 1.0 | IGCC | CCS | cancelled | 0.95 | 1.8 | **89%** |
| Edwardsport | IGCC | No CCS | constructed | 2 | 3.5 | **75%** |
| Boundary Dam (overall costs) | PC (rebuilt) | CCS | active | 1.24 | 1.355 | **9%** |
| Boundary Dam (CCS costs) | PC (rebuilt) | CCS | active | 0.89 | 1 | **12%** |
| W.A. Parish | Existing PC | CCS | active | 0.338 | 0.775 | **129%** |
| Mountaineer (Validation-scale CCS) | Existing PC | CCS | completed | --- | 0.1 | **---** |
| Mountaineer (Commercial-scale CCS) | Existing PC | CCS | cancelled | 0.668 | 1 | **50%** |
| Mountaineer (Commercial-scale CCS) With Estimated UIC cost risk | Existing PC | CCS | cancelled | 0.668 | 1.3 | **95%** |
| Trailblazer | PC | CCS | cancelled | 2.5 | 3.5 | **40%** |
| John W. Turk | USC PC | No CCS | constructed | 1.3 | 1.8 | **38%** |

Concerns that EPA's cost evaluation relies only on the two NETL reports become even more pronounced when considering the large difference of the estimated costs projected by EPA in the proposed rule and the actual costs that active CCS projects are incurring. The table below summarizes this comparison.

| | Unit Type | GHG Control | $/kw (net) |
|---|---|---|---|
| Hydrogen Energy California[192] | IGCC | CCS | $16,000 |
| Texas Clean Energy Project[193] | IGCC | CCS | $15,510 |
| Kemper[194] | IGCC | CCS | $9,450 |
| FutureGen 1.0[195] | IGCC | CCS | $6,545 |
| Taylorville[196] | IGCC | CCS | $5,814 |
| Trailblazer[197] | IGCC | CCS | $4,167 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | IGCC | CCS | $4,451 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | IGCC | CCS | $3,802 |
| | | | |
| FutureGen 2.0[200] | PC/Retrofit | CCS | $17,879 |
| Boundary Dam (retrofit and CCS)[201] | PC/Retrofit | CCS | $12,318 |
| Boundary Dam (CCS only)[201] | PC | CCS | $9,091 |
| W.A. Parish[202] | PC | CCS | $3,100 |
| Mountaineer (validation scale) | PC | CCS | $5,000 |
| Mountaineer (commercial scale) | PC | CCS | $4,255 |
| Mountaineer (commercial scale + UIC) | PC | CCS | $5,532 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | PC-supercritical | CCS | $4,070 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | PC-supercritical | CCS | $3,972 |

192 https://sequestration.mit.edu/tools/projects/DOE%20projects/CCPI%20projects/HECA-Tech-Update-2011.pdf
193 https://sequestration.mit.edu/tools/projects/tcep.html
194 www.reuters.com/article/2014/04/29/utilities-southern-kemper-idUSL2N0NL2K220140429
195 www.powermag.com/cover-story-futuregen-zero-emission-power-plant-of-the-future/?pagenum=2
196 http://sequestration.mit.edu/tools/projects/taylorville.html
197 http://sequestration.mit.edu/tools/projects/tenaska.html
198 "*Cost & Performance Baseline for Fossil Energy Plants*" Rev 2a. (Sept 2013). NETL p. 5
199 "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*" Rev 1. (Sept 2013) NETL. pp. 16-17.
200 http://energy.gov/sites/prod/files/2013/04/f0/EIS-0460-DEIS-Summary-2013.pdf
201 https://sequestration.mit.edu/tools/projects/boundary_dam.html
202 www.netl.doe.gov/publications/others/nepa/deis_sept/EIS-0473D_Summary.pdf

| | Unit Type | GHG Control | $/kw (net) |
|---|---|---|---|
| Edwardsport[203] | IGCC | none | $5,538 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | IGCC | No CCS | $3,097 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | IGCC | No CCS | $2,790 |
| | | | |
| Turk | PC-USC | none | $2,885 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*" [198] | PC-supercritical | No CCS | $2,296 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*" [199] | PC-supercritical | No CCS | $2,296 |

Strong conclusions can be drawn from the cost estimates above regarding the state and cost of CCS development for coal-based generating units, including the following:

- All of the projects are utilizing FOAK technologies
- All of the projects are very expensive. The active projects that remain are financially supported with significant government resources
- All of the projects have experienced significant cost escalations (up to 129% increase)
- The cost estimates between projects varies significantly
- The magnitude of costs, large degree of variation between project estimates, and significant cost escalations are <u>all</u> indicative of the application of FOAK technologies.

These conclusions represent a significant, if not prohibitive, barrier to the development of future CCS projects. These types of financial challenges for developing CCS technologies for coal-based generating projects have been widely recognized. For example:

- On February 11, 2014, Deputy Assistant Secretary of Energy Dr. Julio Friedmann testified that first generation carbon capture technology on coal-based generating plants will increase the cost of electricity by 70 to 80%.[204]
- In 2013, the Global CCS Institute estimated first-of-a-kind CCS would increase the cost of electricity by 61 to 76% for post-combustion processes and 37% for IGCC units.[205]
- 2010 DOE/NETL CCS Roadmap estimated CCS will add 80% to the cost of a new pulverized coal plant and 35% to the cost of a new IGCC plant.[206]

[203] www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/presentations/EdwardsportIGCC-041609.pdf
[204] Friedmann, J. Oral Testimony before U.S. House of Representatives Committee on Energy and Commerce. (Feb. 11, 2014)
[205] "The Global Status of CCS: 2013". (Oct. 2013). Global CCS Institute. p 172.
[206] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec. 2010). p. 10

The following contrasts the types of CCS-related cost escalations that EPA relies upon in their analysis of the BSER:

**EPA Cost Analysis of CCS Technologies**[207]

| Unit | Configuration | LCOE ($/MWh) | CCS Related Cost Increase | EPA Conclusion |
|---|---|---|---|---|
| SCPC | No CCS | 92 | --- | --- |
| SCPC | Partial CCS, No EOR | 110 | 20% | Justifies partial capture as the BSER |
| SCPC | Full, 90% CCS | 147 | 60% | Too expensive. Full capture eliminated as BSER |
| IGCC | No CCS | 97 | --- | --- |
| IGCC | Partial CCS, No EOR | 109 | 12% | Justifies partial capture as the BSER |
| IGCC | Full, 90% CCS | 136 | 40% | Too expensive. Full capture eliminated as BSER |

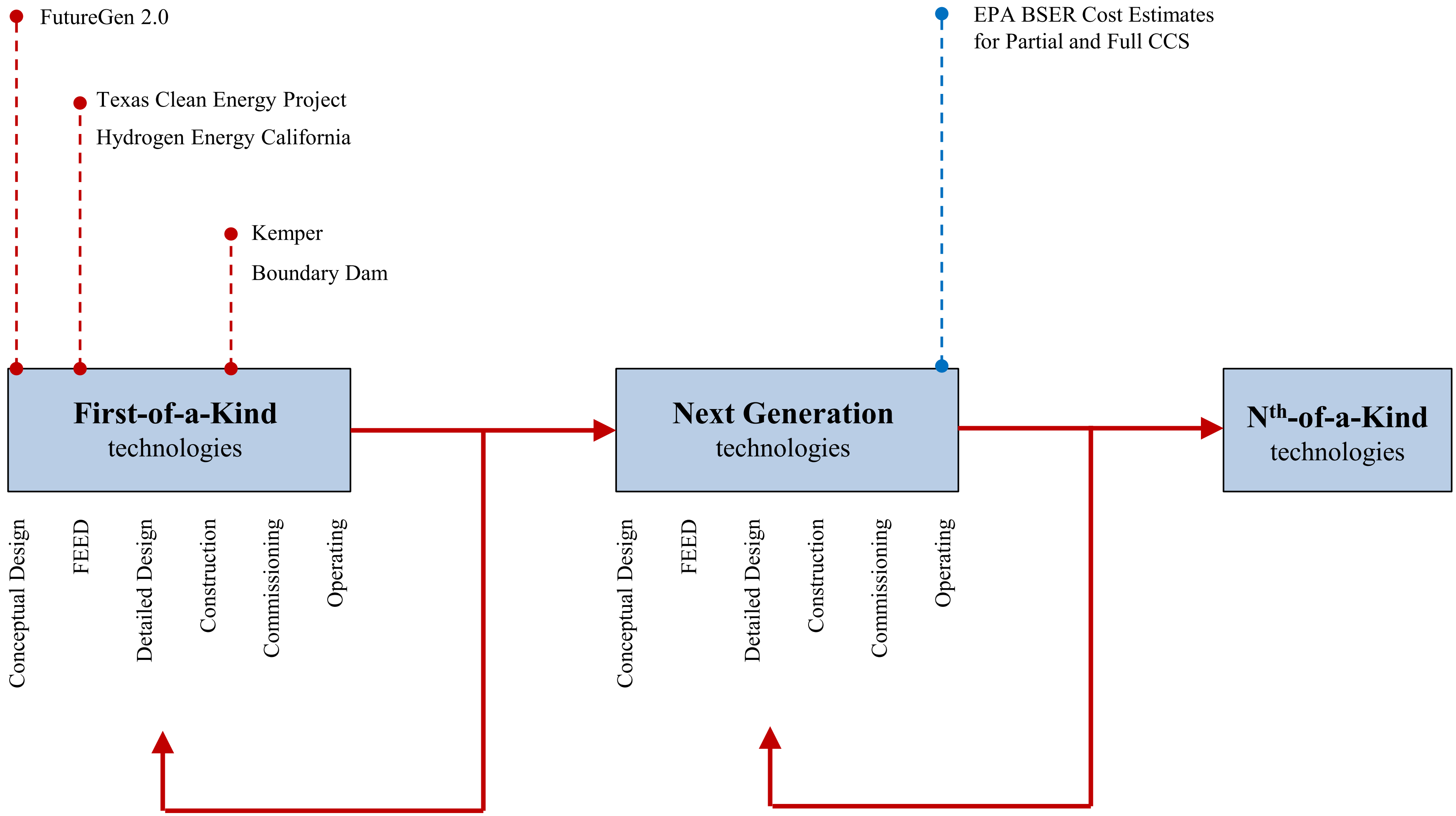
When compared to cost of actual projects and the assessments from organizations that are much more directly involved CCS development, EPA's cost assessment misses the mark by a very wide margin both in terms of the magnitude of costs involved and their conclusions on the current state of CCS development. For example, EPA's range of a 12 to 60% cost increase for CCS is far below the estimates of DOE and others that approach 80% or more

The figure on the following page contrasts the state of development represented by active CCS related projects and by EPA's BSER cost evaluation. The figure indicates that EPA's cost estimates are very ambitious and not representative of the actual state of CCS development. As (and if) these active CCS projects are constructed and operated, the lessons learned will lead to future designs that may themselves be characterized as FOAK technologies as well, or to future designs of next generation, optimized technologies that represent progress towards the development of technically feasible processes than can potentially be adequately demonstrated.

In conclusion, the flawed cost estimates that EPA relies upon are not reliable for assessing the current or future cost of CCS projects, and are insufficient to evaluate the current status of CCS development. EPA eliminated full capture CCS as the BSER on the sole basis that it would be too expensive (40 to 60% cost increase).[208] If the 40-60% increase was sufficient to eliminate full capture, then the 80+% increase experienced by active projects and estimated by DOE and others is **more than sufficient** to also eliminate partial capture as the BSER.

[207] 79 Fed. Reg. 1476 (January 8, 2014)
[208] 79 Fed. Reg. 1477. (January 8, 2014).

## Development Status of CCS Technologies



### G. EPA's evaluation of emission reductions fails to demonstrate that CCS is the BSER

The proposed rule cites Section 111(a)(1), along with Court determinations to note that "in considering the various factors and determining the 'best system,' the EPA must be mindful of the purposes of section 111, and the Court has identified those purposes as...reducing emissions as much as practicable."[209] EPA's consideration of emission reductions is flawed because the agency relies on ambiguous criteria to determine "as much as possible," fails to fully consider the magnitude of emission reductions that may be achieved from highly efficient processes alone, and utilizes loose, qualitative statements on CCS related emission reductions. EPA's determination that partial-CCS is the BSER from an emissions reductions perspective is based only on its qualitative assessment that CCS provides "significant" and "meaningful" reductions.[210] EPA provides no information on the baseline used to assess emission reductions and provides no information on the types of criteria considered in determining "significant" and "meaningful." Despite the "significant" and "meaningful" emission reductions that EPA expects will result, the agency notes that they "do not anticipate any notable $CO_2$ emission reductions associated with the rulemaking."[211]

### H. EPA fails to demonstrate that technology advancement will result from selecting CCS as the BSER

As part of the BSER analysis, EPA considered whether their determination would "promote the development and implementation of technology."[212] EPA concluded that establishing partial CCS as the BSER would "promote implementation and further development of CCS technologies"[213] and would "encourage continued research and development efforts."[214]

EPA is incorrect. AEP has provided comments on the magnitude of development challenges and the significant time and resources required to overcome these barriers. The technical, financial, and regulatory challenges to building new coal-based generation are daunting. Adding the challenges associated with integrating CCS, along with the uncertainty of whether compliance with the GHG NSPS is even achievable, creates an investment risk that no

[209] 79 Fed. Reg. 1463 (January 8, 2014)
[210] 79 Fed. Reg. For example 1436 related to use of the terms "meaningful" and "significant"
[211] 79 Fed. Reg. 1496. (January 8, 2014)
[212] 79 Fed. Reg. 1462. (January 8, 2014).
[213] 79 Fed. Reg. 1436. (January 8, 2014).
[214] 79 Fed. Reg. 1480. (January 8, 2014).

developer would accept. In effect, the proposed rule would prohibit the development of new coal generation, and in turn would negatively impact, if not halt entirely, any advancement in development of CCS technologies.

## IX. Other Considerations Demonstrate that Partial Capture CCS is not the BSER

### A. AEP's CCS Program demonstrates that CCS is not the BSER

From 2009 to 2011, AEP operated the first integrated CCS project in the world on a coal-based generation plant. AEP submitted extensive comments to EPA in 2012 that described the Mountaineer Plant CCS project, discussed lessons learned, and summarized key challenges for CCS to become a technically feasible and commercially viable technology. AEP's comments attempted to alleviate misconceptions by EPA in the 2012 proposed rule by placing into proper context the scope and outcome of its CCS program. Unfortunately, EPA ignored or gave negligible attention to those comments. The current proposed rule continues to misrepresent the scope, results, and lessons learned from the Mountaineer Plant CCS project. The following is another attempt to place the project into proper context in the hope that the comments will be fully considered as part of a fair, objective evaluation of CCS in the final rule.

AEP has been a strong advocate for the development and advancement of CCS technologies, and believes that technological solutions are critical to reducing emissions from and improving the performance and reliability of electric generation processes. Nonetheless, as an outcome of our first-hand experience and as reinforced by other public and private efforts, AEP is convinced that CCS is many years from being proved to be a technically feasible, adequately demonstrated, and commercially viable solution for reducing $CO_2$ emissions.

A number of qualifications must be made in order to properly understand what was and was not accomplished by AEP at the Mountaineer Plant. First, EPA claims that "[p]*rojects such as AEP Mountaineer have successfully demonstrated the performance of partial capture CCS on a significant portion of their exhaust stream*."[215] EPA's claim is misleading and inaccurate. AEP did not construct or operate a "partial capture CCS on a significant portion" of the Mountaineer Plant flue gas. AEP did successfully deploy a $CO_2$ capture system on a validation-scale slip-stream process (20 MW equivalent, or 1.5% of the Mountaineer Plant's 1,300 MW capacity). The success of that project was in proving that the technology was compatible with

[215] 79 Fed Reg. 1436 (January 8, 2014).

power plant conditions and that the technology could successfully capture $CO_2$ at a coal-fired power plant. The project *did not prove* that commercial-scale CCS is technically feasible or that it could be adequately demonstrated. AEP did consider a commercial-scale project, but after performing a front-end engineering and design ("FEED") study and being unable to obtain necessary cost-recovery approval from regulators, decided to cancel the project.[216] It should be clearly understood that the validation project *did not* constitute a commercial demonstration and that the technology *has not* been proven to be technically feasible or adequately demonstrated at a commercial-scale.

AEP partnered with Alstom to validate the chilled ammonia process for capturing $CO_2$ from the Mountaineer Plant. The validation-scale system was operated from September 1, 2009 through May 31, 2011. Over that period, the project captured more than 50,000 metric tons of $CO_2$. The system was built as a validation platform, with flexibilities for systematic process adjustments, which enabled operators to optimize and control all process streams and energy inputs to thoroughly evaluate the technology. Once completed, the AEP/Alstom team developed a comprehensive understanding of the chilled ammonia process and specifics about the operation of each system within the process. This background, including a detailed understanding of key process parameters, such as energy penalty, reagent loss, and $CO_2$ capture rate, facilitated moving forward with the FEED study for a commercial-scale project.

While the capture process was shown to be technically feasible under coal-fired power plant conditions, many important aspects of the technology must be demonstrated at full-scale (a minimum of approximately 250-MWe, or more than 12 times the size of the validation system at Mountaineer) before a process supplier or power plant owner could realistically consider deploying the technology commercially. For example, many post-combustion $CO_2$ capture technologies would use enormous quantities of steam in the process. If the steam is taken from the existing power plant boiler/steam-turbine system, then that represents a significant power generation heat cycle change, which requires a steam path redesign and modification of the generating unit. Once completed, the modifications intrinsically tie together the generating unit with the $CO_2$ capture system. Such a combination of systems has never been demonstrated and must be rigorously tested and optimized before the technology can be deemed reliable, proven,

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[216] The Final Technical Report for the commercial scale CCS project can be found at www.netl.doe.gov/technologies/coalpower/cctc/ccpi/bibliography/demonstration/ccpi_aep/MTCCS%20II%20Final%20Technical%20Report%20Rev1.pdf.

or commercially viable. In addition, the equipment to capture $CO_2$ is large and an entire system capable of treating the effluent of a power plant requires extensive tracts of land. In the AEP/Alstom study of a commercial scale installation, the system was designed to capture 265 MWe worth of flue gas (approximately 1/5 of the plant output), yet it occupied a footprint nearly the same size as the original power plant, or about 11 acres. Size alone would preclude use of the technology at many existing power plants and must be carefully considered in the design of any new power plant.

AEP also partnered with Battelle to study and validate sequestration of $CO_2$ into deep saline reservoirs near the Mountaineer Plant. Approximately 37,000 metric tons of the captured $CO_2$ was compressed and injected into two saline reservoirs located roughly 8,000 feet beneath the plant site. Besides two injection wells, one into each of the reservoirs, AEP deployed three deep monitoring wells at various distances from the injection point. Many experimental and novel monitoring technologies were also tested at the site. The difficult nature of the geology in the area proved some of these technologies to be inappropriate for the application. Again, while the project was successful in injecting and confining the $CO_2$ sent to the wellheads, the scale was far from being representative of what would be required for full-scale deployment. Furthermore, great uncertainty remains surrounding the liability for and future ownership of injected $CO_2$, which could dissuade any future developer. The experience of the AEP CCS program also identified a number of practical considerations that are significant barriers to any CCS project. These aspects are discussed in greater detail in Section C below

Of note, any commercial-scale CCS project is going to be very expensive. The commercial-scale CCS project that was considered for the Mountaineer Plant would have captured $CO_2$ from 20% of the flue gas. The conceptual project cost of $668 million escalated to approximately $1 billion after the FEED study was completed. These costs were expected to continue to escalate throughout the detailed engineering, construction, and commissioning phases of the projects. One cost that was not fully included in the $1 billion estimate relates to uncertainties on the cost to comply with requirements of the underground injection control (UIC) permit. Although the project was cancelled prior to even filing an application for a UIC permit, it was estimated based on the requirements in the Class VI UIC Guidelines that the project could have been required to install an additional 75 intermediate and deep monitoring wells alone at an estimated cost of nearly $300 million – a 30% increase in the estimated $1 billion CCS project – which again represents only 20% of the plant output!

A review and discussion of the lessons learned from the Mountaineer CCS Program were documented in a number of reports submitted to the Global CCS Institute ("GCCSI"). EPA is strongly encouraged to review and apply the information from these reports in the BSER evaluation for the final rule. All of these reports are readily accessible through the GCCSI website,[217] including the following:

- CCS Lessons Learned Report: AEP Mountaineer CCS II Project Phase 1[218]
- AEP Mountaineer II Project – Front End Engineering and Design (FEED) Report[219]
- AEP Mountaineer CCS Business Case Report[220]

EPA is also encouraged to review the draft Environmental Impact Statement for the Mountaineer commercial-scale demonstration project to gain greater perspective on the scope and magnitude of issues that any CCS project must address. It is especially revealing that these significant challenges are only for a 20% capture project. A requirement to capture 40%, 60% or more would create a level of barriers that would be too prohibitive for most, if not all, project developers to overcome. The draft EIS can be found on the DOE website.[221]

In conclusion, it is more accurate to state that the AEP Mountaineer project proved that the technology shows promise for future plant applications. However, technically feasible and adequately demonstrated CCS is still many years from being proven at a commercial scale, still requires development of an appropriate regulatory or legal framework, and, as a result, cannot yet be deemed as commercially viable technology.

### B. Numerous Public and Private Efforts demonstrate that CCS is not the BSER

Numerous assessments by public and private organizations recognize that CCS has not been proven to be technically feasible or adequately demonstrated for coal-based generation and that significant development barriers remain. For example, a November 17, 2011 Reuters article noted that "[then EPA Administrator Lisa] Jackson, whose agency looked at CCS as it developed

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[217] www.globalccsinstitute.com/search/apachesolr_search/AEP
[218] A copy is attached in Appendix C. (www.globalccsinstitute.com/publications/ccs-lessons-learned-report-american-electric-power-mountaineer-ccs-ii-project-phase-1)
[219] www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report
[220] www.globalccsinstitute.com/publications/aep-mountaineer-ccs-business-case-report
[221] http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0445-DEIS-01-2011.pdf

the rules, said the technology has long way to go. 'It can be years, maybe a decade or more, until we have the technology available at a commercial scale,' she said."[222]

These assessments consistently conclude that the current scope and progress of CCS development programs are insufficient to drive the near-term completion of commercial-scale CCS projects whose operating experience is needed to adequately demonstrate the technology. In fact, most of the studies indicate that technically feasible and adequately demonstrated CCS technologies are *at least* a decade or more away, *even if* much more ambitious RD&D programs were implemented. EPA ignores these studies and assessments in the proposed rule, although it is noteworthy to reiterate that these are the type of "major assessments" that EPA has described as being of significant value for evaluating complex issues and for informing the Administrator's "best judgment."[223] Appendix B summarizes a portion of these studies and major assessments to highlight the actual state of CCS development, to identify the magnitude of development that remains for the technology to be adequately demonstrated, and to further indicate that CCS is not the BSER for coal-based generating units.

### C. Practical development considerations demonstrate that CCS is not the BSER

The prior comments were provided to critically evaluate specific aspects of the EPA BSER analysis. Apart from those comments and outside the complex dialogue on issues such as the interpretation and application of NSPS regulatory requirements, a host of practical considerations to CCS development exist that represent significant challenges to any CCS project. In many cases, these practical considerations are more of a barrier to the adequate demonstration and commercialization of CCS.

#### 1. CCS is not just another control technology

The scope and complexity of development issues for CCS are dramatically different than for other emission controls, such as flue gas desulfurization ("FGD") or selective catalytic reduction ("SCR") technologies. Shoehorning the development of CCS into the "typical" development curves of FGD or SCR technologies is an imperfect comparison that produces a false perception of the steps and timeline for CCS development and in no way establishes the standard for or offers guarantees on the success of CCS development.

[222] www.reuters.com/article/2011/11/17/usa-epa-carbon-idUSN1E7AG0WU20111117
[223] See Section VIII.A for AEP comments related to the use of "major assessments."

The CCS development challenges at coal-based power plants are unique from other technologies and are not one-size-fits-all for all potential projects. This is attributed to a greater complexity of process integration issues, the magnitude of operational considerations, and the significant increases to cost of electricity production. CCS also presents unique issues regarding the enormous amounts of $CO_2$ byproduct that must be handled, transported, and stored in geologic formations. For example, coal-combustion ash and FGD-related by-products are solid materials that can be handled and stored in a landfill, while $CO_2$ is generally captured and compressed to a supercritical liquid, which must be stored in deep geologic formations, and will be subject to a more extensive, diverse, and in many cases undeveloped set of regulatory and legal requirements. EPA has acknowledged in their guidance document for PSD permitting for GHG's that the scope of design, construction, and operation considerations are much different and unique for CCS compared to other emission control systems by noting:

> "*EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage.*"[224]

2. The cost of commercial-scale CCS remains a significant unknown

Regardless of whether the current state of CCS development is characterized as first-of-a-kind, $n^{th}$-of-a-kind, or something in between, the cost of the technology is very expensive, which has restricted and, in many cases, prohibited, development. Each example of a potential commercial-scale CCS on a coal-based generating unit has experienced a significant escalation in costs. The wide disparity in the cost estimates of current efforts is indicative that CCS is not a one-size-fits-all technology, that project-specific cost drivers are significant, that reliable estimates of CCS costs are evolving, and that future CCS cost are highly speculative.

3. The energy required to power CCS systems is large and represents a significant development challenge

The energy demand and parasitic load to power CCS systems is significant. As noted by the Department of Energy:

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[224] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." (Mar. 2011). p. 36. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

"*The combined effect of steam and auxiliary power required to operate the $CO_2$ capture and compression systems is that the net power output of the unit would decrease by approximately 30 percent*"[225]

The significant energy requirements for CCS systems have been widely recognized and reported by others as well, including in a report by The U.S. Government Accounting Office:

"*Current CCS technologies require significant energy to operate... Parasitic loads...for current CCS technologies are estimated to be between about 21% and 32% of the plant output for post-combustion* [capture systems]"[226]

For context, assume that a CCS system installed on 600 MW coal-based power plant would require 30% of the load to operate, or approximately 180 MW. The electricity required to capture $CO_2$ from this 600 MW unit is equivalent to the annual electricity consumed by nearly 125,000 households.[227] If the purpose of the power plant in the example is to meet a customer demand of up to 600 MW, then the plant would have to be oversized to accommodate the large CCS-related auxiliary load or a separate generation source would be required.

Increasing the size of the unit would result in greater coal consumption, greater water usage, and greater emissions, byproducts, and water discharges to power the CCS system. The NRG Parrish CCS project is using an approach whereby a separate 80 MW natural-gas fired combustion turbine unit has been constructed for the purpose of powering the carbon capture system.[228] In other words, a separate, uncontrolled $CO_2$ emission source is being constructed to power equipment that will capture $CO_2$ emissions from another combustion source that will then be used for producing oil that will eventually be combusted and result in more, uncontrolled $CO_2$ emissions.

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225 DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap. (Dec 2010). p.26
226 "Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions." U.S. GAO. (Jun 2010).
227 Assumes 85% capacity factor of plant and average residential demand of 10,873 kw/yr (per EIA www.eia.gov/tools/faqs/faq.cfm?id=97&t=3);
228 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project.

Based on the estimates calculated below, this type of configuration would actually result in more $CO_2$ to the atmosphere than if the unit was left uncontrolled!

| | |
|---|---|
| New $CO_2$ Emission from Operation of $CO_2$ Capture & Recycle Facility (new combustion turbine) | = +710,000 tonnes/yr[229] |
| $CO_2$ Captured from Coal Unit | = -1,500,000 tonnes/yr[230] |
| Estimate Barrels of Oil from Injected $CO_2$ | = 3,750,000 barrels/yr[231] |
| Estimated $CO_2$ from Combustion of Recovered Oil | = +1,612,500 tonnes/yr[232] |
| **Net $CO_2$ Emissions from Project = +710,000 – 1,600,000 + 1,612,500** | **= +722,500 tonnes/yr** |

It is clear from an objective accounting of $CO_2$ emissions in this example that CCS provides few, if any, meaningful emission reductions. It is also clear that significant development is needed to reduce the energy demand of $CO_2$ capture systems before CCS can be legitimately considered as technically feasible or adequately demonstrated.

4. Integration of CCS and coal-based generation technologies introduces unique development challenges

The integration of CCS systems to coal-based generation technologies introduces a number of unique development challenges that include:

- Integration of Operating Philosophies: The use of CCS represents the integration of two different operating philosophies: power plant vs. chemical plant. Power plant systems are designed to accommodate dynamic operating scenarios where processes routinely cycle in different modes depending on variables such as changes in electricity demand or fuel characteristics. Chemical plants, which closely resemble $CO_2$ capture processes, are typically designed for steady-state operations with process inputs that have fixed quantities and rigid purity specifications. Integrating these philosophies at a commercial-scale presents significant engineering and design challenges whose solutions have yet to be adequately demonstrated as technically feasible or cost effective.

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229 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project. (p 30905)
230 Id
231 Based on EOR rate of 1 barrel per 0.40 $CO_2$ tonnes injected. "Enhanced Oil Recover & CCS." Carter, L. US Carbon Sequestration Council. (Jan 14, 2011)
232 Based on $CO_2$ emission factor of 0.43 tonnes $CO_2$/barrel of oil combusted. www.epa.gov/cleanenergy/energy-resources/refs.html (accessed Feb 21, 2014)

- Capture System Design Specifications: Certain capture systems have stringent process chemistry requirements that demand pristine flue gas conditions that in some cases are well beyond the capability of state-of-the-art flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems. For such systems, additional flue gas polishing systems would be required to accommodate the capture process.

- Capture System Power and Steam Requirements: Energy consumption requirements by the capture system represent the most daunting barrier to economical CCS deployment. Current estimates are that operation of the CCS system would demand 30% of the net output from the generating unit.[233] Some capture systems are also designed to consume large amounts of steam, which also impact overall unit performance and efficiency. The large energy and steam requirements for certain systems to operate capture systems introduces unprecedented engineering and operating challenges to integrate these systems into power plant designs and process flow schemes.

- Footprint of Capture System: The size of the capture systems is a concern as current design configurations would more than double the footprint of a typical power plant, which introduces substantial implications with respect to land availability, constructability, and project costs. For example, the capture system for the AEP commercial-scale Mountaineer Plant CCS project would have encompassed over 13 acres, which is over double the size of the generating unit itself. Notably, the footprint for the Mountaineer Plant capture system was for a system designed to capture only 20% of output from the unit! While some economies of scale would be expected through process and design optimization, the capture system footprint will remain very large. The large footprint is also another example of the magnitude and complexity of equipment and systems within the capture process, which introduces significant performance and reliability challenges. In other words, more equipment and area introduces greater operational risks. The figure below illustrates the scale of

[233] DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap. (Dec 2010). p.26

the capture system that was being planned for the 20% $CO_2$ capture system at the Mountaineer Plant.

Mountaineer 1300 MW Power Block

SOx / NOx / PM Controls

20% CCS System

- Unit Availability Risks from Geologic Storage and EOR Processes: Operation and performance risks specific to the geologic storage or EOR systems introduces integration concerns as these risks can impact the performance or constrain the operation of the capture system and power plant. For example, a CCS project aligned with an EOR system would be constrained by the assurance that the demand for $CO_2$ from the EOR operator always meets or exceeds the $CO_2$ produced by the power plant. When, not if, but when the demand for $CO_2$ from the EOR operator is insufficient, then the power plant would be forced vent captured $CO_2$ to the atmosphere, curtail operations or shutdown. Power plants are developed, and in many states are regulated, on the basis of being able to reliably meet a specified demand for electricity – an essential public need. Subjecting the availability of power generation to the availability to EOR operations fails to ensure that the obligation to provide reliable power can be met. Likewise, similar constraints are reasonably to be expected to occur with geologic storage systems where a host of known and unknown variables could constrain the availability and performance of injection wells. AEP experienced these types of constraints during the operation of the validation-scale CCS project. The scope of these risks coupled with a number of legal and regulatory uncertainties associated with long-term geologic storage is another indication that CCS has not been adequately demonstrated to be technically feasible or commercially viable.

5. Undeveloped regulatory and legal considerations may alone prohibit the development and adequate demonstration of CCS projects

A broad scope of legal and regulatory uncertainties exist that apply to each aspect of the CCS process (capture, transport, and storage), which must be addressed before any CCS project can be developed. A discussion of these issues follows to provide context on the breadth of issues that remain to be resolved and to demonstrate the significant challenge that these issues pose to CCS development. Unknowns exist regarding how these issues will be addressed within state boundaries, and also with respect to interstate considerations. A recent study by the West Virginia Chamber of Commerce surveyed all 50 states to assess the readiness of their state regulations and policies to accommodate CCS projects. Most states are not well prepared and are not proactively preparing programs to regulate CCS projects, as summarized below:[234]

| | Obtained UIC Class VI Permitting Primacy | Identified Property Rights to be Secured | Streamlined procedures for the taking, unitization or use of property rights | Addressed Long-term Care Provisions | Streamlined procedures for the siting or construction of CO2 pipelines |
|---|---|---|---|---|---|
| States that responded yes | 0 states (0%) | 14 states (28%) | 8 states (16%) | 12 states (24%) | 11 states (22%) |

The development challenges related to legal and regulatory issues have been recognized in many assessments, including the following:

[234] "A State-by-State Survey of Existing Statutes and Rules Related to the Transportation and Geologic Storage of Carbon Dioxide" (March 20, 2014). West Virginia Chamber of Commerce. EPA Docket ID: EPA-HQ-OAR-2013-0495-4733

- The Interagency Task Force on CCS, which concluded that "for widespread cost-effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship" and that "regulatory uncertainty has been widely identified as a barrier to CCS deployment."[235]

- The Secretary of Energy's National Coal Council, which determined that "[t]he management of long-term liability risks is [a] critical consideration for CCS projects...[U]ncertainty regarding long-term liability options remains a challenge."[236]

- A 2011 study from the Harvard Kennedy School's Energy Technology Innovation Policy Research Group, which found that for the commercial-scale CCS demonstration projects in Phase III of the DOE's Regional Carbon Sequestration Partnerships Program, "[l]iability for sequestration of $CO_2$ and lack of coordination among regulatory authorities" would pose "significant barriers."[237]

- A 2014 report by the Congressional Research Services noted that: "Development Phase projects will provide a better understanding of regulatory, liability, and ownership issues associated with commercial scale CCS. These nontechnical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting $CO_2$ safely and in perpetuity are resolved."[238]

*a.* *<u>EPA has ignored property rights issues that are barriers to the adequate demonstration and development of CCS</u>*

In addition to the significant technical and financial challenges related to geologic sequestration, equally significant legal and regulatory challenges exist in regards to the ownership, access, and use of the geologic area (e.g. pore space) for the storage of $CO_2$. Key questions related to property rights, many of which remaining to be resolved, include:

- Who holds ownership rights to pore space? Surface-owner, mineral rights-owner, state or Federal government, other;
- Does surface or mineral-rights ownership mean owners have a protectable interest?[239]
- To the extent that protectable interests exist, are those interests limited to within a specific depth below the surface of the earth?[240]

[235] Report of the Interagency Task Force on Carbon Capture and Storage, pp. 10-14 (Aug 2010).
[236] Expediting CCS Development: Challenges and Opportunities, p. 83 (Mar 2011).
[237] Craig A. Hart, Putting It All Together: The Real World of Fully Integrated CCS Projects, Discussion Paper 2011-06, Belfer Center for Science and International Affairs (Jun 2011) available at http://belfercenter.ksg.harvard.edu/files/Hart%20Putting%20It%20All%20Together%20DP%20 ETIP%202011%20web.pdf).
[238] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service. p. 23
[239] "A State-by-State Survey of Existing Statutes and Rules Related to the Transportation and Geologic Storage of Carbon Dioxide" (Mar 20, 2014). West Virginia Chamber of Commerce. p. 10. EPA Docket ID: EPA-HQ-OAR-2013-0495-4733

- Does the use of pore space necessitate the need acquire access or pore space rights?
- How are pore space rights acquired?
- How do existing programs for eminent domain, unitization, public use, or voluntary acquisition translate to pore space acquisition?[241]
- How does existing eminent domain authority apply to $CO_2$ pipeline development?
- What is the relationship between the use of pore space for $CO_2$ sequestration and liabilities related to the ownership and use of surface or mineral rights?
- Who has regulatory jurisdiction over issues related to property rights? State utility commissions, state environmental protection agencies, state natural resource departments, etc.

A number of options have been identified for resolving these issues. Addressing each will require time and resources, but most importantly will require a desire by individual states to proactively resolve these issues and to become prepared to efficiently and effectively regulate future CCS projects. Without these steps, such regulatory and legal issues will remain significant barriers to CCS development.

*b.* *EPA has ignored long-term stewardship and liability issues, which are barriers to the adequate demonstration and development of CCS*

Considerations related to the long-term care of $CO_2$ that has been geologically sequestered focus on two key issues: stewardship and liability. Stewardship involves the monitoring and assessment of the geologic storage area, while liability relates to responsibility after closure of the injection process. Although the EPA Class VI injection well regulations establish monitoring and post-injection site care requirements for a specified period (50 years post-injection), a number of uncertainties during and beyond that period remain that must be addressed, including:

- Post-closure requirements for transfer of liability? The federal government and many states have yet to provide a mechanism for the transfer of liability.[242]
- Financial responsibility requirements to assure the availability of funds for the life of the project (including post-injection site care and emergency response)? EPA Class VI rules include some requirements, but how far do these extend into the future?
- Post-closure monitoring requirements? EPA Class VI rules have some requirements, but how far do these extend into the future?

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[240] Id. p. 11.
[241] Id. pp. 18-19.
[242] Id. pp. 32-33.

c. *<u>The EPA Class VI UIC permitting process and requirements introduce uncertainties that are a barrier to the adequate demonstration and development of CCS</u>*

The permitting program for the EPA Class VI underground injection control (UIC) program is in its infancy. A handful of states are pursuing primacy over the permitting process, but none have obtained it. Currently, EPA has primacy over the permitting process in all states.[243] To date, EPA has not issued a single final Class VI permit.[244] The application process is extensive and requires information to be provided that will be very time-consuming and expensive to obtain – if indeed it is even obtainable given the size of the area that must be considered to accommodate the volume of $CO_2$ storage associated with a coal-based generation unit. For example, the Class VI permit must include information such as:

> "*A map of the injection well...and the applicable area of review. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads*."[245]

As the area of review is likely to be many tens of square miles in size for a commercial-scale project, the research and preparation of such information alone will be tedious and time consuming process that will result in a voluminous submittal the regulatory agency for review. It is to be determined whether the application process itself represents a critical barrier in the development of CCS. Another unknown that remains is how the extensive information provided in the application will translate into the actual permit requirements and whether such requirements would be so onerous to comply with that they could effectively prohibit a CCS project from occurring. For example, based on information in EPA's final Class VI UIC rule regarding the number of monitoring wells that may be necessary,[246] the commercial-scale CCS Mountaineer project could potentially have been required to install an additional 75 monitoring wells at an estimated cost of nearly $300 million, which represents a 30% increase in the estimated $1 billion CCS project cost – again this is for the geologic storage of only 20% of the

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[243] Id. pp. 6-10.
[244] "U.S. EPA Seeks Public Comment on Proposed Sequestration Permits in Central Illinois." (Mar 31, 2014). EPA Press Release.
[245] 75 Fed. Reg. 77292. (Dec. 10, 2010).
[246] 75 Fed. Reg. 77279-77280. (Dec. 10, 2010).

plant output! These types of unknowns represent significant challenges to the adequate demonstration and development of CCS.

In addition to the time required to prepare the Class VI UIC permit application, the time required for the regulatory agency to process the application and issue a final permit represents a significant development hurdle as well. Archer Daniels Midland filed the very first Class VI UIC permit applications to U.S. EPA, one in July 2011 and one in December 2011. Nearly three years later, both applications remain under technical review by U.S. EPA. Remaining steps for processing these applications include the issuance of a draft permit, public commenting period, further technical review and issuance of a final permit.[247] These steps could easily increase the permitting by years. Any potential project cannot move forward with detailed engineering and design, or construction without the necessary regulatory approvals (e.g. UIC permit) in place and without the certainty that related regulatory requirements will be obtainable, cost-effectively, and achievable throughout the operation of the facility. For example, a permitting process that requires five years or more to obtain a final permit is likely to be prohibitive to any future project that must rely on CCS technology.

Finally, the Class VI UIC regulation should not be misconstrued as having addressed all barriers to the geologic sequestration of $CO_2$. As noted in a 2014 report by the Congressional Research Service:

> "*The development of the regulation for Class VI wells highlighted that EPA's authority under the SDWA is limited to protecting underground sources of drinking water but does not address other major issues. Some of these include the long-term liability for injected $CO_2$, regulation of potential emissions to the atmosphere, legal issues if the $CO_2$ plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected $CO_2$ plume, and ownership of the subsurface reservoirs (also referred to as pore space)*."[248]

*d.* *<u>EPA ignores interstate and comingling issues that are barriers to the adequate demonstration and development of CCS</u>*

While the aforementioned questions show how far individual state requirements must mature to be able to accommodate CCS within state boundaries, another layer of complexity occurs when these questions are considered in context with interstate boundaries or with the comingling of geologically stored $CO_2$ from multiple sources. The relationship between

[247] www.epa.gov/region5/water/uic/adm/index.htm (Accessed March 3, 2014)
[248] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" (Feb 10, 2014). Folger, P. Congressional Research Service. p. 23

individual state regulations on property rights, long-term stewardship and liability, and permitting has, in most cases not yet been determined for individual injection wells. Likewise, these issues need to be resolved to address the intrastate or interstate geologic storage of $CO_2$ from one source that over time combines with the $CO_2$ stored by another source.

*e.* *<u>Uncertainties regarding the applicability of RCRA regulations remain a barrier to CCS development</u>*

EPA has conditionally excluded $CO_2$ streams captured from power plants and industrial systems as a hazardous waste under the RCRA program if they are injected under a UIC Class VI permit. However, uncertainties remain regarding the extent of that exemption, which could actually discourage the use of anthropogenic $CO_2$ for EOR operations. Although EPA notes in the final rule revising the RCRA requirement that the injection of $CO_2$ for EOR or other commercial purposes "would not generally be a waste management activity," questions remain regarding RCRA applicability when the EOR process ends or if the process becomes solely a geologic storage operation.[249]

6. <u>Geologic storage may be the greatest challenge to the adequate demonstration and development of CCS</u>

The complexity technical and financial uncertainties and concerns related to geologic storage are significant, and may represent the greatest barriers to the technical feasibility, adequate demonstration and commercialization of CCS. The availability of suitable saline formations, geologic injection pressure limitations, and the ultimate storage capacity of formations, as well as monitoring and verification methods are all currently the subject of intense study and lack large-scale data for proof-of-concept soundness. Unfortunately, EPA greatly downplays and ignores most of these issues in their BSER analysis.

A primary concern is with understanding the geology itself where characteristics may be highly variable even within a close area; where techniques to assess these characteristics are expensive and time consuming to perform; and where resources to evaluate such data through modeling or other means may not be able to adequately or reliably assess underground conditions. Consider, for example, the efforts to access the geology near the AEP Mountaineer Plant. From 2003 to 2007, over $7.5 million was spent to perform extensive surface and subsurface testing, including modeling and analyses, to characterize the geology near the plant

[249] 79 Fed. Reg. 355 (January 3, 2014).

and to assess its feasibility for $CO_2$ storage. Results provided sufficient information to support the development of the validation-scale[250] CCS project at the Mountaineer Plant. The validation-scale project included the development of additional wells for $CO_2$ injection and for monitoring purposes. Geologic data from characterization of these wells and the experience gained from operations greatly expanded the knowledge-base of the geology near the Mountaineer Plant.

Despite this extensive geologic knowledge obtained beginning with the initial characterization in 2003 and carried through the operation and monitoring of the validation facility, the information was insufficient to evaluate the geology and design the injection wells associated with the planned commercial-scale CCS program. Prior to the commercial-scale program being discontinued, one additional geologic characterization well was drilled approximately 3 miles from existing wells at the site. Even at this short distance, changes in the geologic characteristics were being noted that would have required a number of additional characteristic wells to be drilled had the project moved forward. At a cost of approximately $5 million per well and over 6 months to obtain the well works (drilling) permit, environmental-related permits, and conduct the drilling, obtaining these additional characteristics is not a small undertaking. Another potential concern is the availability of drilling contractors, in which a high demand exists by industries that are developing oil and gas resources. The opportunities from other industries can provide greater revenue potential and with less scrutiny. As one driller noted during the Mountaineer CCS Program, the demand for safety and environmental excellence by AEP, and presumably by other utilities, far exceeded that required by other industries and would not interest many potential drilling companies, especially if greater profits are available from those industries.

In addition, technologies to monitor and verify the location of the injected $CO_2$ are needed, whose capabilities, performance, and durability have not yet been proven for such applications. While experience from the oil exploration and production industries is beneficial, it is not a substitute for the lessons learned from operating a sufficient number of large-scale demonstration projects involving the injection of $CO_2$ in saline and other formations. Separately, a demand for more reliable geologically-based computer models remains, which, in part, requires a time-consuming, expensive, and rigorous validation process. If proven, these models could

[250] The AEP Mountaineer validation-scale project was designed to capture $CO_2$ from only 1.5% of the flue gas. It was not a commercial-scale project.

potentially be used to avoid exorbitantly high costs of installing and operating large numbers of monitoring wells, which otherwise may prohibit CCS development.[251]

The experiences of the Mountaineer CCS program are a further indication of the complexity at every level of developing injection wells in regards to technical, financial, and schedule risks. In the proposed rule, EPA seems to recognize this complexity by noting that:

> "*Geologic storage potential for $CO_2$ is widespread and available throughout the U.S...., each potential geologic sequestration site must undergo appropriate site characterization to ensure that the site can safely and securely store $CO_2$.*" (emphasis added)

and

> "*While EPA has confidence that geologic sequestration is technically feasible and available, EPA recognizes the need to continue to advance the understanding of various aspects of the technology, including, but not limited to, site selection and characterization, $CO_2$ plume tracking and monitoring.*" (emphasis added)

Despite this recognition, the agency fails to properly account for these design and development barriers in their evaluation of CCS as the BSER. Had EPA objectively considered the significant technical, financial, and practical barriers to the design of geologic storage areas, it would be clear that CCS is not the BSER.

7. $CO_2$ pipeline development presents challenges to the adequate demonstration and development of CCS

EPA gave minimal consideration to issues related $CO_2$ pipeline development. However, these issues pose a number of schedule, cost, and regulatory uncertainties that can be significant enough to eliminate the prospects of any CCS project. AEP experienced some of these pipeline development challenges in the initial design phase alone. For the commercial-scale (20% capture) Mountaineer Plant CCS project, AEP considered pipeline routes to potential injection wells located within 12 miles of the capture process. A common perspective is that pipeline routes could "simply" parallel existing transmission rights-of-way. AEP considered this option and found that it was anything but "simple." For example, existing transmission rights-of-way are commonly specific to above ground structures and would not apply to pipeline development. Further, existing rights-of-way do not always provide access to perform work that is not affiliated with the transmission lines.

[251] For example, it has been estimated that a cost risk of approximately $300 million may have been required to install the monitoring wells associated with a UIC Class VI injection well permit for the cancelled Mountaineer CCS Project that would have captured $CO_2$ from 20% of the flue gas.

This was the case for the AEP commercial-scale CCS project that planned to develop pipelines along existing transmission line corridors. In order to access potential pipeline routes for a visual assessment alone required obtaining additional rights-of-entry permissions from landowners. This additional permission was also necessary to perform baseline field studies (biological, cultural, and wetland) that were needed to develop applications for permits needed to facilitate construction. Obtaining this access was an onerous undertaking that increased the project cost and development timeline as over 250 landowners were involved. That process first involved extensive title searches to identify landowners, followed by an extensive outreach to contact landowners, who included local residents, businesses, out-of-state descendants, or yet-to-be probated estates. Many refused to grant access or did so after much inquiry. But this process reveals the complexity of what otherwise should have been a straight-forward and benign request – to *qualitatively* survey the existing transmission line right-of-way for a *potential* $CO_2$ pipeline and nothing more. Separate permissions would have had to be obtained to actually construct the pipeline, which undoubtedly would have been more challenging.[252] For capture projects that require much longer pipeline transport to access geologic storage or EOR systems, a developer would have obtain rights of way from potentially thousands of landowners and obtain permits from multiple jurisdictions, including multiple states. The scale of this effort would dwarf the aforementioned pipeline development challenges for the Mountaineer Plant CCS project.

Several entities have evaluated the cost for $CO_2$ pipeline development – and the estimates are staggeringly expensive. For example a 2007 Duke Energy study estimated that to construct a $CO_2$ pipeline along existing right of way from North Carolina to sites in the Gulf States and Appalachia would approach $5 billion. Separately, the International Energy Agency concluded that a 50% reduction in $CO_2$ emissions by 2050 would require an investment of nearly $300 billion to construct necessary pipelines to transport the $CO_2$ from capture to end use facilities.[253]

Another consideration with pipeline development is that its siting and design are dependent on the siting and design of the $CO_2$ injection wells. As discussed above, the site characterization, design, and permitting of the injection wells is also a time consuming process with considerable unknowns. Even though some preliminary pipeline development activities can

[252] "Bad Gas Policy." Peltier. R. Power Magazine. (Jul 2011). p. 6
[253] Id.

occur prior to and in parallel with the development of the injection wells, final pipeline design, permitting, and construction requires certainty on the location of the wells.

These types of challenges underscore the point that development of $CO_2$ transport systems will add significant scope, time, and cost to any CCS project. Although EPA ignores these challenges in the proposed rule, the impact of these risks should be evaluated in the final rule as EPA considers the overall feasibility and costs of CCS development.

8. <u>Enhanced oil recovery offers no guarantee as being available or willing to support $CO_2$ capture processes from coal-based generating units</u>

The EPA "*anticipates that many early geologic sequestration projects may be sited in active or depleted oil and reservoirs*" and that "*opportunities to utilize $CO_2$-EOR operations for geologic storage will continue to increase.*"[254] The agency also "*expects that for the immediate future, captured $CO_2$ from affected units will be injected underground for geologic sequestration at sites where EOR is occurring*."[255] The viability of these opportunities, however, faces many challenges, including those associated with the validation and accounting for $CO_2$ storage permanence. Current and past EOR practices have not been required to demonstrate permanent $CO_2$ storage. In some cases, EOR operators have been economically driven to minimize the quantity of $CO_2$ left underground in favor of reusing the injected $CO_2$ in other recovery operations. EPA also alludes to the lack of integrated power plant and EOR operating experience by noting that the "$CO_2$ supply for EOR operations currently is largely obtained from natural underground formations or domes that contain $CO_2$."[256] While EPA is optimistic that EOR applications will be the storage option of choice for future generators, the potential opportunities may be limited due to the proximity of EOR opportunities and the willingness of EOR operators to accept the operational risks and increased regulatory burdens that may come with the use and accounting of injected $CO_2$.

EOR operators are in the business of one thing – timely and cost-effectively producing hydrocarbons. They are not in the business of providing reliable, affordable electricity. They are not in the business of playing an integral role in the definition of a best system of emission reductions for another industry. EOR processes operate when and how they want to operate, outside the influence of electricity demand, power prices, or generation outages. EOR operators

[254] 79 Fed. Reg. 1474. (January 8, 2014)
[255] 79 Fed. Reg. 1482. (January 8, 2014)
[256] 79 Fed. Reg. 1474. (January 8, 2014)

are only one component of a larger industry – an industry where competition and opportunities for development continue to expand, especially with the growth of hydraulic fracking and shale-gas extraction techniques. In other words, if the power industry through the use of carbon capture systems is able to provide another supply of $CO_2$ to support EOR operations that is cost-effective, then EOR operators *may* be willing use it. But it is not as if EOR operators are waiting in neutral or anxiously anticipating the possibility that power generation-derived $CO_2$ will become available, especially if the timetable for that availability is a significant unknown.

AEP has observed this type of ambivalence of one industry to another in working through the complex process of obtaining permission from coal companies to able to drill characterization, injection, and monitoring wells in support of the Mountaineer Plant CCS program – a program that could help lead to the continued use of the very product that such companies are producing, coal. In this example, the mineral rights below the surface of planned wells were owned by a coal company. Permission had to first be obtained from the owner to drill through the recoverable mineral, coal, before a well works (drilling) permit could be issued. Such permission was difficult to obtain and is another challenge to CCS development.

Regulatory challenges for EOR operators may be significant as well. Consider the October 2013 comments from U.S. EPA on the draft environmental impact statement for the proposed Hydrogen Energy California IGCC/CCS project. EPA's comments note that:

> "*According to the PSA/DEIS, hundreds of wells have been installed in the Elk Hills Oil Field for injection and production over the decades of petroleum extraction activity, as well as the thousands of well bores that abound in the site for different purposes and at varying depths of penetration... It indicates that the presence of such a large number of well bores in the seismically active project site creates a potential for leak pathways of injected $CO_2$... CEC staff recommends that HECA enter into an agreement with OEHI to require installation of a robust monitoring network capable of detecting leaks.*
>
> [EPA] *Recommendation: To the extent practicable, efforts should also be made to locate and permanently seal old wells that could provide a conduit for $CO_2$ leakage*."[257]

The prospect of being required to locate and permanently seal "hundreds of wells" and "thousands of well bores" is simply not practical, far outside the typical scope of EOR operations, and alone would likely doom any CCS project from being developed. As noted in the comments above, the EPA Class VI UIC permitting experience to date indicates that the

[257] U.S. EPA Region IX Comments on Preliminary Staff Assessment/Draft EIS (CEQ#20130210) for HECA project. (October 24, 2013) . p. 12

process is time-consuming and the outcome of requirements is wrought with uncertainties. The time to obtain a Class VI UIC permit, perform detailed engineering and design, and construct a new fossil fuel-fired power plant equipped with CCS will encompass many years, and could easily require five to seven years or more. Aligning such a lengthy and uncertain development time frame with the business plans of an EOR operator represents a significant challenge to any CCS project. EPA has been extremely naive in assuming that the EOR experience to date could readily accommodate the requirement to install CCS technologies on fossil-fuel based generating units. For example, as EPA notes in the proposed rule:

> "*A recent study by DOE found that the market for captured $CO_2$ emissions from power plants created by economically feasible $CO_2$-EOR projects would be sufficient to permanently store the $CO_2$ emissions from 93 large (1,000 MW) coal-fired power plants operated for 30 years*."[258]

Such optimism clearly escapes another DOE report that indicates the EOR experience to date cannot be assumed to be sufficient to readily accommodate regulated CCS technologies. This report was authored by Dr. James Dooley and others at the Pacific Northwest National Laboratories ("PNNL") – the same author and organization that prepared a separate evaluation of CCS, which EPA draws upon in the technical feasibility portion of their BSER analysis. Several statements in the PNNL EOR report are particularly noteworthy and suggest that EOR opportunities are not readily available to support power plant CCS systems, including:[259]

- "*$CO_2$-EOR as commonly practiced today does not meet the emerging regulatory thresholds for $CO_2$ sequestration, and considerable effort and costs may be required to bring current practice up to this level*." (p. 5)
- "[O]*ur research suggest that $CO_2$-EOR is dissimilar enough from true commercial-scale CCS – the vast majority of configurations likely to deploy – that it is unlikely to significantly accelerate large scale adoption of the technology*" (p.3)
- "*The paper concludes....that estimates of the cost of $CO_2$-EOR production or the extent of $CO_2$ pipeline networks based upon this energy security-driven promotion of $CO_2$-EOR do not provide a robust platform for spurring the commercial deployment of carbon dioxide capture and storage technologies (CCS) as a means of reducing greenhouse gas emissions.*" (p. 2)
- "*The authors remain skeptical of arguments for expanded $CO_2$-EOR that are, at their core, extrapolations of what happened in the past in an effort to address energy*

[258] 79 Fed. Reg. 1474. (January 8, 2014)

[259] "$CO_2$-driven Enhanced Oil Recover as a Stepping Stone to What?". Dooley, et.al. Pacific Northwest National Laboratory. (July 2010). PNNL-19557.

*security concerns, a fundamentally different motivation than stabilizing atmospheric concentrations of GHGs*." (p.16)

- "*The vast majority of $CO_2$-EOR projects inject $CO_2$ produced from natural underground accumulations; in the U.S. and Canada, naturally-sourced $CO_2$ provides an estimated 83% of the $CO_2$ injected for EOR*" (p. 4)

- "*The requirements necessary to qualify $CO_2$-EOR as a geosequestration project are not trivial and involve significant work and cost throughout each state of the project*." (p. 10)

- "*The fact that only one of the 129 current $CO_2$-EOR projects worldwide is regarded or certified as a CCS project, and only 1 of the 4 current commercial CCS projects utilizes the $CO_2$-EOR process, provide significant empirical evidence that $CO_2$-EOR is not a mandatory step on the path to CCS deployment*." (p. 27)

Separately, the proposed rule relies upon current GHG reporting programs to help demonstrate compliance. The reporting tools upon which EPA is relying have never been used. For calendar year 2012, only two facilities submitted any information to EPA's GHG Reporting Program for carbon injection activities.[260] Both of these facilities have been granted research and development exemptions for GHG reporting, and both of them reported only the volume of GHGs received at the facility under subpart UU, not the detailed information required by subpart RR. There were no estimates of the amounts of GHGs actually successfully sequestered, and neither facility has developed the kind of monitoring protocols required under subpart RR. The remaining facilities listed in EPA's reporting tool are only subject to subpart UU, and are only required to report volumes of "new" $CO_2$ received at the facility, not the amounts that are used in, recovered, and recycled through EOR or other operations, nor any amounts that may be emitted from those operations. As a result, no useful information about the actual amounts of $CO_2$ in recovered oil and gas, or emitted to the surface in connection with an EOR operation, has ever been submitted to EPA. Indeed, based on the 2012 reports, it appears that the other 85 facilities listed as being subject to subpart UU required no "new" $CO_2$ for their operations during the entire year, leading one to question the availability of EOR opportunities for the large amounts of $CO_2$ that would be captured at even a single, partially controlled coal-fired steam generating unit. EPA therefore has no basis for its assumptions regarding the availability of

[260] www.epa.gov/climate/ghgreporting/ghgdata/reported/index.html

sequestration at EOR operations, or the ability of such operators to successfully design a monitoring program that would meet the requirements of subpart RR.

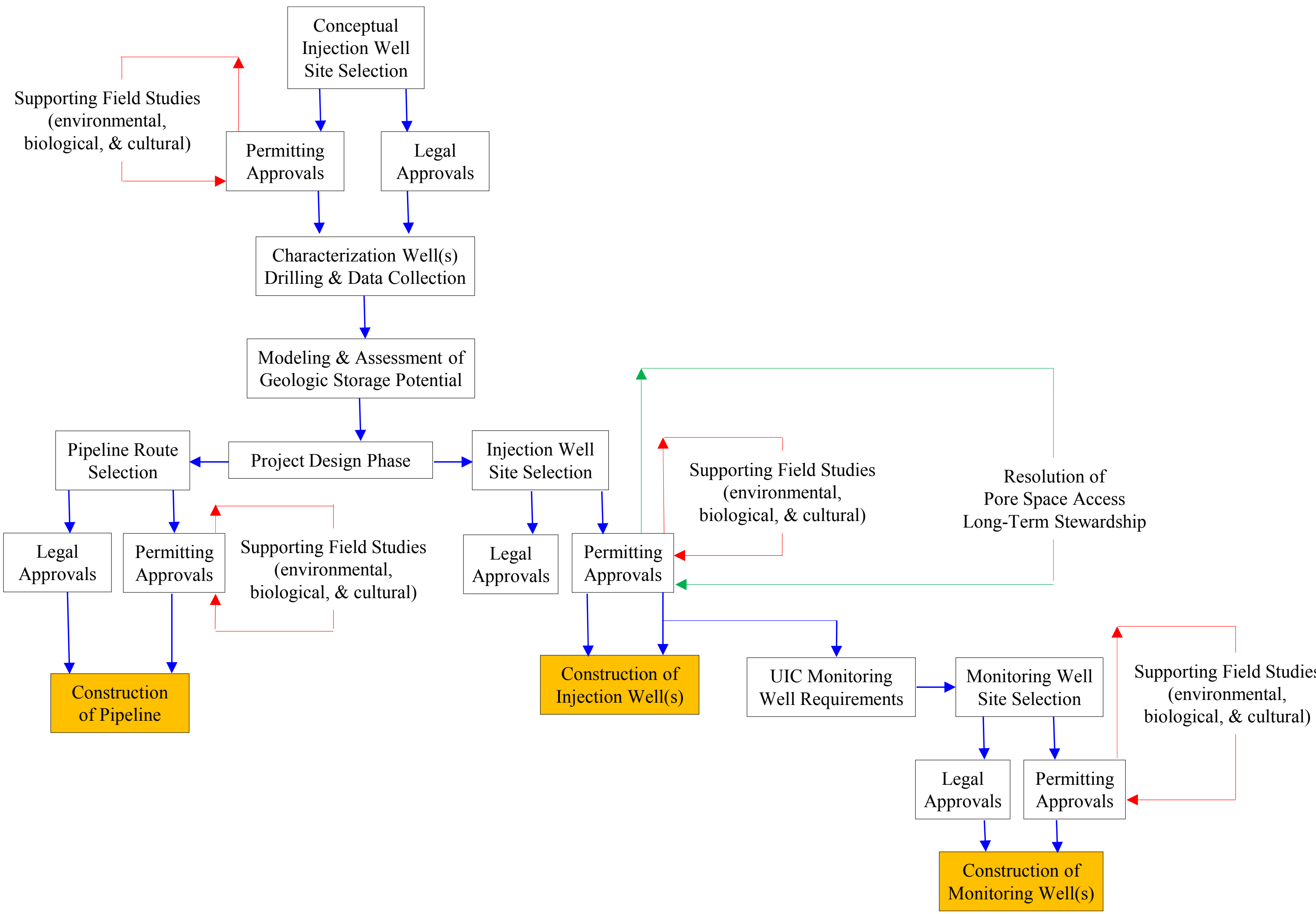
9. Extensive permitting requirements introduces significant schedule and financial challenges to the development of CCS technologies

Permitting related challenges to the viability of any CCS project, include:

- The size of the CCS project alone (capture, transport, and storage systems) requires extensive field studies to evaluate biological, cultural, and wetland resources to support the preparation of permit applications;
- The complexity of issues involved with developing a CCS project falls under the jurisdiction of many regulatory agencies. This adds significant complexity in regards to coordinating overlapping and, at times, conflicting requirements between agencies;
- Inexperience in permitting CCS related issues by the developer and the regulator adds time to the application and permit development process, as well as uncertainty in the stringency of the final requirements;

The challenges significantly impact project schedule and finances. The figure below provides context on these issues related just to pipeline and well development. Each step within this process not only adds scope and time to the project, but also comes with uncertainty in regards to various regulatory approvals and pitfalls that may result from field studies and construction activities. Simply, the permitting process for the pipeline and well aspects of a CCS project alone could take *years* to resolve before construction could even begin.

**Example of Permitting Complexity for CCS Projects**



**D. EPA's rationale for eliminating full capture CCS as the BSER is equally applicable to partial capture CCS**

EPA eliminated full capture CCS as the BSER for fossil fuel-fired boilers and IGCC units based only one reason – cost. As EPA notes:

> "*We previously indicated that the costs - $147/MWh for the new SCPC unit* [with full capture CCS] *and $136/MWh for the new IGCC unit* [with full capture CCS] – *are not reasonable and we rejected that option as BSER on that basis.*"[261]

and

> "*These* [full capture CCS] *costs exceed what project developers have been willing to pay for other low GHG-emitting base load generating technologies... For that reason alone, we do not believe that the costs of full implementation of CCS are reasonable at this time.*"[262]

AEP agrees that on the basis of cost alone, full capture CCS is not the BSER. In addition on the basis of any number of technical, financial, regulatory, or practical considerations, alone or collectively, full capture CCS is not the BSER. Nonetheless, EPA's rationale for eliminating full capture CCS would be <u>much stronger</u> if the agency considered the more realistic cost estimates for full and partial capture that have been experienced by actual projects (including the very project examples that EPA references in the proposed rule). EPA's determination would also be strengthened if the consideration was given to the cost estimates developed by other major assessments (including the type of major assessments that EPA discusses in the proposed rule as being necessary to evaluate complex issues that require judgment).

If "*for* [these] *reason*[s] *alone*,"[263] EPA rejects full capture as the BSER, then the higher cost range identified by the experience of projects to date and more comprehensive major assessments clearly indicates that <u>neither full capture CCS, nor partial capture CCS is the BSER</u> for fossil fuel-fired boiler and IGCC units.

[261] 79 Fed. Reg. 1478. (January 8, 2014).
[262] 79 Fed. Reg. 1477. (January 8, 2014).
[263] Id.

The following contrasts the types of CCS-related cost escalations that EPA relies upon in their analysis of the BSER:

**EPA Cost Analysis of CCS Technologies**[264]

| Unit | Configuration | LCOE $/MWh | CCS Related Cost Increase | EPA Conclusion |
|---|---|---|---|---|
| SCPC | No CCS | 92 | --- | --- |
| SCPC | Partial CCS, No EOR | 110 | 20% | Justifies partial capture as the BSER |
| SCPC | Full, 90% CCS | 147 | 60% | Too expensive. Full capture eliminated as BSER |
| IGCC | No CCS | 97 | --- | --- |
| IGCC | Partial CCS, No EOR | 109 | 12% | Justifies partial capture as the BSER |
| IGCC | Full, 90% CCS | 136 | 40% | Too expensive. Full capture eliminated as BSER |

When compared to the experiences of actual projects and the assessments from organizations that much more thoroughly follow and are directly involved in CCS development issues, EPA's cost assessment misses the mark by a very wide margin both in terms of the magnitude of costs involved and with respect to the current state of CCS development. Others have reached different conclusions regarding the cost of CCS. For example:

- On February 11, 2014, Deputy Assistant Secretary of Energy Dr. Julio Friedmann testified that first generation carbon capture technology on coal-based generating plants will increase the cost of electricity by 70 to 80%.[265]
- In 2013, the Global CCS Institute estimated first-of-a-kind CCS would increase the cost of electricity by 61 to 76% for post-combustion processes and 37% for IGCC units.[266]
- 2010 DOE/NETL CCS Roadmap estimated CCS will add 80% to the cost of a new pulverized coal plant and 35% to the cost of a new IGCC plant.[267]

EPA's range of a 12 to 60% cost increase for CCS is far below the aforementioned estimates of DOE and others that approach 80% or more. EPA eliminated full capture CCS as the BSER on the sole basis that it would be too expensive (40 to 60% cost increase).[268] The 40-60% cost increase that EPA estimates for full capture CCS

- "does not meet the cost criterion of BSER"[269];
- "is outside the range of costs...and should not be considered BSER"[270];

[264] 79 Fed. Reg. 1476 (January 8, 2014)
[265] Friedmann, J. Oral Testimony before U.S. House of Representatives Committee on Energy and Commerce. (Feb 11, 2014)
[266] "The Global Status of CCS: 2013". (Oct 2013). Global CCS Institute. p 172.
[267] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec 2010). p. 10
[268] 79 Fed. Reg. 1477. (January 8, 2014).
[269] 79 Fed. Reg. 1497. (January 8, 2014).

- "are not reasonable and...[are] rejected....as BSER on that basis.[271]"

If the 40-60% increase was sufficient to eliminate full capture, then the 80+% cost increase that has been experienced by active projects and that has been estimated by DOE and others is **more than sufficient** to eliminate partial and full capture as the BSER.

### E. EPA's rationale for eliminating CCS as the BSER for the natural gas combustion turbine source category is equally applicable to CCS for fossil fuel-fired boilers and IGCC units

EPA correctly eliminated partial and full capture CCS as the BSER for natural gas fired-combustion turbines ("NGCT") based on technical feasibility concerns. Much of EPA's rationale in eliminating CCS for NGCT's is equally applicable to coal-based generation units as well. In regards to technical feasibility, EPA correctly cites the lack of sufficient information and industry experience to eliminate CCS as the BSER by noting for example:

> "*CCS has not been implemented for NGCC units, and we believe there is insufficient information regarding the technical feasibility of implementing CCS at these types of units.*"[272]
>
> "*The EPA is not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard.*"[273]
>
> "*EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units.*"[274]
>
> "*Adding CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements. The cyclical operation, combined with the already low concentrations of $CO_2$ in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC.*"[275]
>
> "*It is unclear how part-load operation and frequent startup and shutdown evens would impact the efficiency and reliability of CCS. We are not aware that any of the pilot-scale CCS projects have operated in a cycling mode. Similarly, none of the larger CCS*

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[270] 79 Fed. Reg. 1435. (January 8, 2014).
[271] 79 Fed. Reg. 1478. (January 8, 2014).
[272] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[273] Id. (emphasis added)
[274] Id. (emphasis added)
[275] Id. (emphasis added)

*projects being constructed, or under development, are designed to operate in a cycling mode.*"[276]

To summarize, CCS was eliminated as the BSER for natural gas combustion turbines because:

- CCS "has not been implemented on NGCC units";
- No CCS demonstrations have occurred on NGCC units that "would justify setting a national standard"; and
- "insufficient information" is available to assess the "transfer" of CCS experience from other industries, the performance of CCS under "typical NGCC" operating conditions, and the technical feasibility of CCS for NGCT's.

In order to address these issues, the agency indicated that more information is needed from "*larger scale demonstration projects on units operating more like a typical NGCC*." Such information would be essential to evaluate technical concerns, as well as financial, regulatory, and other uncertainties.

AEP agrees with the technical concerns identified by EPA eliminate CCS as the BSER. AEP also agrees that large-scale demonstration projects (note plural as identified by EPA) are a key aspect of any strategy to address these concerns, and that such large-scale demonstration projects have not yet occurred on any NGCC process. However, as discussed throughout our comments, these same concerns **are equally, if not more applicable** to the application of CCS to coal-based generating units. AEP is greatly troubled that EPA has applied a double-standard for evaluating CCS for coal-based generation and natural gas-fired combustion turbine units.

As an example of the agency's double standard in evaluating CCS for each source category consider how the $CO_2$ capture experience of the natural gas and other industries is characterized and applied in the BSER analysis for each. In the BSER analysis for coal-based generation, EPA's discussion of this experience includes:

- "*Capture of $CO_2$ from industrial gas streams has occurred since the 1930's*"[277]
- "*These* [$CO_2$ capture] *processes have been used in the natural gas industry*"[278]
- "[T]*here are currently twenty-three industrial source CCS projects in twelve states that are either operational, under-construction, or actively being pursued which are or will supply captured $CO_2$ for the purposes of EOR.*"[279]
- "*Each of the core components of CCS – $CO_2$ capture, compression, transportation, and storage – has already been implemented*"[280]

[276] Id. 1485. (emphasis added)
[277] Id. 1471.
[278] Id.
[279] Id. 1474

- "*The U.S. experience with large-scale $CO_2$ injection..., combined with ongoing CCS research, development, and demonstration programs in the U.S. and throughout the world provide confidence that capture, transport, compression and storage...can be achieved.*"[281]

EPA **avoids discussion** of this broader industrial CCS experience in their BSER analysis for NGCT units – even though that experience is noted to have occurred within the natural gas industry and in processes similar to NGCT units. In fact, the extent of EPA's discussion of CCS experience in the BSER analysis for NGCT units is as follows:

> "*The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream.*"[282] This "*one demonstration project....is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.*"[283]

The agency provides no details or citations for this single CCS project on an NGCC unit,. The proposed rule does not even mention the name of the facility! While this one project alone <u>was not</u> a commercial-scale integrated $CO_2$ capture and geologic storage project, and as a result <u>is not</u> compelling enough to conclude that CCS is the BSER, the operating experience and lessons learned should have at least been evaluated by the agency. The CCS project that EPA references was a carbon capture process installed at the Northeast Energy Associates Bellingham Plant – a natural gas combined cycle plant located in Bellingham, Massachusetts. From 1991 to 2004, the plant operated a $CO_2$ capture system that captured 365 short tons/day of $CO_2$,[284] which was stored in tanks onsite and trucked as necessary to a nearby food processing industry (approximately 106,000 tonnes/year[285]). As the capacity factor of the plant declined, it became uneconomical to continue operation of the capture system.

EPA clearly made little, if any, attempt to understand and learn from this experience as suggested by the agency's characterization of the effort as being a "demonstration project." However, a system that operates for 14 years and is shutdown due to market conditions is far from a demonstration project, even if it <u>was not</u> a commercial-scale capture project and <u>did not</u> include integrated pipeline and storage systems. The Bellingham Plant used the Econamine FG capture process – a process that has been applied to over 23 commercial plants to recover $CO_2$

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280 Id. 1471.
281 Id.
282 Id. 1436.
283 Id. 1485
284 Fluor's Econamine FG Plus[SM] Technology For $CO_2$ Capture at Coal-fired Power Plants. Satish Reddy, et al. Presented at Power Plant Air Pollutant Control "Mega" Symposium. (Aug 2008). Baltimore, Md. pp 3-4.
285 Final Report of the Interagency Task Force on CCS. (Aug 2010). p. A-2

from flue gas associated with natural gas combustion – none of which represent commercial-scale NGCC $CO_2$ capture projects integrated with pipeline and geologic storage systems.[286]

A review of the "extensive literature record" on CCS was included in the BSER evaluation of technical feasibility for coal-based units, which consisted of only three documents that EPA in turn used to support their position on CCS for coal-based units. The BSER for NGCT units **does not** include any literature review. Coincidently, two of the three documents relied upon in the BSER evaluation for coal-based units discuss the experience of CCS systems on natural gas combustion turbines. The Report of the Interagency Task Force on CCS that EPA references includes a list of natural gas power plants and combustion sources that are equipped with carbon capture systems.[287] The Pacific Northwest National Laboratory report that EPA relies upon has a section devoted to the experience of carbon capture systems on natural gas power plants, which includes two facilities that use Econamine capture systems similar to the Bellingham Plant that EPA ambiguously references in the proposed rule.[288] The report also notes that "*$CO_2$ has been captured...from natural gas power plants since the early 1990s.*"[289] While none of these reports reference commercial-scale NGCC $CO_2$ capture projects integrated with pipeline or geologic storage systems, it is noteworthy that these examples were ignored entirely even though the experience is much broader than for coal-based electric generation units.

In fact, an evaluation of these CCS experiences on natural gas combustion turbines and the prospects of applying this experience to future NGCC process is non-existent in EPA's BSER for NGCT units. Ironically, even though the Econamine capture system that has been used by NGCC processes **has yet to be demonstrated on a single coal-based generating unit**, EPA assumes in its cost analysis for the BSER that new pulverized coal units with CCS will be equipped with the Econamine system.

So if 14 years of experience using the Econamine capture process at one NGCC unit, along with years of related experience at other natural gas-fired facilities is not worthy of consideration, yet alone mention, within the BSER analysis for NGCT units, then how can the fictional use of that same Econamine capture process, which has never been demonstrated on a

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286 Fluor's Econamine FG Plus[SM] Technology: An Enhanced Amine-Based $CO_2$ Capture Process. Satish Reddy, et al. Presented at the Second National Conference on Carbon Sequestration. NETL/DOE. May 2003. p. 2.

287 Final Report of the Interagency Task Force on CCS. Aug 2010. p. A-2

288 "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. Pacific Northwest National Laboratory. Dooley, et.al. PNNL-18520. (Jun 2009). See Section 4.4 "Post-Combustion $CO_2$ capture from Natural Gas-fired Facilities". p. 10.

289 Id. p.8

single coal-based unit, carry a shred of weight in evaluating the technical feasibility or potential costs of CCS for coal-based units? Obviously, the answer is that it cannot and the fact that EPA's reliance on the use of this capture system is further evidence that EPA's BSER analysis for coal-based generation units is flawed and its determination of partial CCS as the BSER has no credibility.

### F. EPA's BSER determination is flawed because it does not consider all source types within the source category

For the natural gas combustion turbine source category, EPA relied upon a variety of technical, operational, and other factors to conclude that CCS is not the BSER. These include the low concentration of $CO_2$ in natural gas combustion streams, frequency of load change, and a lack of commercially demonstrated CCS. These same factors are applicable to and even more pronounced with the operation of natural gas-fired boiler generating units. However, EPA gave zero consideration to these issues for natural gas boilers. Instead, the focus of EPA's evaluation of CCS as the BSER for fossil fuel boilers is solely on coal-based generating units. Therefore, in regards to natural gas-fired boiler generating units (as well as for coal-based units as discussed elsewhere in our comments), EPA has proposed an NSPS that, by EPA's own logic for combustion turbines, is not technically feasible and has not been adequately demonstrated.

## X. Highly Efficient Generating Technologies are the BSER for Fossil-Fuel Fired Boilers and IGCC Units

### A. EPA has not objectively evaluated highly efficient generation technologies and has prematurely eliminated this option as the BSER

EPA's analysis of highly efficient generating technologies is woefully inadequate and has the strong appearance of being, at best, nothing more than a hastily prepared and clumsily executed box-checking exercise that:

- does not "provid[e] the EPA greater assurance that it is basing its judgment on the best available, well-vetted science"[290];
- does not "address the scientific issues that the Administrator must examine"[291];
- does not "represent the current state of knowledge on the key elements"[292]; and

[290] Id. 1456.
[291] Id. 1440.
[292] Id. 1440.

- does not attempt to "comprehensively cover [or] obtain the majority conclusions from the body of scientific literature. [293]"

For example, EPA's evaluation of highly efficient technologies made

- no attempt to define highly efficient technologies;
- no attempt to understand or articulate the key variables that impact efficiency;
- no attempt to assess the prospects of developing solutions to reduce the impacts from these key variables on unit efficiency;
- no attempt to identify or assess the operation of highly efficient generation technologies domestically or internationally as the agency attempted with CCS;
- no attempt to quantify the potential emission reductions associated with the use of highly efficient generation technologies; and
- no attempt to assess the overall environmental benefits of highly efficient generation technologies compared to CCS technologies.

It is noteworthy that EPA's entire evaluation of highly efficient new generation is **<u>less than one page</u>** of the 90 page Federal Register version of the propose rule.[294] Yet, based on this evaluation, EPA decides to "*not consider them* [e.g. highly efficient generation without CCS] *to qualify as the BSER for the following reasons: (a) Lack of Significant $CO_2$ Reductions*...[and] *(b) Lack of Incentive for Technological Innovation.*"[295] Both reasons are invalid.

Consider again EPA's analogy that compares the BSER determination process to that of determining the "best baseball player," both of which involve a "complex weighing of several criteria" based on an "exercise of judgment."[296] EPA's evaluation of highly efficient generating technologies is equivalent to determining who is the "best baseball player" by simply looking at players in a team picture, while ignoring individual statistics, performance on the field, players on other teams, or up and coming player prospects.

Unfortunately, EPA has also ignored the significant progress that continues to be made around the world in developing and operating more efficient coal-based generation technologies. The same DOE/NETL report that EPA relies upon throughout the evaluation of CCS as the BSER discusses these efficiency improvements **<u>on the very first page</u>**:

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[293] Id. 1440.
[294] 79 Fed Reg. pp. 1468-1469. Section B.1 "Highly Efficient New Generation Without CCS Technology" (January 8, 2014).
[295] 79 Fed Reg. 1468. (January 8, 2014)
[296] 79 Fed. Reg. 1466. (January 8, 2014)

"*The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with great improvements in efficiency...*"[297]

With the value that EPA placed on extensively using this report in the evaluation of CCS as the BSER, it is unclear how this promising insight on the recent experience and future prospects of efficiency improvements could have been overlooked or failed to at least piqued EPA's interest in thoroughly investigating efficiency opportunities, especially because EPA notes that its "crucial to take initial steps now to limit GHG emissions from fossil fuel-fired power plants."[298] EPA's lack of interest in seriously evaluating highly efficient generating technologies is even more surprising because the agency has evaluated such technologies in depth at least three times in recent years in the following reports:

- March 2011: "PSD and Title V Permitting Guidance for Greenhouse Gases" U.S. EPA;
- October 2010: "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units" U.S. EPA; and
- July 2006: "Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies" U.S. EPA.

Collectively, these EPA reports

- determined site-specific drivers that impact unit efficiency
- assessed design opportunities for efficiency improvements
- reviewed ultra-supercritical boiler technologies
- identified and discussed specific domestic and international projects that are utilizing and advancing the development of higher efficient coal generation technologies

In addition, the 2010 report states that EPA was developing a publicly-accessible database of GHG mitigation technologies. It was noted that the "database is a tool that provides information on both commercially available technologies, as well as emerging technologies that are being demonstrated at larger scales for commercial viability."[299] At least as of 2011, EPA was progressing on the development of the database and was actively presenting updates and discussion beta versions at various conferences.[300]

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297 Cost and Performance Baseline for Fossil Energy Plants. Vol.1. Rev.2a. NETL. Sept 2013. p.v. (emphasis added)
298 79 Fed Reg. 1433. (January 8, 2014)
299 "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA. (Oct 2010). p. 40
300 www.epa.gov/air/caaac/pdfs/1_11_GMOD_CAAAC.pdf (Accessed Feb 21, 2014)

Alarmingly, none of this extensive information was utilized or even referenced in EPA's less than one page evaluation of highly efficient generation technologies. It is unclear why EPA completely ignores this information, as consideration of these reports and other related information would clearly indicate that highly efficient generation technologies are the BSER.

### B. Highly efficient generating technologies are technically feasible

Even though EPA determines that highly efficient generation processes are technically feasible, the agency makes no attempt to identify such technologies or to understand the levels of performance that currently are or have the potential to be achievable. Instead, EPA cavalierly determines that "*supercritical or ultra-supercritical coal-fired boilers or IGCC units...are clearly technically feasible*" with zero context.[301]

At present, ultra-supercritical technology represents the most efficient design option available for coal-fired boilers. However, the proposed rule does not provide a serious, objective evaluation of the technology, and in fact mentions "ultra-supercritical" *only* five times, two of which are found in a footnote the states:

> "*Ultra-supercritical (USC) and advanced ultra-supercritical (A-USC) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.*"[302]

That is the extent EPA's discussion on ultra-supercritical technologies. EPA does not attempt, even qualitatively, to evaluate the availability, experience, or prospects of ultra-supercritical technology. EPA implies that advanced-ultrasupercritical might be a better option than USC, but offers no distinction or additional information. In fact, the aforementioned footnote is the **only time** that the term "advanced ultra-supercritical" appears in the entire rule. It is as if EPA by the use of the phrase "terms often used" dismisses higher efficiency processes as being common-place, inconsequential technologies that are fully mature and have no prospects for growth, which is far from reality. Ultra-supercritical technologies are only beginning to emerge as a cost-effective design preference for new coal-based generation projects. For example, the first ultra-supercritical pulverized coal unit in the U.S. began operating in 2012, the world's first supercritical circulating fluidized bed coal unit began operating in 2009 in Poland, and the first USC CFB units are currently being developed.

[301] 79 Fed. Reg. 1435. (January 8, 2014).
[302] 79 Fed. Reg. 1468. (January 8, 2014).

Currently, research and development of advanced-USC (i.e. generation technologies that approach 50% or greater efficiency) is showing strong promise and near-term prospects are widely recognized. A summary of perspectives on advanced-ultrasupercritical technologies follows that should prompt EPA to perform a complete assessment of these technologies in its evaluation of highly efficient generation technologies:

| Source: | Perspective on Advanced-USC Technologies |
|---|---|
| World Coal Association | "Research and development is under way for ultra-supercritical units operating at even higher efficiencies, potentially up to around 50%"[303] |
| Babcock & Wilcox<br>Power Generation Group | "The technical viability of A-USC is being demonstrated in the development programs of new alloys" and "Design concepts for advanced ultra-supercritical steam generators are being developed."[304] |
| International Energy Association<br>"Technology Roadmap for High-Efficiency, Low-Emissions Coal-Fired Power Generation" | "Development of A-USC aims to achieve efficiencies in excess of 50%"... "Efforts to develop advanced USC technology could lower emissions (a 30% improvement). Deployment of advanced USC is expected to begin within the next 10 to 15 years"[305] |
| US DOE, Ohio Coal Development, EPRI<br>"Boiler Materials for Ultrasupercritical Coal Power Plants" | "a project aimed at identifying, evaluating, and qualifying the materials needed for the construction of the critical components of coal-fired boilers capable of operating at much higher efficiencies.. This increased efficiency is expected to be achieved principally through the use of advanced ultrasupercritical (A-USC) steam conditions." [306, 307] |

It is clear that significant development strides have been made and are actively being pursued to advance the efficiency of coal-based generation technologies. Competition from other generation technologies and regulatory drivers will continue to drive these efforts. The fact that EPA has completely dismissed the potential of these technologies is a clear indication that the agency had no intention to objectively consider higher efficiency generation technologies, regardless of the benefits or opportunities such technologies could provide as part of an overall GHG reduction strategy. Not only has EPA ignored the potential for higher efficiency generating units, but also EPA has made no attempt to understand the successful experience of projects using these technologies all around the world.

For example, the AEP Turk Plant is the first ultra-supercritical pulverized coal generating unit in the U.S. Since beginning commercial operations in 2012, the Turk Plant has

303 www.worldcoal.org/coal-the-environment/coal-use-the-environment/improving-efficiencies/
304 www.babcock.com/library/Documents/BR-1852.pdf
305 www.iea.org/publications/freepublications/publication/TechnologyRoadmapHighEfficiencyLowEmissionsCoalFiredPowerGeneration_Updated.pdf
306 www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022037
307 www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Jeffrey%20Phillips%20-%20EPRI%20-%203-24-11.pdf

demonstrated superior performance with respect to increased unit efficiency, reduced auxiliary power demand, lower emissions profiles, and a lower overall environmental footprint. Operations at the Turk Plant represent significant advancements that are a foundation for even greater advancements *if given the opportunity*. A conventional supercritical unit operates at steam temperatures of 1,000 – 1,050°F, while an ultra supercritical (USC) unit operates at steam temperatures grater than 1,100°F. Steam conditions for the Turk Plant are 1,110°F (main steam) and 1,125°F (reheat steam). By operating at these higher steam temperatures, the turbine cycle is more efficient, which in turn reduces fuel (coal) consumption and thereby reduces emissions, combustion byproducts, and water demand. Historically, the utility industry has been reluctant to move to USC technologies due to operational risks, availability, and reliability concerns. However, developments in advanced materials technologies have addressed many of these concerns and now allows for better performing and more affordable piping and turbine components that can withstand higher temperatures.

Despite the performance to date and the prospects for advanced ultra-supercritical designs, EPA gives <u>only one passing reference</u> to the Turk Plant in the proposed rule. Given the accomplishments represented by Turk and the potential that it has to set the standard for new generation, it would only be reasonable to think that EPA would thoroughly and proactively evaluate and consider the opportunities and potential of such technology in their BSER analysis. However EPA made no attempt to even begin to understand AEP's experience at the Turk Plant in terms of the design, performance, and opportunities it represents for ultra-supercritical technology. AEP would welcome such a dialogue and invites EPA to tour the Turk Plant to expand their knowledge of USC technology and to strengthen their BSER evaluation.

In the consideration of CCS as the BSER, EPA referenced <u>**nine**</u> international projects and databases listing <u>**dozens**</u> of other international efforts related to various aspects of CCS development. But in the evaluation of highly efficient generating technologies as the BSER, EPA referenced <u>**zero**</u> projects although significant efforts are occurring worldwide that have been widely recognized. The table below summarizes some of these efforts, which should prompt EPA to perform a complete assessment of these technologies in their evaluation of highly efficient generation technologies. Ironically, information on four of the projects comes from a 2010 EPA Report that evaluates available and emerging technologies for reducing GHG emissions from coal-fired generating units – a report that EPA ignores in the proposed rule.

| International Project: | Comments: |
|---|---|
| Lagisza Power Plant (Poland) [308] | World's first supercritical CFB unit<br>Commenced operations in 2009 |
| Lunen Power Plant (Germany) [309] | "Most Efficient...Coal-fired Power Plant in Europe)<br>Commenced operations in December, 2013 |
| Manjung Plant (Malaysia) [310] | 1,000 MW ultra-supercritical plant<br>Commence Construction in 2014 /Operations in 2017 |
| Isogo Plant[311] (Japan) | 600 MW ultra-supercritical plant<br>Commenced Operation in 2009 |
| Niederaussem Power Station (Germany) [312] | 965 MW ultra-supercritical plant<br>Commenced operation in 2002 |
| Nordjylland Power Plant (Denmark) [313] | 384 MW ultra-supercritical plant<br>Commenced operation in 1998 |

In regards to IGCC processes, EPA has incorrectly portrayed the maturity and performance of the technology. While IGCC is technically feasible, it has not been adequately demonstrated. This is evidenced by the experiences of the only two commercial-scale IGCC projects under construction and commissioning in the U.S.: Kemper and Edwardsport. Both represent a FOAK integration and scale-up of process components. Both have experienced significant cost escalations throughout their design and construction and neither has been demonstrated to be equivalent or more efficient than other coal-based generation technologies. These factors are indicative of a technology that is early in its development cycle. In addition, the number of cancelled IGCC projects due to technical and financial issues is more evidence that the technology is far from being fully developed. For example, a NETL database indicates at least 16 potential IGCC projects have been cancelled in the U.S. in recent years.[314]

Further, no pilot-, validation-, or commercial-scale CCS process has been demonstrated with an IGCC process. The IGCC process alone faces significant development risks and barriers to being adequately demonstrated and commercialized. Aside from the Kemper project, which has yet-to-be-constructed and does not have a $CO_2$ limit or CCS operating requirements within its air permit, the integration of CCS into the IGCC process will add significant complexity and

[308] www.powermag.com/operation-of-worlds-first-supercritical-cfb-steam-generator-begins-in-poland/
[309] www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2013/energy/power-generation/ep201312013.htm
[310] www.sumitomocorp.co.jp/english/news/detail/id=27067
[311] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA. (Oct 2010). p. 31
[312] Id.
[313] Id
[314] www.netl.doe.gov/research/coal/energy-systems/gasification/gasification-plant-databases

risks that would make future IGCC projects prohibitive. EPA ignores these risks and barriers completely in the BSER analysis and incorrectly relies upon fictional IGCC performance and cost information that is premised on vendor estimates of future, fully mature processes that have never been constructed and that have certainly not been demonstrated. Therefore, any analysis, including the evaluation of the BSER, is flawed that relies upon such information to assess cost-effectiveness and emission reductions, or to establish the standard that would apply to all coal-based generation technologies.

**C. Highly efficient generating technologies are cost effective**

Despite the many flaws in its evaluation of technical feasibility and the lack of quantitative or even a credible qualitative analysis, EPA concludes that high efficiency generating technologies should not be eliminated as the BSER on the basis of cost. AEP agrees that certain highly efficient generating technologies are cost effective as evidenced by the number of projects that are being successfully completed worldwide. The difference between the initial and final costs of these projects is not significant in many cases, which is also representative of technology that has matured beyond FOAK projects. In fact, many of these projects have been financed without a dependence on government subsidies, another sign of the lower risk and confidence of such technology advancements.

In regards to IGCC, any cost estimates for future projects are speculative at best due to the early stage of development. The two IGCC projects under active construction and commissioning in the U.S. are both FOAK processes and have both experienced significant cost escalations throughout their development. It is premature to utilize the experience of these projects to estimate the cost of future IGCC projects. In addition, there is zero value in EPA's cost-analysis that ignores these active projects and relies upon vendor estimates of never constructed IGCC units.

### D. Highly efficient generating technologies provide meaningful emission reductions, and have less overall environmental impacts compared to CCS systems

1. EPA incorrectly downplays and dismisses the emission reductions that may be achieved by highly efficient generating technologies

EPA quickly eliminates highly efficient generation technologies because "*they do not provide meaningful reductions in $CO_2$ emissions from new sources.*"[315] EPA is incorrect. Without any attempt to credibly evaluate current or future performance capabilities, the agency simply discredits any benefits that may be realized by noting that:

> "*Efficiency-improvement technologies alone result in only very small reductions (several percent) in $CO_2$ emissions, especially in contrast to those achieved by the application of CCS.*"[316]

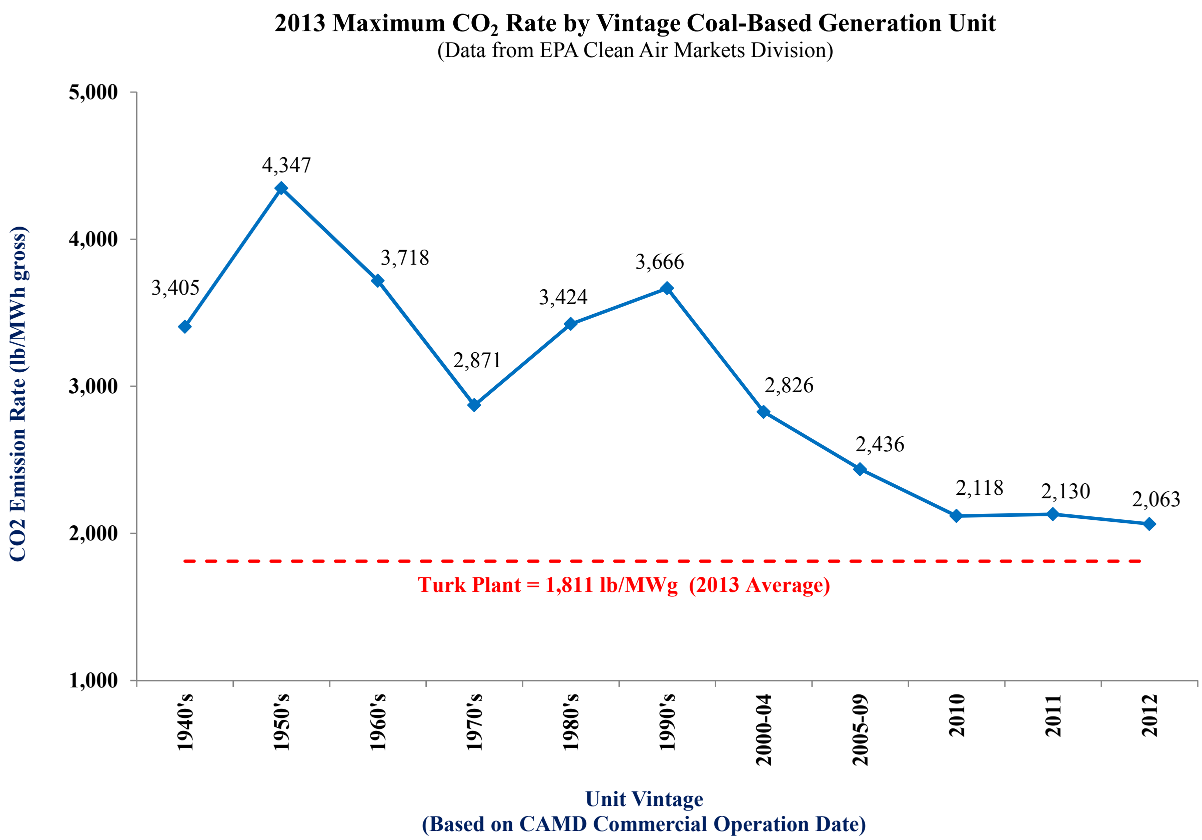
EPA provides no explanation of the criteria for determining "meaningful reductions" or "very small reductions," other than that such reductions are not the same as the potential reductions from CCS technologies. Because EPA provides no analysis that even begins to quantify the magnitude of potential emission reductions from more efficient technologies, the agency is in no position to assume "only very small reductions" are possible. The agency also provides no analysis of the magnitude of emission reductions that may be realized with the development of more advanced technologies whose optimistic prospects are widely recognized. The following sections provide such an evaluation using data from EPA's own databases, to demonstrate that the development of highly efficient generation technologies has historically, is presently, and will continue in the future to set new standards for providing for significant emission reductions from coal-based generating units.

2. The development of highly efficient generation technologies continues to provide meaningful emission reductions

Throughout the history of coal-based electric generation, the development and implementation of higher efficiency generation technologies has occurred that has enhanced operations, increased reliability, reduced emissions, and minimized other environmental impacts. A review of emissions data contained in the EPA's Clean Air Market Division ("CAMD") database highlights these historical trends.

[315] 79 Fed. Reg. 1435. (January 8, 2014)
[316] Id.

The CAMD database was accessed to obtain the following for all coal-based generating units in the U.S: 2013 annual $CO_2$ emissions, 2013 gross generation data, and the commercial operating date of each unit.[317] A total of 820 coal-based generating units were identified with sufficient information to compute $CO_2$ emission rates (pounds per gross megawatt hours) for comparison.[318] The 820 units were then grouped by the decade that they commenced operation beginning with 1940's vintage units. A more refined grouping was made of units that have commenced operation since 2000. The maximum $CO_2$ emission rate was then calculated for each vintage of units and compared to the 2013 performant of the AEP Turk Plant. Results are summarized below.




[317] CAMD data per http://ampd.epa.gov/ampd (May 1, 2014).
[318] Id. Derivation of 820 units: 3,602 in database. 943 units with coal as the "primary fuel." 121 units eliminated due to insufficient data. 2 units eliminated primarily fired natural gas in 2013. Thus, 943 units – 121 - 2 = 820 units.

The figure depicts the significant technological advancements that have been and continue to be achieved that improve process efficiencies and lower the $CO_2$ emission rate of next generation coal-based generating technologies. The maximum emission rates trend lower over the time period, which is indicative that greater efficiencies are being realized across a number of different coal types and combustion technologies. The historical improvements in $CO_2$ emission rates would be expected to continue with the emergence of higher efficiency technologies that are currently being developed.

3. A BSER determination based on high efficient generation technologies alone would produce significant emission reductions

EPA is incorrect to assume that efficiency improvements offer little potential for significant emission reductions. An analysis of 2013 emissions data from the EPA's CAMD database indicates an NSPS based on the best performing existing unit would yield significant $CO_2$ reductions in new units. For example, consider the 42 coal-based generating units that have commenced operation after 2000. If these units were to be constructed today to achieve a GHG NSPS limit derived from the best performing existing units, significant $CO_2$ reductions would occur. The 2013 CAMD database contained 820 coal units with sufficient emission data to include in the analysis.[319] Expanding the hypothetical scenario above towards replacing entire existing U.S. coal fleet would reduce greater than 100 million tons of $CO_2$ annually. The table below summarizes $CO_2$ reductions assuming each of these units meets various hypothetical NSPS standards:

[319] Id.

| | Total Units | 2013 CAMD CO2 (tons) | 2013 CAMD Generation (MWh gross) | 2013 Average CO2 Rate (lb/MWg) | Hypothtical CO2 Tons at a rate of 1,850 lb/MWg | Hypothtical CO2 Tons at a rate of 1,800 lb/MWg | Hypothtical CO2 Tons at a rate of 1,775 lb/MWg |
|---|---|---|---|---|---|---|---|
| Coal Units that began operation after 2000 | 42 | 125,981,368 | 129,611,577 | 1,944 | 119,890,709 | 116,650,420 | 115,030,275 |
| | **Hypothetical CO2 Reductions from 2013 CAMD** | | | | 6,090,659 | 9,330,949 | 10,951,093 |

| | Total Units | 2013 CAMD CO2 (tons) | 2013 CAMD Generation (MWh gross) | 2013 Average CO2 Rate (lb/MWg) | Hypothtical CO2 Tons at a rate of 1,850 lb/MWg | Hypothtical CO2 Tons at a rate of 1,800 lb/MWg | Hypothtical CO2 Tons at a rate of 1,775 lb/MWg |
|---|---|---|---|---|---|---|---|
| All 2013 CAMD coal-units | 820 | 1,678,393,342 | 1,657,369,741 | 2,025 | 1,533,067,010 | 1,491,632,767 | 1,470,915,645 |
| | **Hypothetical CO2 Reductions from 2013 CAMD** | | | | 145,326,332 | 186,760,575 | 207,477,697 |

To provide context on the types of benefits that higher efficiency technologies could provide consider the Turk Plant is the first and only coal-based generation unit in the U.S. that employs ultra supercritical technology. The 2013 CAMD database identified 819 additional existing coal-based generation units (e.g., not including the Turk Plant). Assume that all of these units are retired and that their capacity is replaced with a coal-based generating unit that is *at least* equivalent to the Turk Plant in terms of efficiency and emission rates. Such a scenario would yield the following for the <u>same capacity</u> generated in 2013 by these existing units:[320]

- Reduced $CO_2$ emissions: 177,000,000 tons (11% reduction)
- Reduced $SO_2$ emissions: 2,755,000 tons (88% reduction)
- Reduced $NO_x$ emissions: 1,232,000 tons (81% reduction)

In addition, replacing these existing 819 units, many of which have a smaller design capacity compared to the 600 MW Turk design, would only require approximately 400 new units. Generating the same capacity with less than half the number of units would greatly simplify the magnitude of development, construction, permitting, and permitting related considerations. Such a scenario would preserve the benefits and value of maintaining the role of coal as part of a balanced energy portfolio for the U.S. Rather than prohibit future coal-based

[320] Id.

generation units, the aforementioned scenario would enable even more advanced generation and emission control systems, including CCS, to be developed, demonstrated, and commercialized.

4. Highly efficient generation technologies provide greater overall environmental benefits compared to CCS technologies

The overall environmental benefits of higher efficiency generation technologies are superior to those afforded by CCS technologies. For example, higher efficiency technologies utilize less coal, water, and raw materials (i.e. ammonia for $NO_x$ removal, limestone for $SO_2$ removal, etc.) to generate the same amount of electricity compared to lower efficiency processes, including those might be equipped with CCS systems. This significantly increases auxiliary load and reduces the overall output of the process. In other words, for a given generating unit designed to meet a specific demand capacity, that unit would have to be significantly oversized to accommodate the increased auxiliary power requirements of CCS technology. The end result of this oversized design is the need to utilize more coal, water, and raw materials with the result being more emissions, wastewater, and combustion byproducts.

**E. Determining highly efficient generating technologies are the BSER would promote technology development**

EPA eliminates highly efficient technologies as the BSER, in part, because such a standard would "*not advance the development and implementation of control technologies to reduce $CO_2$ emissions*" and "*does not develop control technology that is transferrable to existing EGUs*."[321] EPA is incorrect and fails to offer even a basic quantitative or qualitative analysis to support their position.

An NSPS based on the adequately demonstrated performance of the most efficient operating units would absolutely drive future innovation, such as the development of units that use alternative combustion technologies or coal types that could also meet the standard. It would also accelerate the advancement of technologies that provide a greater compliance margin below the NSPS, increased operating flexibility, and reduced development risks. Further, it is expected that the development of efficiency improvement technologies could be transferred to existing EGUs. Such efficiency-based improvements certainly would be more readily transferred to existing units than CCS technologies, which are handicapped with significant integration, financial, regulatory, and siting challenges that simply could not be accommodated by the

[321] 79 Fed. Reg. 1469. (January 8, 2014).

existing fleet. In any event, it is not clear that the consideration of technology transfer to existing sources is a necessary metric that EPA should weigh in determining the BSER.

In addition, EPA eliminates highly efficient technologies because they do not "*promote the development of generation technologies that would minimize the auxiliary load and cost of future CCS requirement*" and because "*such a standard could impede the advancement of CCS technology*."[322] Is EPA proposing an NSPS based on the use of the BSER, or is EPA proposing a CCS development rule? For the reasons presented in other sections, CCS is clearly not the BSER. Actually, the further development of highly efficient technologies could actually benefit the development of CCS. Nonetheless, the development of more efficient technologies that require less auxiliary load and that generate less $CO_2$ per output would be beneficial for any new coal-based unit, regardless of whether CCS is included in the design.

As noted in the comments on technical feasibility, significant progress is being achieved on the development of higher efficiency generating technologies. In addition, it is widely recognized that significant opportunities remain for the development of even more advanced generation technologies and that such development will continue to set new standards for unit efficiency for all types of coal-based generation technologies.

### F. EPA should establish an NSPS subcategory that is specific to IGCC as these processes are fundamentally different from other coal generation technologies

#### 1. IGCC technology is not a one-size-fits-all process design

The term IGCC represents a broad range of process designs that incorporate varying gasification technologies, syngas cleanup methods, power generation strategies, and other plant systems. The scope of process differences reflects the impact of coal quality variables on design features, as well as the immaturity of the technology. The design and performance of IGCC units that are operating or under construction are not representative of all IGCC technologies.

NETL has been actively involved in IGCC development for decades and maintains an extensive library of information on gasification and related technologies. The following from NETL highlights some of the different IGCC design options that are being developed.

[322] 79 Fed. Reg. 1469. (January 8, 2014).

## Gasification Technologies[323]

Gasification involves the oxidation of coal into a syngas that can be used for power generation or processed into synthetic fuels or chemical feedstocks. Design options include the method of coal injection into the gasifier (dry-feed or slurry-feed) and the type of oxidant used (oxygen or air). Gasifiers can be broadly classified into three categories (entrained-flow, fluidized-bed, and fixed-bed). Various gasifier technologies are summarized below, each has its own unique set of design and operating variables:

| Gasifier Category | Gasifier Design | Coal Feed to Gasifier | Oxidant | IGCC Units in the U.S. |
|---|---|---|---|---|
| Entrained-Flow | GE Energy | Slurry-Feed | Oxygen-Blown | Polk<br>Edwardsport |
| Entrained-Flow | CB&I E-Gas | Slurry-Feed | Oxygen-Blown | Wabash |
| Entrained-Flow | Shell | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | Siemens | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | PRENFLO | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | MHI | Dry-Feed | Air-Blown | none |
| Entrained-Flow | EAGLE | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | HCERI | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | ECUST | Slurry-Feed<br>Dry-Feed | Oxygen-Blown | none |
| Fluidized-Bed | KBR Transport | Dry-Feed | Air-Blown<br>Oxygen-Blown | Kemper |
| Fluidized-Bed | High Temp Winkler | Dry-Feed | Air-Blown<br>Oxygen-Blown | none |
| Fluidized-Bed | U-GAS | Dry-Feed | Air-Blown<br>Oxygen-Blown | none |
| Fluidized-Bed | Great Point Energy | Dry-Feed | Catalytic Gasification | none |
| Fixed-Bed | Lurgi | Dry-Feed | Oxygen-Blown | none |
| Fixed-Bed | British Gas Lurgi | Dry-Feed | Oxygen-Blown | none |

[323] www.netl.doe.gov/File%20Library/Research/Coal/energy%20systems/gasification/gasifipedia/index.html (Accessed Apr 14, 2014)

Syngas Cleanup Systems

A range of syngas cleanup systems have been identified by NETL, most of which have not been demonstrated on a commercial-scale IGCC unit. These systems can be categorized as particulate removal systems, acid-gas removal systems, and other syngas cleanup processes.

**IGCC Particulate Removal Systems**[324]

| Category | Process |
|---|---|
| dry particulate removal | cyclone technology |
| dry particulate removal | candle filters |
| wet particulate removal | water scrubbing |

**IGCC Acid Gas Removal Systems**[325]

| AGR System | Solvent |
|---|---|
| Chemical Solvents | Primary Amines |
| Chemical Solvents | Secondary Amines |
| Chemical Solvents | Tertiary Amines |
| Chemical Solvents | Potassium Carbonate |
| Physical Solvents | Selexol |
| Physical Solvents | Rectisol |
| Physical Solvents | Purisol |
| Mixed Solvents | Sulfinol-D |
| Mixed Solvents | Sulfinol-M |
| Mixed Solvents | Flexsorb SE/SB |
| Mixed Solvents | Amisol |

**Other IGCC Syngas Cleanup Systems**[326]

| Category | System |
|---|---|
| Sulfur Recover & Tail Gas Treatment | Claus Process |
| Sulfur Recover & Tail Gas Treatment | SCOT Tail Gas Treatment |
| Sulfur Recover & Tail Gas Treatment | Sulfuric Acid Synthesis |
| Sulfur Recover & Tail Gas Treatment | Potassium Carbonate |
| Syngas Cleanup System | COS Hydrolysis |
| Syngas Cleanup System | Water Gas Shift |
| Syngas Cleanup System for Mercury | Activated Carbon |

[324] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/particulate-removal (Accessed Apr 14, 2014)
[325] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/agr (Accessed Apr 14, 2014)
[326] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/sulfur-recovery (Accessed Apr 14, 2014)

Power Generation Strategies

Design options are available for IGCC that can impact the emissions profile for the unit. The first is fuel selection as units may be designed and operated to accommodate a range of feedstocks to the gasifier that could be blended with coal. With respect to the combustion turbines, design considerations include the type (manufacture and vintage) of turbine deployed, co-firing options with natural gas, the use of low $NO_x$ burner technologies and/or water injection. In regards to the heat recovery steam generator (HRSG), consideration includes duct-firing capabilities and the use of SCR or oxidation catalyst technologies, which to date have yet to be demonstrated on a coal-based IGCC unit. The future use of hydrogen-based combustion turbines will also impact the emissions profile. In addition, the design of IGCC processes is often integrated with poly-generation options, which expands the purpose of these facilities beyond power generation and which further supports the need for an IGCC specific subcategory.

Summary

In summary, a suite of IGCC design options are being developed for a variety of coal types and operating scenarios. To date, IGCC technology has been demonstrated at only two units in the U.S., with two other units coming online in the near future. The design of these four facilities represents only a fraction of the coal-based IGCC process configurations that could be used in the future. These facilities represent FOAK technologies and their performance and capabilities present significant risks and uncertainties. The use of CCS technologies would introduce another level of integration risk and operational uncertainty. As a result, the efficiency and $CO_2$ rates for these IGCC processes is to be determined and warrants establishing a separate NSPS subcategory that is specific to IGCC units.

2. An NSPS subcategory specific to IGCC should be established to address the unique design and operation of these processes

IGCC processes are inherently different from other methods of coal-based electric generation and more similar to natural gas combined cycle units. Coal-derived $CO_2$ emissions can be emitted from a number of processes within the IGCC unit depending on the operating scenario. In addition, coal-based $CO_2$ emissions can be commingled with the $CO_2$ emissions from other fuels consumed by various IGCC systems. Because of these unique operating and design characteristics, a separate NSPS subcategory specific to IGCC should be established. Issues that this subcategory would have to consider include:

- operating scenarios when coal-based syngas is not consumed by the combustion turbines, but by other process systems, such as a flare, thermal oxidizer, etc.
- operating scenarios when the combustion turbines are firing only natural gas or co-firing natural gas and coal-based syngas
- operating scenarios when the combustion turbines are consuming coal-based syngas and natural gas is combusted in duct burners in the heat recovery steam generator
- operating scenarios when coal and other carbonaceous compounds (petcoke, biomass, municipal solid waste, etc.) are simultaneously being gasified to produce a syngas
- combustion turbines that use synthetic natural gas (coal-based syngas) that is produced offsite by another facility

### G. EPA has incorrectly assessed the performance capabilities of new coal-based generating technologies that are designed with CCS

EPA uses a single NETL report[327] from 2010 to assess the performance capabilities of new coal-based generation technologies.[328] This report was discredited at length in comments above regarding the flawed CCS cost analysis performed by the agency. Likewise, the report is unreliable for assessing the performance of highly efficient generation technologies due to (i) a narrow reliance on dated vendor supplied conceptual designs for coal-based generation technologies that have **never** been constructed, operated, or proven; and (ii) an evaluation that is restricted to generation technologies that only use bituminous coals, with **no consideration** given to the use of lower rank coals.

In fact, no data has been found that validates the related emission rates from this report that EPA purports has been or are capable of being demonstrated. EPA blindly accepts the information without any consideration of the actual performance of operating units. Such operating data is readily available through the EPA Clean Air Markets Division (CAMD) database. At a minimum, EPA should thoroughly analyze operating data from the CAMD database to inform their assessment of what emission rates are being demonstrated in practice. The agency should then expand this analysis by engaging operators, vendors, and equipment manufactures to evaluate performance drivers and to determine emission rates that are representative and sustainable for various coal-based generation technologies.

[327] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010)
[328] 79 Fed. Reg. 1468 (January 8, 2014)

### H. The BSER determination for fossil fuel-fired boilers and IGCC units must be based on highly efficient generating technologies

EPA made no attempt to seriously evaluate the current status and future prospects of highly efficient generation technologies. Across the world, significant progress is occurring to successfully develop more highly efficient technologies that are establishing new standards for the performance of coal-based generating technologies. EPA's decision to eliminate highly efficient technologies on the basis of insufficient emission reductions and the lack of future technology development is incorrect and should be replaced with an honest, objective review of such technologies. Clearly, high efficient technologies have the potential to yield significant emission reductions. The prospects for significant advancements in high efficiency technologies is widely recognized and would be more aggressively pursued if such technologies were determined to be the BSER.

In evaluating highly efficient generation technologies, EPA should:

- review prior EPA evaluations of highly efficient generation technologies;[329]
- perform a detailed evaluation of operating data that are readily available in databases maintained by the agency;
- evaluate the demonstrate performance of international efforts and current research and development program so that the current and long-term capabilities of highly efficient generating technologies be more accurately quantified;

From these evaluations, informed conclusions can then be made regarding any differences in the performance capabilities of specific generation technologies and/or for specific fuel characteristics that would drive decisions regarding the appropriate subcategories and corresponding emission rates that represent the best system(s) of emission reduction. The result will be technically proven and legally acceptable standards based on the use of highly efficient generating technologies for at least the following subcategories: (i) non-IGCC coal-based generating units; (ii) fossil-fuel fired IGCC generating units; and (iii) natural gas-fired boiler generating units.

[329] For example, EPA evaluated efficiency in the following reports: (a) "PSD and Title V Permitting Guidance for Greenhouse Gases" March 2011; (b) "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units" October 2010; and (c) "Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies" July 2006

## XI. Flaws in the Regulatory Impact Analysis and Supporting Economic Analyses

EPA's methodology for assessing the costs and benefits of this proposed rule is incomplete and factually disconnected from scientific and economic realities. EPA has not effectively accounted for the potential impacts of this rule under a full range of possible future market conditions and thus has hidden the true potential costs of this regulation. Instead of robust scenario analysis, EPA has overly relied upon "one-off" calculations and comparisons. Policymakers and the general public need to be fully informed of the potential costs of this proposed rule through a comprehensive and well-informed analysis.

### A. Cost Analysis

EPA erroneously concluded that the proposed rule will have negligible costs or impacts on society based on the flawed premise that no new coal plants will be built absent this rule. This is inconsistent with EIA scenarios showing new unplanned coal additions prior to 2020[330] and significant additions of new coal generation under certain model scenarios in later years. EPA arbitrarily examined the costs of the rule only through 2022, based on the eight-year review cycle for Section 111(b) regulations. This is a significant and glaring omission in the analysis in that truncation of the regulatory period in question hides the true potential cost of the regulation. Furthermore, even with an eight-year regulatory review cycle, this regulation is likely to set a *de facto* emission rate limit for future review periods.

New baseload generating capacity takes a number of years to plan, permit, engineer and construct. Some generating assets coming online after 2022 will have to be planned and permitted prior to 2022, and thus will be subject to the proposed standard. EPA's argument that reviewing the NSPS within eight years renders post-2022 analysis irrelevant is incorrect. Truncating the analysis based on a presumed future regulation is also at odds with previous EPA assertions that it will not speculate on future rulemakings in its modeling efforts. EPA states in the documentation for the IPM results that the base case represents "a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized."[331]

[330] www.eia.gov/oiaf/aeo/tablebrowser/
[331] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter1.pdf

Equally troubling is EPA's reliance upon a single forecast of projected new generation using coal and natural gas prices that run out to only 2022. It is impossible to say that new coal-fired generation is not going to be cost-effective in the future based on a single modeled outcome or without considering potential coal and gas prices in the post-2022 time period. Other scenarios recently developed by EIA indicate that, under varying market conditions projected in the past, some new generation may be built prior to 2022 (~300 MW) and many other new coal units may in fact be built post-2022.[332] EPA made little effort to quantify the impacts of these alternative scenarios due to the arbitrarily truncated period for which it chose to analyze impacts. Furthermore, EPA failed to examine any additional combination of scenarios beyond those previously published. As an example, under a scenario where natural gas resources are less economically developed and the Climate Uncertainty Adder (to be discussed later) is removed dramatically more coal builds would occur.

Trends in planned and projected generation tend to oscillate substantially, largely due to the volatility in fuel commodity markets. As an example, less than six years ago, in the 2008 Annual Energy Outlook, EIA forecast 89,000 MW of new unplanned coal additions by 2030. Just eight years ago, in the 2006 Annual Energy Outlook, EIA forecast 145,000 MW of unplanned coal additions. Immediately prior to those forecasts, however, there was an unprecedented build-out of new natural gas combined cycle capacity, with the belief that those facilities could displace existing coal generation. Thirty years prior to the natural gas build-out, there was a similar boom with nuclear power, accompanied by the prediction that nuclear energy would be "too cheap to meter." These previous forecasts and historical build cycles illustrate that future generation options and projections are extremely sensitive to future commodity pricing, regulatory requirements, and external events. A myopic view of these influences leads to wasteful and disruptive boom and bust cycles in generation development.

The electric utility industry is currently in a unique period in which material (*e.g.*, steel and concrete) and fuel costs for coal-fired generation have seen dramatic increases at the same time that natural gas prices have reached record lows not seen in the past decade, and the demand for electricity has been suppressed due to the prolonged recession and benign weather. However, many analysts expect natural gas prices to rise significantly in the future, as the near term glut of natural gas eventually dissipates. Recent spikes in natural gas pricing due to cold weather and

[332]www.eia.gov/oiaf/aeo/tablebrowser/

high levels of consumption have illustrated that this effect can and will occur. This situation could be exacerbated in the near future as the Mercury and Air Toxics Standards rule will force retirement of otherwise economical coal-fired capacity that can only be replaced with NGCC technology, which will sharply increase natural gas demand in a compressed time period.

Natural gas pricing has historically been extremely volatile and is the largest determinant of what type of new electric capacity will be built, due to its strong correlation with power pricing. EPA's RIA states on page 4-31 that:

> "*The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). Over the last decade, gas prices (both Henry Hub prices and delivered prices to the power sector) have ranged from below $3 to nearly $10/mmBtu on an annual average basis*."

AEP agrees and notes that domestic and international natural gas prices have historically experienced seasonal and annual volatility that resulted in significant spikes for periods of time. The extreme volatility in natural gas pricing should lead to the logical conclusion that structuring the cost benefit/analysis for this rule on a single gas forecast extending through only 2022, with prices near the lowest levels of the past decade, is not a rational or prudent approach. Instead, multiple natural gas price trajectories should be examined in conjunction with the cost analysis for the rule.

While EIA has examined the role that higher electricity sales and lower yields from shale gas could have on new capacity decisions, there are other factors that could have even more dramatic impacts on natural gas pricing and new build economics. For example, a move to gas liquefaction and export within either the U.S. or Canada has the potential to drive up domestic natural gas prices to levels seen internationally, which can be three to four times higher than current domestic prices.[333] EPA's IPM model does not take into account the development of these facilities, even though announced facilities and current market conditions suggest they will be developed. Additionally, a drop in world oil prices could slow down oil and natural gas liquids production activities, reducing the supply of associated gas and increasing the price of natural gas.

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[333] www.forbes.com/sites/energysource/2012/06/13/theu-s-has-a-natural-gas-glut-why-exporting-it-as-lng-is-a-good-idea

Furthermore, EPA's economic modeling used in this rulemaking has not appropriately assessed the impacts of the final MATS rule and other pending regulations, which will lead to the retirement of many coal-fired generating units, further increasing the demand and hence the price for natural gas. The associated reduction in coal use will also influence coal pricing (and reduce coal prices), making new coal fired generation more viable economically. Notably, when spreads between gas and coal prices reach approximately $4 per MMBtu, coal plants become economic to build relative to combined cycle gas plants. Historically there have been many periods where these spreads have existed between gas and coal prices, such as the period from 2003 to 2008. Thus, shale gas recovery levels are only one of many factors that can influence natural gas pricing. A broader range of scenarios needs to be explored within the cost-assessment. For each scenario, the cost of this regulation should be assessed, using at least a 30-year time horizon.

**B. Levelized Cost Analysis**

Numerous comparisons are made using the Levelized Cost of Electricity (LCOE) within the RIA and the proposed rule, in an attempt to illustrate that (a) new coal is not the currently preferred choice for new generation and (b) coal with carbon capture is of a similar cost to new nuclear as second baseload power option. While the LCOE of electricity is often used within the electric industry as a comparative tool, the results of LCOE analysis can be easily biased by incorrect or misleading assumptions, as is the case as presented with the proposed rule. In addition, as discussed above in comments on the cost analysis performed in the BSER, the reports that EPA relies upon for LCOE information are insufficient for performing reliable analyses.

Underlying the LCOE analysis is EPA's broad assumption that new NGCC units can meet its proposed standard of performance, which is 1,000 lb $CO_2$/MWh of electricity generated on a gross basis. However, one study has indicated that many smaller plants will not be able to meet this standard.[334] Additionally, even efficient units could have trouble meeting the standards if gas prices should increase, changing the duty cycle of the units, and creating additional

[334] See Matthew J. Kotchen and Erin T. Mansur, How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?, at 9 (Apr. 25, 2012), available at www.dartmouth.edu/~mansur/papers/kotchen_mansur_co2standards.pdf (finding that "71 percent of the [combined cycle gas turbine] units scheduled to come on line through 2017 would have CO2 emission rates that meet the target").

inefficiencies associated with cycling or ramping of output. EPA should include in its LCOE analysis the additional costs of having to build larger and more efficient units to cope with temporary, intermittent, or unexpected operating conditions. EPA should also conduct a detailed analysis of the effect of unit cycling on meeting the standard. If units must be forced to run even if their cost of operation exceeds the power price to meet the efficiency standard, the increased operational cost should be considered in the cost analysis.

The cost and performance data used by EPA on NGCC is overly optimistic. EPA cites capital cost for advanced combined cycle of $821/kW in 2012$ and an efficiency of 50.2% based on a NETL report. However, AEP's experience suggests total installed capital costs of 40+% higher. Furthermore, NGCC operating experience indicates that average achievable efficiency over the course of a year are several percentage points less than EPA is assuming due to the startup, shutdown, and cycling of equipment. Additionally, the EPA/NETL VOM cost of $1.8/MWh (2011$) is substantially less than the $3.27/MWh (2012$) EIA is currently using.[335]

There is also an unfair bias against new supercritical coal within the LCOE calculations based on the assumed operation and maintenance costs. The values used by EPA from NETL for FOM and VOM of $70.6/kW-yr and $7.70/MWh (2011$) respectively are significantly higher than the $31.18/kW-yr and $4.47/MWh (2012$)[336] being used by EIA. This further skews the comparison of natural gas versus conventional coal.

The LCOE also assumes an 85% capacity factor for all technologies being analyzed. This is factually disconnected with how new generation types will operate. Within the U.S., generators typically dispatch on variable cost, with lower cost sources dispatching more frequently. Over the long run, coal generation will dispatch more frequently than gas generation due to fuel costs approximately 50% less (on a MWh basis) than natural gas, as presented in LCOE analysis. Thus, EPA and EIA's assumption that new coal units and new natural gas units will have the same operation and capacity factors is incorrect. NGCC will not run at 85% of their capacity over the course of a year. Even with the historically low natural gas prices of 2012 and 2013, AEP's combined cycles ran substantially less. EPA should revise the levelized cost calculations to include more reasonable assumptions for natural gas plant operation. Results from broader electric sector modeling could be used to provide the appropriate basis for this

[335] http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8_2_2014er.pdf
[336] Id.

number. The misrepresentation of the capacity factor results in vast underestimation of the fixed capital charges needed to be recovered from a NGCC unit per MWh of operation and incorrectly skews the cost downward.

Based on the aforementioned errors, the differences in levelized cost between NGCC and SCPC units is dramatically overstated and is particularly compounded by the use of a Climate Uncertainty Adder (CUA) within several of the comparisons, as discussed later in the comments. Therefore, EPA's statement that "it is only when natural gas prices reach $10.94/MMBtu on a levelized basis (in 2011 dollars) that new coal-fired generation without CCS becomes competitive in terms of its cost of electricity"[337] is patently false. Underestimation of NGCC capital and operational costs, overstatement of NGCC operational hours, and overstated operational costs for new coal units make the breakeven number significantly lower. This is demonstrated by the EIA analysis, which identifies new coal as being built in various sensitivity cases; even though EPA states that "none of the EPA sensitivities or AEO2013 scenarios approach this natural gas price level on either a forward looking 20-year levelized price basis or on an average annual price basis at any point during the analysis period."[338] These new coal builds occur within the model due to more accurate input data being used and the model correctly calculating the effect cost of new generation based on actual operation.

The RIA also assumes the levelized cost of coal with CCS are similar to nuclear power to determine that they represent similar options for non-natural gas low-carbon baseload power. As discussed above in comments on the cost evaluation performed for the BSER analysis, significant concerns exist regarding accuracy and representativeness of the CCS related cost estimates. For example, with the relatively high operating cost of a coal unit with carbon capture these types of units should not be modeled as baseload units with an 85% capacity factor. Adjusting for this factor alone, coal with CCS is likely to be much more expensive than new nuclear. Therefore, any position that the proposed emission limitation is justified from a cost comparison basis with nuclear is erroneous.

[337] RIA at 5-48
[338] Id.

### C. IPM Modeling

EPA made several critical errors in the development of the IPM model and the runs used in support of the cost analysis. One major flaw in the IPM model is the double counting of $CO_2$ risk exposure. As stated in the RIA on page 5-15, "*both EIA and EPA include a capital charge rate adder (3 percent) for new conventional coal-fired generating capacity without CCS, which reflects the additional cost of raising capital that is currently reflected in the marketplace, related at least in part to uncertainty surrounding future greenhouse gas emission reduction requirements.*" Because this proposed NSPS removes much of the uncertainty regarding GHG emission reduction requirements by setting a standard, this penalty should be reduced or removed altogether in the modeling of the reference case for comparison purposes. The use of this penalty in the reference case is an inappropriate bias against new coal generation.

The IPM model also uses outdated capital cost inputs associated with new generation sources. EPA estimates that new NGCC will cost \$976/kW in 2007 dollars.[339] This is substantially lower than estimates by the Electric Power Research Institute (EPRI) of \$1275–1375/kW in 2010 dollars.[340] Even correcting for inflation, EPA's capital cost is ~20 to 25% lower than EPRI's estimate. Conversely, EPA projects that a new pulverized coal plant will cost \$2,918 – \$3,008/kW, in comparison to EPRI's cost of \$2,400 – \$2,760/kW. In this case, EPA's cost of new coal generation is ~15 to 30% higher than EPRI's estimates. In both cases, these flawed cost estimates artificially bias the model to new gas generation in lieu of coal generation by overstating the cost of coal capacity and understating the cost of gas capacity. This discrepancy should be corrected within IPM going forward.

### D. Benefit Analysis

It is arbitrary for EPA to propose a rule with no substantive quantifiable benefits. As stated on page 1-4 of the RIA, "*EPA anticipates that the proposed EGU New Source GHG Standards will result in negligible $CO_2$ emission changes, energy impacts, quantified benefits, costs, and economic impacts.*"

EPA ineffectively tries to qualitatively describe potential tangential benefits that "*may*" occur, such as reducing regulatory uncertainty. However, this proposal will create even *greater*

[339] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter4.pdf
[340] EPRI, Program on Technology Innovation: Integrated Generation Technology Options - Technical Update (June 2011).

uncertainty because of its novel treatment of existing modified and reconstructed sources. As an example, EPA is relying on its purported authority to promulgate a "new source" standard that does not apply to "modified" units (notwithstanding the controlling definition of "new source" in Section 111(a)(2) of the CAA) during a period when other EPA regulatory initiatives will require existing coal plants to undertake physical and operational changes in order to achieve reductions in criteria pollutant emissions that are known to increase the hourly rate of $CO_2$ emissions from coal-fired steam generators. EPA claims that such sources will be protected by the "pollution control project" exclusion in 40 CFR § 60.14(e)(5). EPA acknowledges that this exclusion (dating to 1975 in the NSPS program) is similar to a provision subsequently promulgated under the new source review regulations in Part 51, and that the D.C. Circuit Court's decision in *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005), invalidated that similar provision in the new source review program. The questionable continuing validity of the pollution control exclusion may well force additional coal unit retirements, beyond the 38,000 MW already announced, even though EPA has acknowledged that it has insufficient information to develop standards that could apply to existing sources.

Even if a source were willing to undertake such a risk and accept that installation of additional criteria pollutant controls would eventually require the capture and storage or sequestration of $CO_2$, uncertainty persists regarding the availability of adequate sequestration sites within reach of existing units, the actual performance of available capture technologies, the actual performance of long term sequestration operations, and the long-term regulatory framework for liability. EPA touts the use of DOE funding for CCS projects. However, the DOE has repeatedly pulled funding from its FutureGen project. DOE funding alone has been insufficient to allow half of the award recipients to continue with planned projects and depends upon an appropriation system that is subject to the federal budgeting process.

EPA also presents calculations using a benefit per ton reduced for $NO_x$ and $SO_2$ that suffer from additional flaws. National Ambient Air Quality Standards are designed to protect the human and ecological health with an adequate margin of safety. Additional reductions of these pollutants well below these standard levels should not have **any** quantifiable health benefit. Additionally, the modeling and calculations presented by EPA ignore the projected impacts of the MATS Rule on air quality, which in many cases will drive emissions below the Lowest Measured Levels in the studies used to support the health claims, thus invalidating the applicability of the studies to a benefit calculation. Furthermore, the Krewski et al. and Lepeule et al. studies which underpin the health benefit calculations that EPA estimates[341] use data from the 1980s and 1990s that do not take into account current air quality emission levels or trends. For example, air emissions post-MATS implementation are going to be significantly lower than the years used in these studies. Additionally, these studies fail to differentiate health response between various components of particulate matter even though more recent studies show associations between locally produced carbonaceous compounds but *NO* associations between utility produced $SO_2$ and $NO_x$ emissions.[342] There is also concern with EPA's continued use of the Value of a Statistical Life calculated from willingness to pay survey results as these results do not appropriately value premature mortality that could be measured in days. A more robust measure needs to be developed that appropriately values premature mortality with consideration to temporality.

Given the acknowledged limitations of the analyses presented, EPA should not include any discussion of health benefits within the RIA as any such benefits are indirect and speculative. Furthermore, EPA should update its calculations of health benefits to include use of a broader range of scientific literature, including peer-reviewed studies showing no association with PM and mortality and significant issues with health benefit calculation methodologies.[343]

### E. Social Cost of Carbon

EPA uses the Social Cost of Carbon (SCC) to characterize potential carbon benefits associated with the rule, with even though it is widely acknowledged that these cost estimates are inaccurate, uncertain, and highly speculative.[344] EPA acknowledges in the RIA that "*any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.*" As such, these

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[341] (see, e.g., RIA at 5-42)

[342] Examples include: (1) Grahame TJ. 2009. Does improved exposure information for PM2.5 constituents explain differing results among epidemiological studies? Inhal .Toxicol. 21: 381-393; (2) Lipfert FW, Wyzga RE, Baty JD, Miller JP. 2009. Air pollution and survival within the Washington University-EPRI veterans cohort: risks based on modeled estimates of ambient levels of hazardous and criteria air pollutants. J Air Waste Manag Assoc. 2009 Apr;59(4):473-89; and (3) Grahame T, and Hidy GM. 2007. Pinnacles and Pitfalls for Source Apportionment of Potential Health Effects From Airborne Particle Exposure. Inhal .Toxicol. 19: 727-744.

[343] Graven et al. An Approach to the Estimation of Chronic Air Pollution Effects Using Spatio-Temporal Information. Journal of the American Statistical Association. 2011

[344] (see RIA 5-36 through 5-39)

calculations cannot form the basis of an adequate RIA. AEP has submitted comments on the SCC in its development and use and they are attached as Appendix F to this document.

**F. Climate Uncertainty Adder**

Both EPA and EIA make use of a climate uncertainty adder (CUA) within integrated economic modeling and in presenting the LCOE for new electric generating options. The premise behind the CUA is to represent the fact that risks associated with future climate policy are likely to impact choices for new generation. While in practice the carbon policy risk does factor into planning decisions, the CUA is being improperly used. For example, many utilities use a carbon price in their planning decisions, however this price is typically back loaded within the planning period given policy uncertainty and the regulatory development period necessary for such a variable to have practical effect. Therefore, the 3% WACC adder as currently employed is artificially high.

Furthermore, within generation planning processes, carbon policy assumptions are typically applied across all fossil fuel choices and are coupled with a market response to energy pricing, if modeled within an integrated electric sector and/or economy-wide model. Therefore, inclusion of the CUA only with respect new coal does not provided the appropriate perspective or feedback on true carbon risk as it would suggest there is no carbon risk associated with other fossil fuels, namely natural gas.

Carbon risk should be accounted for outside of a LCOE comparison, and thus the CUA should not be included as part of LCOE. When modeling the electric sector as a whole, it may be appropriate to characterize carbon risk, but to provide a true "apples to apples" LCOE comparison, the CUA should never be included. A number of external factors play into generation investment decisions, which are also not "monetized" within the LCOE. Removing the CUA adder from the LCOE would dramatically reduce the breakeven natural gas price necessary to favor new coal. Any future analysis by either EPA or EIA should not use a CUA in evaluation of technology.

## XII. Comments on the Structure of the Proposed NSPS

### A. Adequacy of Proposed Fossil Fuel-fired Boiler and IGCC NSPS

As discussed previously, CCS clearly does not qualify as the BSER within the meaning of section 111(a) of the Clean Air Act. EPA requested comment on whether the proposed standard of 1,100 lb/MHh should more appropriately be set within the range of 1,000 to 1,200 lb/MWh.[345] These rates have not been proven to be technically feasible and have certainly not been adequately demonstrated for coal-based electric generation technologies. AEP recently completed construction of an ultra-supercritical unit, which is employing state-of-the-art advanced coal technology. Based on the subbituminous fuel used, the projections for load fluctuation and periodic unit startups, operations to date, and available information regarding equipment degradation over a units operational life, AEP estimates that an annual gross $CO_2$ emission rate of 1,900 lb/MWh would incent the development of more highly efficient generation technologies, while properly balancing the other factors (including costs) associated with the determination of the BSER.

### B. Adequacy of Proposed Natural Gas Combustion Turbine NSPS

EPA requested comment on whether the proposed standard of 1,000 lb/MWh should more appropriately be set within the range of 950 and 1,100 lb/MWh for the large turbine subcategory.[346] There are a number of factors that result in variability of emissions that have not been adequately considered by EPA: operating at part load, use of backup fuel, startup and shutdowns, performance degradation, and other factors. Also, increased cycling of NGCC to support integration of variable renewable resources is expected, as well as higher capacity factors of new NGCC units. In light of all these factors and considering the lack of commercially available $CO_2$ control technologies for fossil-fired generation, it is recommended that a more appropriate standard for new, large NGCC units is 1,100 lb/MWh or more.

[345] 79 Fed. Reg. at 1470.
[346] Id. at 1437.

### C. Applicability Requirements – Low Capacity Factor Stationary Turbines Should Be Clearly Exempted[347]

The original proposal explicitly did not apply to simple cycle turbines and AEP supports that exemption for simple cycle turbines instead of the current proposal. EPA's current proposal is that simple cycle turbines not be exempted if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year. EPA requests comments on a range of 20 to 40 percent of potential electric output sales on a three-year basis for the capacity factor exemption. EPA also requests comment on whether applicability for stationary combustion turbines should be defined on a single calendar year basis, similar to the current subpart Da applicability for criteria pollutants, instead of a three-year basis. Notwithstanding our comment that simple cycle turbines should be clearly exempted as originally proposed, if EPA retains the applicability criteria approach, AEP supports a 40 percent of potential electric output sale for a capacity factor exemption measured as a three-year rolling average for the capacity factor exemption. Additionally, in the case where simple cycle turbines are constructed with the intent to operate prior to the future construction of a heat recovery steam generator (HRSG), such turbines should be exempted from the proposed rule under these same criteria until such time that construction of the HRSG and related equipment is completed and the unit commences operation in a combined cycle mode.

### D. Before Establishing a Net-Output-Based Standard, EPA Must Conduct a Much More Detailed Technical Analysis

EPA requested comment on the use of net-output based standards either as a compliance alternative for, or in lieu of, gross-output based standards, including whether there should be a different approach for different subcategories.[348] In the NSPS for Subpart Da criteria emissions, EPA did not require a net output approach "[d]ue to the lack of net-output-based emission rates for multiple types of EGUs with various control configurations over a range of operating conditions."[349] EPA should be consistent in the use of gross-based output standards in this rulemaking. Generally, AEP supports the use of gross output-based standards, however, the use of gross-based generation results in a number of complex technical and operational considerations that can influence emission rates and unit efficiencies. These issues warrant a

[347] Id. at 1459.
[348] Id. at 1447.
[349] 73 Fed. Reg. 33,642 at 4.

much greater technical analysis, which further supports that finalization of these standards is premature and that the proposed rule should be changed to an advanced notice of proposed rulemaking so that the agency can fully evaluate the implications and design of gross-based output standards.

### E. In Regard to Startup, Shutdown, and Malfunction Requirements; An Affirmative Defense Is Necessary at a Minimum, But Standards Should Not Apply During Startup and Shutdown Periods[350]

Units that operate at lower capacity factors than those associated with baseload operations will have more startups and shutdowns and thus increased $CO_2$ emissions. Not accounting for the lower capacity units and more frequent startups and shutdowns punishes NGCC for that operational flexibility. Instead of including these periods, EPA should provide for work practice standards to minimize emissions during startup and shutdowns. If that change isn't adopted, then the proposed NSPS standard should be raised as discussed in paragraph B above. AEP supports the affirmative defense as the minimum necessary to protect EGU rights. The affirmative defense to civil and penalties for violation of emission limits that are caused by malfunctions, should apply to both the 12-operating-month standard and the 84-operating-month rolling average compliance option.

## XIII. Response to Miscellaneous EPA Requests for Comment

### A. AEP Supports an Exemption for the Coal Refuse Subcategory

EPA solicits comments on establishing a subcategory for coal refuse-fired EGUs.[351] AEP supports a subcategory that would exempt such units from the proposed NSPS requirements due to the environmental benefits of remediating coal refuse piles. Further, AEP supports additional fuel-specific subcategorization that establishes a coal-specific standard *that reflects the best demonstrated performance of existing advanced coal technologies.*

### B. Emergency Conditions – AEP Agrees that Net Sales During Emergencies Should Not Be Counted When Determining Applicability

EPA requests comment on excluding electricity generated as a result of a grid emergency declared by the RTO, ISO or control area Administrator as counting as net sales when

[350] 79 Fed. Reg. 1448 – 1450.
[351] Id. at 1496.

determining applicability as an EGU.[352] AEP supports the position that emergency conditions do occur and may require that all available operable EGUs interconnected to the electrical grid supply power to the grid.

### C. AEP Supports the Exclusion of Non-$CO_2$ GHG Emissions from the Rule

EPA requests comments on the appropriateness, technique, and frequency of measurement of and reporting of $CH_4$ and $N_2O$ emission from fossil fuel-fired EGUs as part of the proposed emissions standard. AEP supports EPA's proposal to not include these other GHGs because their emissions from EGUs are negligible when compared to $CO_2$. Because existing EGUs have been calculating and reporting $N_2O$ and $CH_4$ emissions under the GHG Reporting Rule since 2011, using emissions factors, additional measurement and reporting is not justified.

### D. AEP Supports EPA's Proposal to Not "Double Count" Rolling Violations When Additional Violations Occur Directly Following a 12-operating Month or 84-operating Month Averaging Period[353]

EPA proposes that the calculation of the number of daily violations within an averaging period be determined such that if a violation occurs directly following the previous 12-operating-month or 84-operating-month averaging period (during which the emission rate exceeds the standard), daily violations would not double count operating days that were determined as violations under the previous averaging period. AEP objects to the automatic imposition of penalties for exceedances without some exercise of discretion. There may be valid reasons, such as sustained periods of extremely cold weather that would support the need for exercise of enforcement discretion in cases of small exceedances of the $CO_2$ standards. These objections aside, AEP agrees that violations should not be "double counted."

[352] Id. at 1497.
[353] Id. at 1498.

## Appendix A

## Analysis of CCS Projects Referenced by EPA in the Proposed Rule

## Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

**EPA Referenced CCS "development" or "demonstration" Projects**

| EPA Reference | Unit Type[354] | CCS[355] | Project Status[356] | Comments |
|---|---|---|---|---|
| Kemper<br>(Southern Co) | IGCC<br>582 MW<br>(net)[357] | 3,000,000 tonnes/yr<br>EOR<br>Amine-based capture | Under Construction<br>Startup late 2014[358] | ▪ Final Air Permit = No $CO_2$ Limits[359]<br>▪ PSC Certificate = No $CO_2$ Limits[360]<br>▪ EIS Mitigation Action Plan[361]<br>➢ "The purpose of DOE's action....is to demonstrate the feasibility of this selected IGCC technology at a size that would be attractive to utilities for commercial operation." (p. 3)<br>➢ Demonstration period = 54 months (p. 4)<br>➢ "Use best efforts to achieve 67% carbon capture during the demonstration period" (p. 7) |
| SaskPower<br>BoundaryD am[362]<br>(Canada) | PC (rebuild)<br>160 MWg<br>110 MWn[363] | 1,000,000 tonnes/yr<br>EOR | Construction<br>Startup 2014 | ▪ FOAK – Integrated CCS |

[354] Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
[355] Unless noted CCS data from: Ackiewicz
[356] Unless noted Project Status from: Ackiewicz.
[357] Kemper County IGCC Project. Mitigation Action Plan. (DOE/EIS-0409). U.S. Department of Energy. September 2010. p. 4
[358] Kemper County IGCC Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/kemper.html (accessed February 24, 2014)
[359] Air Permit #1380-00017 (October 24, 2012). Mississippi Department of Environmental Quality.
[360] Mississippi Public Service Commission Order. RE: CPCN Petition from Mississippi Power Company. Docket 2009-UA-14. May 26, 2010.
[361] Kemper County IGCC Project. Mitigation Action Plan. (DOE/EIS-0409). U.S. Department of Energy. September 2010. p.
[362] Unless noted, all data for Boundary Dam project from: www.saskpowerccsconsortium.com/ccs-projects/saskpower-initiatives/carbon-capture-project/
[363] Boundary Dam CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/boundary_dam.html (accessed February 24, 2014)

## Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

**EPA Referenced CCS "development" or "demonstration" Projects**

| EPA Reference | Unit Type[364] | CCS[365] | Project Status[366] | Comments |
|---|---|---|---|---|
| Texas Clean Energy Project (Summit) | IGCC (polygen)<br>400 MWg<br>130-212 MWn[367]<br>(low net due to polygen design) | 2,200,000 tonnes/yr<br>EOR<br>Rectisol Capture[368] | Securing Financing<br>No Construction<br>Startup 2017 | ▪ Power Purchase Agreement with CPS Energy expired Dec 31, 2013[369]<br>▪ Latest update on project website was September 16, 2012.[370]<br>▪ Final Air Permit = No $CO_2$ Limits[371]<br>▪ No evidence that Class VI UIC permit has been obtained[372]<br>▪ EIS Record of Decision[373]<br>  ▪ "DOE's purpose...is to demonstration the commercial-readiness of $CO_2$ capture and geologic sequestration fully integrated with a power plant"<br>  ▪ Demonstration period = startup until July 15, 2017 (p. 60479)<br>  ▪ "use best efforts to achieve at least a 90 percent capture rate during the demonstration period" (p. 60480) |
| Hydrogen Energy California | IGCC (polygen)<br>405-431 MWg<br>151-266 MWn[374]<br>(low net due to polygen design) | 2,570,000 tonnes/yr<br>EOR | FEED Ongoing<br>No Construction<br>Startup ~ 2019 | ▪ EIS has not been finalized<br>▪ California Energy Commission Certificate has not issued<br>▪ When considering ASU and EOR related power, net output = 52.5 MW<br>▪ At maximum fertilizer production, plant is a net consumer from grid = 61.8MW[375]<br>▪ Final Air Permit = Limits operation if EOR operator is out of service[376]<br>▪ Agreement has not be finalized with EOR Operator<br>▪ Class VI UIC permit has not been obtained |

364 Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf

365 Unless noted CCS data from: Ackiewicz

366 Unless noted Project Status from: Ackiewicz.

367 76 Fed. Reg. 60478 (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.

368 www.netl.doe.gov/publications/proceedings/11/co2capture/presentations/4-Thursday/25Aug11-Kirksey-Summit-Carbon%20Capture%20using%20Rectisol.pdf

369 http://newsroom.cpsenergy.com/blog/traditional-fuels/coal-traditional-fuels/cps-energys-ppa-texas-clean-energy-project-expired-dec-31/ (accessed Feb 24, 2014)

370 www.texascleanenergyproject.com/news-room/ (accessed Feb 24, 2014)

371 Air Permit #92350 and PSDTX1218 (2010). Texas Commission on Environmental Quality

372 Based on a review of project and agency websites

373 76 Fed. Reg (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.

374 HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf

375 HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf

376 Final Air Permit. (2013). San Joaquin Valley APCD.

## Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

### EPA Referenced CCS "development" or "demonstration" Projects

| EPA Reference | Unit Type[377] | CCS[378] | Project Status[379] | Comments |
|---|---|---|---|---|
| W.A. Parish (NRG Energy) | PC (retrofit) Capture from 250MWe[380] | 1,400,000 tonnes/yr EOR | Securing Financing Startup 2016 | ▪ Air Permit = No $CO_2$ Limits[381]<br>▪ EIS Record of Decision[382]<br>➢ "DOE's [purpose is]...to demonstrate the feasibility of advanced coal-based technologies at a commercial-scale that capture and geologically sequester CO2 emissions." (p. 30902)<br>➢ "The data would be used to help DOE evaluate whether the deployed technologies could be effectively and economically implemented at a commercial scale" (Id)<br>➢ "use best efforts to achieve at least 90 percent capture during the demonstration period" (p. 30905)<br>▪ 35 month demonstration project for EIS requirements[383]<br>▪ No evidence that Class VI UIC permit has been obtained[384] |
| FutureGen 2.0 (Illinois) | PC oxy-combustion (retrofit) 168 MWg[385] | 1,000,000 tonnes/yr Geologic Storage | FEED Ongoing No Construction Startup ~ 2017 | ▪ No air permit has been issued. Unclear if application has been filed<br>▪ Negotiations not finalized to purchase parts of existing unit[386]<br>▪ Class VI UIC permits has not been issued.[387]<br>▪ EIS Record of Decision[388]<br>▪ "DOE's [purpose is]...to demonstrate the commercial feasibility of an advanced coal-based technology (oxy-combustion) that may serve as a cost-effective approach to implementing carbon capture at new and existing power plants." (p. 3578) |

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377 Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
378 Unless noted CCS data from: Ackiewicz
379 Unless noted Project Status from: Ackiewicz.
380 Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p. 3
381 Review of Related Air Permits. Texas Commission on Environmental Quality. (https://webmail.tecq.state.tx.us accessed Feb 24, 2014)
382 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project.
383 Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p.3
384 Based on a review of project and agency websites
385 79 Fed. Reg 3578. (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project
386 "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. R43028. p. 3
387 www.epa.gov/r5water/uic/index.htm
388 79 Fed. Reg (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project.

## Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

**EPA Referenced CCS "development" or "demonstration" Projects**

| EPA Reference in Proposed Rule | Comments |
|---|---|
| Mountaineer CCS Program (AEP) | ▪ Validation-scale (1.5% slip stream) project completed 2009-2011<br>▪ Not an integrated commercial scale electric generation CCS project<br>▪ See Section VIII.A. of AEP comments for more information<br>▪ Air permit has no $CO_2$ limits |
| Plant Berry CCS Program[389] (Southern Company) | ▪ Validation-scale (25MWe) CCS project<br>▪ Air permit has no $CO_2$ limits<br>▪ Not an integrated commercial scale electric generation CCS project |
| AES Warrior Run (Maryland) | ▪ "Warrior Run...has been capturing a small portion of its $CO_2$ emissions for use in the food and beverage industry since 2000.... [T]hese existing capture technologies are energy-intensive, making their application to coal-fired power plants and other industrial sources potentially costly. Scaling these existing processes up to a commercial level and integrating them with fossil fuel-based power generation currently poses technical, economic, and regulatory challenges."[390]<br>▪ Air permit has no $CO_2$ limits<br>▪ Not an integrated commercial scale electric generation CCS project |
| AES Shady Point (Oklahoma)[391] | ▪ $CO_2$ capture from a "small slip stream" to supply food industry<br>▪ Air permit has no $CO_2$ limits<br>▪ Not an integrated commercial scale electric generation CCS project |
| Searles Valley Minerals Soda Ash[392] | ▪ Not an integrated commercial scale electric generation CCS project |
| Vattenfall Plant (Germany) | ▪ 10 MWe oxy-combustion demonstration<br>▪ Not an integrated commercial scale electric generation CCS project |
| Captain Clean Energy Plant (Summit Power) /(Scotland)[393] | ▪ Proposed integrated coal-based generation/CCS project<br>▪ Currently only a conceptual project, at best |
| "another poly-generation plant" (Summit Power) | ▪ EPA references a news article quoting Summit Power as saying it "will also plan on announcing its second poly-generation IGCC capture project... following TCEP's financial close"[394]<br>▪ Currently only a conceptual project, at best |
| "one NGCC unit" with CCS | ▪ Not an integrated commercial scale electric generation CCS project<br>▪ See Section VIII.E. of AEP comments for more information |
| Global CCS Institute Database of CCS Projects | ▪ 60 Power Generation CCS projects listed: Only 2 are actively being constructed (Boundary Dam and Kemper); The balance are planned[395] |
| DOE/NETL CCUS Database[396] | ▪ Does not list any noteworthy CCS efforts beyond those specifically identified in the proposed rule. Much of the data appears dated. |

[389] Data from https://sequestration.mit.edu/tools/projects/plant_barry.html
[390] "Summary of Potential Carbon Capture, Use, and Storage (CCUS) Options for the State of Maryland." Maryland Department of Natural Resources. (May 2013) p. ES-1 to ES-2.
[391] Data from "As Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18520. p. 9
[392] Data from "As Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18520. p. 9
[393] Data from http://sequestration.mit.edu/tools/projects/captain.html
[394] http://ghgnews.com/index.cfm/summit-even-without-uk-demo-funding-project-will-move-forward/?mobileFormat=true
[395] www.globalccsinstitute.com/projects/browse (accessed February 24, 2014)
[396] http://www.netl.doe.gov/technologies/carbon_seq/global/database/

## Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

**Other EPA Referenced CCS-related "development" or "demonstration" Projects:**

| EPA Reference in Proposed Rule | Comments |
|---|---|
| Great Plains Synfuels Facility (Dakota Gasification Company) (North Dakota)[397] | ▪ Coal gasification plant that produces natural gas and other products<br>▪ Supplies $CO_2$ to Weyburn and Midale EOR<br>▪ <u>Not an integrated commercial scale electric generation CCS project</u> |
| Weyburn EOR Project (Canada)[398] | ▪ $CO_2$ geologic storage began in 2000<br>▪ 1,000,000 tonnes/yr $CO_2$ stored<br>▪ Concerns have been raised regarding $CO_2$ leakage from storage site<br>▪ <u>Not an integrated electric generation CCS project</u> |
| Sleipner (North Sea - Norway)[399] | ▪ $CO_2$ geologic storage began in 1996<br>▪ 1,000,000 tonnes/yr $CO_2$ stored<br>▪ $CO_2$ produced by natural gas processing unit<br>▪ $CO_2$ capture and storage project to avoid Norwegian $CO_2$ tax<br>▪ <u>Not an integrated electric generation CCS project</u> |
| Snohvit (Barents Sea - Norway) | ▪ $CO_2$ geologic storage began in 2008<br>▪ 700,000 tonnes/yr $CO_2$ stored<br>▪ $CO_2$ produced by natural gas processing unit<br>▪ <u>Not an integrated electric generation CCS project</u> |
| In Salah[400] (Algeria) | ▪ $CO_2$ geologic storage began in 2004; Suspended in 2011 due to concerns regarding the integrity of the seal<br>▪ 1,200,000 tonnes/yr $CO_2$ stored<br>▪ $CO_2$ produced by natural gas processing unit<br>▪ <u>Not an integrated electric generation CCS project</u> |
| SACROC[401] (Texsa) | ▪ Injection of primarily of anthropogenic $CO_2$ since 1972 for EOR<br>▪ Recycling of some $CO_2$ for additional EOR<br>▪ <u>Not an integrated electric generation CCS project</u> |
| Gorgon $CO_2$ Injection Project (Australia)[402] | ▪ Project under construction; Startup estimated in 2015<br>▪ 4,100,000 tonnes/yr $CO_2$ stored from natural gas processing plant<br>▪ <u>Not an integrated electric generation CCS project</u> |
| Collie-South West $CO_2$ Geosequestration Hub (Australia) | ▪ Potential project to geological store $CO_2$ from multiple sources<br>▪ Design work continues; No estimate for when/if project will start<br>▪ <u>Not an integrated electric generation CCS project</u> |

[397] Data from www.dakotagas.com/About_Us/index.html
[398] Data from http://sequestration.mit.edu/tools/projects/weyburn.html
[399] Data from https://sequestration.mit.edu/tools/projects/sleipner.html
[400] Data from https://sequestration.mit.edu/tools/projects/in_salah.html
[401] "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18500. pp. 15
[402] Data from http://sequestration.mit.edu/tools/projects/gorgon.html

# Appendix B

## Examples of Major Public and Private Assessments of CCS Development

## Appendix B – Examples of Major Public and Private Assessments of CCS Development

| Report/Organization | Date | State of CCS | Barriers to Commercially Acceptable CCS | Prospects for CCS Development |
|---|---|---|---|---|
| President Obama's Interagency Task Force on Carbon Capture and Storage. Report of the Interagency Task Force[403] | Aug. 2010 | "Current technologies could be used to capture $CO_2$ from new and existing fossil energy power plants; however, they are not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application." (p.50)<br><br>"CCS technologies...are not likely to be widely deployed at coal-fired power plants....without additional knowledge generated by research, development, and demonstration activities." (p.87) | "Though CCS technologies exist, "scaling up" these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges." (p.9)<br><br>"..barriers hamper near-term and long-term demonstration and deployment of CCS technology." (p.14)<br><br>"A concerted effort to properly address financial, economic, technological, legal, institutional, and social barriers will enable CCS to be a viable climate change mitigation option..." (p.8) | "Administration analyses of proposed climate change legislation suggest that CCS technologies will not be widely deployed in the next two decades..." (p.8)<br><br>"The focus of CCS RD&D is....to facilitate widespread cost-effective deployment after 2020." (p.9) |
| The National Coal Council (a Federal Advisory Committee to Secretary of Energy Chu). *Expedited CCS Development: Challenges & Opportunities*[404] | Mar. 2011 | "..a range of issues must be addressed before CCS processes are commercially acceptable for coal-based electric generating units. ...key development concerns include the fact that commercial-scale CCS processes have *not yet* been demonstrated on a coal-fired generating unit" (p.1) | "...the current CCS demonstration program in the [U.S.]...is not on pace to significantly advance CCS development in the near-term due to technical and equally non-technical obstacles.... Challenges to CCS development...can be broadly categorized into technical, financial, and regulatory areas." (p.1) | "At the current [development] rate, CCS technologies will continue to be in an early development stage by 2020." (p.64)<br><br>"Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050." (p.14) |
| DOE / NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update[405] | May 2011 | "...in their current state of development [the $CO_2$ capture technologies being used in industrial applications] are not ready for implementation on coal-based power plants" (p.4) | "[$CO_2$ capture] technologies are not ready for implementation on coal-based power plants [because] (1) they have not been demonstrated at the larger scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support $CO_2$ capture would decrease power generating capacity...; and (3) if successfully scaled-up, they would not be cost effective at their current level of process development." (p.4) | "It is anticipated that successful progression from laboratory- to full-scale demonstration will result in several of these [$CO_2$ capture] technologies being available for commercial deployment by 2030." (p.10) |
| DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap[406] | Dec. 2010 | "...cost-effective and efficient CCS technologies will need to be developed and demonstrated at full-scale prior to their availability for widespread commercial deployment." p. 5<br><br>"...at their current state of development these [$CO_2$ capture] technologies are not ready for implementation on coal-based power plants." (p.21) | "...advanced technologies developed in the CCS RD&D effort need to be tested at full scale in an integrated facility before they are ready for commercial deployment." (p.11) | "....the overall timeline for RD&D....involves pursuing advanced CCS technology from the fundamental / applied stage through pilot-scale so that full-scale demonstrations can begin by 2020. The RD&D effort will produce the data and knowledge needed to establish the technology base, reduce implementation risks by industry, and enable broader commercial deployment of CCS to begin by 2030." (p.10) |
| DOE / NETL Carbon Sequestration Program: Technology Program Plan[407] | Feb. 2011 | "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020." (p. 10) | "To accomplish widespread [commercial] deployment [of CCS by 2020], four program goals have been established:<br>(1) [reduce CCS related costs];<br>(2) [improve the] ability to predict $CO_2$ [geologic] storage capacity;<br>(3) develop technologies to demonstrate that...$CO_2$ remains in the injection zones;<br>(4) complete Best Practices Manuals...for site selection, characterization, site operations, and closure practices." (p. 10) | "Only by accomplishing these goals [of the DOE Carbon Sequestration Program] will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades." (p.10) |

[403] "Report of the Interagency Task Force on Carbon Capture and Storage." Aug 2010. www.fe.doe.gov/programs/sequestration/ccs_task_force.html
[404] "Expediting CCS Development: Challenges and Opportunities." Mar 2011. Library of Congress Catalog #2011926623. www.nationalcoalcouncil.org
[405] Department of Energy / National Energy Technology Lab. May 2011. www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/
[406] Department of Energy / National Energy Technology Lab. Dec 2010. www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[407] Department of Energy / National Energy Technology Lab. Feb 2011. www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf

### Appendix B – Examples of Major Public and Private Assessments of CCS Development

| Report/Organization | Date | State of CCS | Barriers to Commercially Acceptable CCS | Prospects for CCS Development |
|---|---|---|---|---|
| 2014 DOE/NETL Carbon Capture website[408] | Accessed April 2014 | "Commercially available first-generation $CO_2$ capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants..." (home page of website) | "[Commercial-scale CCS technologies for coal-based power plants]...have not been demonstrated at appropriate scale, require approximately one-third of the plant's steam and power to operate, and are cost prohibitive." (home page of website) | "The success of...[current R&D efforts] in developing these technologies will enable cost-effective implementation of carbon capture and storage (CCS) throughout the power-generation sector..." (home page of website) |
| "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy"<br>Congressional Research Service[409] | Feb 2014 | "To date...there are no commercial ventures....that capture, transport, and inject industrial-scale quantities of $CO_2$ solely for the purposes of carbon sequestration" (summary page) | "The challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States." (p. 6)<br><br>"Development Phase projects will provide a better understanding of regulatory, liability, and ownership issues associate with commercial scale CCS. These nontechnical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting $CO_2$ safely and in perpetuity are resolved." (p. 23) | "..the coal RD&D program is focused on achieving results that would allow for an advanced CCS technology portfolio to be ready by 2020 for large-scale demonstration." (pp 6-7) |
| "A Summary of Potential Carbon Capture, Use, and Storage Options for the State of Maryland"<br>Maryland Department of Natural Resources[410] | May 2013 | "CCUS is not fully developed to a commercially available scale" (p. 1-1)<br><br>"Current and emerging technologies may be considered to capture $CO_2$ from new and existing fossil energy power plants.... However, these technologies have not been demonstrated at the scale necessary to establish confidence for widespread power plant application." (p. 3-7) | "Scaling these existing [carbon capture] processes up to a commercial level and integrating them with fossil-fuel power generation currently poses technical, economic, and regulatory challenges" (ES-2)<br><br>"..because CCUS has not been widely deployed, there is uncertainty about how environmental statutes will apply...and if the current framework is adequate for both near- and long-term deployment of CCUS." (p. 2-7)<br><br>"developing a transportation infrastructure to accommodate future CCUS projects may encounter challenges regarding technology, cost, regulation, policy, right-of-way, and public acceptance." (p. 4-1) | "Carbon capture technologies necessitate additional research, development, and demonstration to reach commercial scale" (p 6-1) |
| "Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions"[411]<br>U.S. Government Accountability Office | June 2010 | "while components of CCS have been used commercially in other industries, their application remains at a small scale in coal power plants" (p. 2) | "Use of [CCS] is...contingent on overcoming a variety of economic, technical and legal challenges. In particular, with respect to CCS, stakeholders highlighted the large costs to install and operate current CCS technologies, the fact that large scale demonstration of CCS is needed in coal plants, and the lack of...a legal framework to govern liability for permanent storage of large amounts of $CO_2$" (p. 2) | "Commercial deployment of CCS is possible within 10 to 15 years" (p. 2) |
| "Carbon Capture: A Technology Assessment"<br>Congressional Research Service[412] | Nov 2013 | "at present there are still no full-scale applications of $CO_2$ capture on a coal-fired or gas-fired power plant" (p.2) | "the major drawbacks of current [$CO_2$ capture] processes are their high cost and the large energy requirements for operation." (p. 2) | "Technology roadmaps developed by governmental and private-sector organizations...anticipate that $CO_2$ capture will be available for commercial deployment at power plants by 2020.... Such projections acknowledge, however, that this will require aggressive and sustained efforts to advance promising concepts to commercial reality." (p. 2) |

[408] www.netl.doe.gov/research/coal/carbon-capture
[409] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service.
[410] "A Summary of Potential Carbon Capture, Use, and Storage Options for the State of Maryland." May 2013. Power Plant Research Program. Maryland DNR. DNR Publication No. 12-5162013-645.
[411] www.gao.gov/products/GAO-10-675
[412] "Carbon Capture: A Technology Assessment" (Nov 2013). R41325. Congressional Research Service. www.fas.org/sgp/crs/misc/R41325.pdf

# Appendix C

# CCS Lessons Learned Report AEP Mountaineer CCS II Project Phase 1

# CCS LESSONS LEARNED REPORT
# American Electric Power
# Mountaineer CCS II Project
# Phase 1

**Prepared for**

**The Global CCS Institute**

**Project # PRO 004**

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4. FRONT-END ENGINEERING & DESIGN REPORT TO GLOBAL CCS INSTITUTE

# 1. SYNOPSIS

The purpose of this report is to share select lessons learned, insights and exemplary practices from American Electric Power's Phase I – Project Definition activity associated with the Carbon Capture and Storage (CCS) system planned for installation at the company's Mountaineer Plant, located in New Haven, West Virginia, USA under US Department of Energy Cooperative Agreement No. DE-FE002673. Notwithstanding American Electric Power's (AEP) decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale CCS project.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction, operations, and process related) from the 20 MWe pilot Product Validation Facility (PVF) project for both the carbon dioxide ($CO_2$) capture and storage systems. The design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, process flow diagrams, P&IDs, etc.

The work completed in Phase I continues the advancement of Alstom's CAP technology toward commercial demonstration at the intended scale. The completed front-end engineering and design package also provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere. The lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

# 2. EXECUTIVE SUMMARY

With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took an early leadership role in exploring the feasibility of retrofitting its coal-fired fleet with $CO_2$ capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future CO2-limiting policies in the US and abroad. Among other things, AEP engaged in a cost sharing agreement with the US Department of Energy (DOE) in 2003 to determine the geologic feasibility of storing $CO_2$ in deep saline reservoirs in the Ohio Valley. Based on the favorable results of the geologic characterization project, AEP selected the Alstom's Chilled Ammonia Process in 2007 for testing of their $CO_2$ capture technology at a 20 MWe pilot scale. Known as the Product Validation Facility, the project included carbon dioxide injection and deep saline storage. The 2009 proposed scale up of Alstom's Chilled Ammonia Process to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy aimed at curbing $CO_2$ emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer Commercial CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend further work following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning $CO_2$ emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions that also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

As a part of any project close-out, projects and engineering groups within AEP's generation business unit routinely document lessons learned. Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. While a number of lessons learned were documented during project execution, most of the lessons learned were documented and compiled at the end of Phase I in a lessons learned meeting that followed an advance survey of project team members for lessons learned inputs. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. Lessons learned inputs were aggregated into three broad categories: Overall Project General, $CO_2$ Capture Effort and $CO_2$ Storage Effort.

The lessons learned discussions contained herein primarily pertain to the Mountaineer commercial scale CCS project. However, given the historical work leading up to and inputting to the commercial scale project a number of discussions draw on AEP's earlier experiences.

While a select number of notable lessons learned, insights, and exemplary practices are highlighted in this presentation, numerous others are shown in an Appendix to this report. The documented lessons learned, insights, and exemplary practices should serve a future project team, if and when the project resumes, others working on DOE funded projects and other CCS projects in general.

# 3. INTRODUCTION

## 3.1 About Lessons Learned

Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. The projects and engineering groups, within AEP's generation business unit, routinely utilize lessons learned processes in execution of their projects. Through documentation and dissemination of lessons learned, project teams and organizations learn from and avoid the reoccurrence of miss-steps. Additionally, and equally as important, lessons learned processes may extend to the identification of exemplary practices and recommended process improvements that help mature performing teams and organizations, increasing their value to and contributing to the bottom lines of their companies.

## 3.2 Lessons Learned Process

As noted above, lessons learned are routinely documented in the execution of projects. Project teams may be asked to document lessons learned following a specific incident, action or activity. Alternatively, lessons learned are compiled following completion of a short term project of a year or less; or, in the case of a long term project performed over multiple years, they may be compiled following the completion of a project phase (e.g. initial front-end engineering and design, detailed engineering, construction, and start-up and commissioning). As a phased project, the Mountaineer Commercial Scale CCS project (MT CCS II) held a lesson learned meeting following a survey of project team members for inputs in advance of the meeting. Inputs were requested for lessons learned, exemplary practices and process improvements. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input to and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. The lessons learned, exemplary practices, and recommended process improvements were distributed to the participants and input to AEP's lessons learned data base repository.

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on related carbon storage projects that first started in 2003; descriptions of those projects are contained in Section 3.3.

## 3.3 Historical Evolution to Current Project

AEP has been actively involved in the development of CCS technology over the past eight years. AEP's initial involvement in the development of CCS began in 2003 with the Ohio River Valley $CO_2$ Storage Project; US DOE's National Energy Technology Laboratory (NETL) sponsored the project under Contract No. DE-AC26-98FT40418. The project included the drilling, sampling, and testing of a deep well combined with a 2D seismic survey to characterize local and regional geologic features at AEP's Mountaineer plant. The work completed within the project laid the groundwork for site selection of the PVF based on its very detailed geologic characterization study.

In March 2007, AEP signed an agreement with Alstom to validate its Chilled Ammonia Process (CAP) technology via scale up to a 20-MWe Product Validation Facility (PVF). Alstom had previously constructed and operated a 1.7-MWe pilot scale CAP capture facility at the We Energies Pleasant Prairie Power Plant. The flue gas volume of the slip stream for the PVF is equivalent to the flue gas generated from a 20 MWe coal fired power plant. The PVF was designed to capture and store approximately 100,000 metric tons of $CO_2$ annually.

Captured $CO_2$ from the PVF was injected via two onsite wells into two geologic formations (Rose Run sandstone and Copper Ridge dolomite) at a depth of approximately 1.5 miles below the plant site. One injection well and three deep monitoring wells were drilled within the power plant property between 2008 and 2009. The characterization well, previously drilled in 2003 was re-worked and transformed into one of the two injection wells. The PVF provided critical data to support the design and engineering of the MT CCS II project.

In August 2009, AEP submitted an application to Department of Energy (DOE) to demonstrate the commercial viability for retrofitting the Mountaineer plant with a 235-MWe nominal carbon capture and storage facility, building on the work of the DOE supported Ohio River Valley $CO_2$ Storage Project, and including the non-DOE funded PVF. In December 2009, DOE announced the selection of the Mountaineer Commercial Scale Carbon Capture and Storage Project for funding under Round Three of the DOE's Clean Coal Power Initiative.

## 3.4 Project Objectives & Scope

AEP's objective for the MT CCS II project is to design, build, and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization (FGD) system at the Mountaineer Plant, a 1,300 MWe coal-fired generating station located in New Haven, West Virginia. The CCS system is designed to capture 90% of the $CO_2$ from the incoming flue gas using the Alstom's CAP and compress, transport, inject and store 1.5 million metric tons per year of the captured $CO_2$ into deep saline reservoirs.

AEP and its integrated project team, including Alstom, Battelle and WorleyParson successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project in accordance with US DOE Cooperative Agreement No. DE-FE002673, which provided 50% cost sharing to the project. Phase I of the project's cooperative agreement called for, among other things: the completion of front-end engineering and design (FEED); the development of an Environmental Impact Statement in accordance with the National Environmental Process Act (NEPA); and the identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, process flow diagrams, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote $CO_2$ storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

## 3.5 Scope of Lessons Learned

The lessons learned discussions contained herein primarily pertain to the MT CCS II project. However, given the historical work leading up to and inputting to the MT CCS II project a number of discussions draw on AEP's earlier experiences. Specifics of lessons learned relating to Alstom's Chilled Ammonia Process technology are not addressed in this report due to the proprietary nature of that information; generalities are however noted consistent with the referenced topical project reports previously prepared for the Global CCS Institute. Specifics of a number of lessons learned pertaining to the work on $CO_2$ storage systems are however shared in this report.

While this report is titled a CCS Lessons Learned Report, the discussions contained herein also include insights and advice and discussion of exemplary practices.

# 4. LESSONS LEARNED, INSIGHTS AND EXEMPLARY PRACTICES

## 4.1 Organization of Discussion

The lessons learned discussions, insights, exemplary practices and other advice shared within this section are organized along broad classifications of: Overall Project General, Carbon Dioxide Capture Systems, and Carbon Dioxide Storage Systems. Select lessons learned are noted and discussed, while other lessons learned are listed in appendices. Within the broad classifications, the lessons learned discussed that are listed in the appendices may be further subcategorized by subject area (e.g. engineering/technical, regulatory, environmental, construction, project management, communications, etc).

The format employed for presenting the subject mater includes:

- A statement or description of the lessons learned, insight or exemplary practice;
- A recommendation for any listed lesson learned; and
- Discussion, as applicable for understanding and context for the lesson learned, insight or exemplary practice.

The lessons learned insights and exemplary practices listed and discussed in the sections to follow are judged to be some of the more significant issues worthy of listing and discussion; they are however randomly listed within the broad categories and are not shown in any prioritized ranking.

## 4.2 Overall Project

### 4.2.1 Lessons Learned

#### 4.2.1.1 LACK OF FEDERAL LEGISLATION RELATED TO $CO_2$ EMISSIONS

**Recommendation** - Dissolve the existing cooperative agreement at the appropriate project phase decision point and postpone project activities.

**Discussion** - At the Phase I decision point to DOE, AEP communicated its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations limiting $CO_2$ emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. The Waxman-Markey Bill even passed the House but later failed to pass the Senate. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

#### 4.2.1.2 PREPARATION OF THE ENVIRONMENTAL IMPACT STATEMENT (EIS) REQUIRED MORE UPFRONT TECHNICAL OR ENGINEERING INFORMATION THAN WAS INITIALLY AVAILABLE

**Recommendation -** Start engineering and hire the National Environmental Policy Act (NEPA) contractor as soon as practicable. Build 18 to 24 months into the project schedule for the NEPA process**.**

**Discussion -** Compiling information and having an Environmental Impact Statement (EIS) prepared is an intensive effort that requires the completion of some engineering to start the EIS development process. Environmental Impact Statements written around processes that are somewhat first-of-a-kind or new can add challenges to the NEPA process as many of the analyses and evaluations in the EIS require significant information from the process or technology. Since commercial scale CCS had not yet been demonstrated in practice, much of the technical information was based on calculated values, modeled effects, and assumptions.

#### 4.2.1.3 CARBON DIOXIDE CAPTURE RETROFIT SYSTEMS MAY NOT BE PRACTICABLE FOR PLANT SITES LACKING AVAILABLE AREA FOR THE PROCESS EQUIPMENT

**Recommendation** – Recognize that carbon capture retrofit installations require significant space for installation and operations.

**Discussion** – The design for the MT CCS II project covers about 13 acres of plant property adjacent the existing 1300 MW unit. As a first-of-a-kind (FOAK) retro-fit facility, the design for the project includes buildings for visitor presentations, administrative staff, a laboratory and added warehouse space. The need for the additional buildings may or may not be applicable to other installations, based on their site specific circumstances. That being said, the amount of space needed for the retrofit project was a significant revelation to AEP; fortunately the Mountaineer plant site is not constrained by a lack of available space.

#### 4.2.1.4 THE PROJECT TEAM GAINED A GREATER APPRECIATION FOR THE BENEFITS OF PERFORMING EARLY HAZARDS ANALYSES AND CONSTRUCTABILITY REVIEWS

**Recommendation** - Incorporate hazards analyses and constructability reviews in FEED activities.

**Discussion** – AEP's Engineering, Projects and Field Services organization continually strives to improve its recognition of hazards and incorporation of safety into its designs. Additionally, efforts to involve construction personnel in constructability reviews during front end engineering & design has had limited success, primarily due to limited resources availability. As a FOAK project with many perceived hazards and concerns for first time construction of such a project, AEP and its integrated project team focused significant effort and resources to identify and address hazards and constructability issues. The effort and time spent proved far more valuable than anticipated contributing to, among others: the early identification and the efficient addressing of hazards during the FEED process; early identification of constructability concerns that led to cost savings opportunities; and a more robust cost estimate and construction schedule.

### 4.2.2 Insights

#### 4.2.2.1 IN A FOAK APPLICATION, TRY TO INNOVATE FROM PROVEN TECHNOLOGIES

**Discussion** – FOAK applications or projects inherently carry a number of unknown uncertainties or risks, or in other words you don't know what you don't know until it happens. It's important to limit uncertainties or risks associated with new or unproven technologies without track records. A significant portion of the process equipment making up the CAP is readily used in the petrochemical industry. While scaling up the equipment design often led to a multiple process "train" approach within the broader process, the equipment considered for MT CCS II was not un-proven in industrial or petrochemical applications.

#### 4.2.2.2 THE GREATEST COST RISKS FOR CCS PROJECTS MAY LIE IN THE STORAGE SIDE OF SUCH PROJECTS

**Discussion** – AEP and its integrated project team performed a critical review of the MT CCS II project cost estimate for application of risk based project contingency. AEP examined the $CO_2$ capture system cost estimate, and generally felt that the estimate contained more opportunities for cost savings than risks of cost increases. The greatest uncertainties and corresponding risks for cost increases were in the carbon storage side of the project, principally due to uncertainties associated with interpretation and application of the new Class VI Underground Injection Control (UIC) permit regulations for injection, monitoring and post closure care of carbon storage sites. Additional detailed discussion for this insight is contained in the Front-end Engineering and Design report on the MT CCS II project prepared for Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

### 4.2.3 Exemplary Practices

#### 4.2.3.1 HIGH RISK AND FOAK PROJECTS AND/OR PROGRAMS NEED TO BE CAREFULLY MANAGED FROM INCEPTION THROUGH PILOT TESTING AND COMMERCIAL DEMONSTRATION WITH STRATEGICALLY PLACED DECISION POINTS AND PHASE GATE OFF-RAMPS

**Discussion** – With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took a leadership role in exploring the feasibility of retrofitting its coal-fired fleet with $CO_2$ capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future $CO_2$-limiting policies in the US. As noted in the introduction, AEP first engaged in a cost sharing agreement with the DOE to determine the geologic feasibility of storing $CO_2$ in deep saline reservoirs in the Ohio

Valley, home to a number of AEP coal-fired generating plants. Based on the favorable results of the geologic characterization project, AEP selected the Alstom CAP for pilot testing of carbon dioxide capture and included $CO_2$ storage in the PVF project. The scale up of Alstom's CAP to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy on limiting $CO_2$ emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points, allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and collective decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend further work following the completion of Phase I.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

#### 4.2.3.2 COMMUNICATE OFTEN WITH THE PUBLIC

**Discussion** – Be sure to develop a communications plan for your project and ask plant employees that live in nearby communities to review and comment on it before rolling it to the public. Plan for and conduct meetings with local government and public officials before the start of major work on site; include public open houses and/or town hall meetings to describe the project and address any concerns. AEP held annual town hall meetings to update community leaders on project status and plans for the upcoming year. Example presentations or discussions might include among others, an exhibit showing the type of truck and geophone used to perform 2D seismic studies (e.g. noise from pounding the ground and tracking energy waves) and a heads-up of crew schedules for walking down proposed $CO_2$ pipeline transport corridors.

## 4.3 Carbon Dioxide Capture

### 4.3.1 Lessons Learned

#### 4.3.1.1 CARBON DIOXIDE CAPTURE SYSTEMS ARE CHEMICAL PLANTS THAT HAVE A DIFFERING OPERATING PHILOSOPHY THAN ELECTRIC POWER PLANTS

**Recommendation** – The $CO_2$ capture technology provider and electric utility owner need to recognize and address operational philosophy differences and process dynamics limitations early in the design process.

**Discussion -** Power plants and chemical plants have differing operational philosophies. Examples include: 1) chemical plants produce a uniform product from a uniform feed stock whereas power plant electrical energy production is based on demand closely tied to weather; 2) chemical plants have stable production rates with consistent production schedules whereas power plants have frequent power output adjustments based on time of day and load following; and 3) coal-fired power plants have a variable fuel feedstock whereas variability of feedstock to chemical plants is minimized to reduce impacts. Additional issues include: access, maintainability related to outage durations, and safety policies that added to cost; see the referenced CCS Integration report for additional detailed discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

#### 4.3.1.2 SOURCING AND QUALITY OF STEAM IS IMPORTANT

**Recommendation** – Carefully consider the extraction source(s) of steam relative to the needs for the $CO_2$ capture retrofit system; depending on the size of the carbon dioxide capture system, a stand alone or independent steam supply source may be more desirable.

**Discussion** – As discussed at length in the CCS Integration Report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team decided to extract steam at two different pressure levels and utilize throttling valves for supply of steam to the carbon dioxide capture regeneration and process stripping systems. The selection points and quality of steam supply met the needs for the system at the intended scale-up size. However, if one were to design a commercial scale system capable of treating the entire flue gas discharge, and independent steam supply source would need to be considered. It must be understood that selection of the steam source is highly site-specific and project-specific. Because this was a slipstream demonstration project, AEP was reluctant to accept significant modifications to the steam turbine that could have impacted future operations once the CCS project was completed. That design criteria then factored into the overall decision of where to extract steam.

#### 4.3.1.3 UNCLEAR CRITERIA FOR OPERATIONS VERSUS CAPITAL COSTS CAN LEAD TO REANALYSIS AND DELAY.

**Recommendation** - Establish criteria for operating versus capital costs early in the project.

**Discussion** – Early consideration of evaluation criteria (e.g. reliability, maintainability and availability) by owner and technology provider teams helps avoid later focus on the wrong driver for a design decision.

#### 4.3.1.4 INSURE THAT PRELIMINARY EQUIPMENT SIZING CAN BE PRACTICABLY FABRICATED AND SHIPPED TO SITE.

**Recommendation** – Work with one or more potential equipment suppliers during initial design.

**Discussion** – FOAK system projects, in a scale-up stage will lead to new sizing or reconfiguration of equipment. Equipment suppliers will likely have insights regarding practical limitations of sizing and/or cost savings ideas for reconfiguration of equipment subsystems or components. The challenge to the FOAK technology and/or overall project owner is to determine when it may be in the best interests of the project to involve equipment suppliers in early design discussions, including the need to compensate them for resources utilized in providing the inputs.

#### 4.3.1.5 A DEDICATED EXHAUST STACK MAY BE PREFERRED AND/OR REQUIRED

**Recommendation** – Carefully consider the need for a new dedicated exhaust stack, including the lead time needed for permitting.

**Discussion** – As discussed in more detail in the CCS Integration report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team considered use of the existing plant stack, construction of a new stack and also possible use of the existing plant hyperbolic cooling tower as an exit point for the treated gas stream. While the team initially recommended a new dedicated stack, uncertainties and lead times associated with modeling and permitting of a new stack became a disincentive. The team returned treated gas back to the existing plant stack as a basis for the project cost estimate. However, for treating higher percentages of flue gas, a dedicated exhaust point may be required as the technical difficulties surrounding mixing of flue gas streams and gas stream temperatures may become a concern.

#### 4.3.1.6 GRAY WATER MANAGEMENT IS A SIGNIFICANT CHALLENGE

**Recommendation** – Turn gray water into a marketable product

**Discussion** – The gray water by-product bleed stream, containing ammonium sulfate, can be made into a marketable product as feedstock for manufacture of fertilizer. For Mountaineer's gray water to be considered desirable, the concentration of ammonium sulfate solution needed to be at least 40%. Contacting potential end users early in the design process to better understand the types of products they can utilize can prove beneficial. As an aside, fresh water make-up for evaporation and losses did not require additional make-up capacity at Mountaineer. Again this is project specific, but avoiding the expense and balance of plant related impacts of adding make-up water capacity were significant factor in the overall design process.

#### 4.3.1.7 AEP EVALUATED A NUMBER OF REAGENTS FOR THE CHILLED AMMONIA PROCESS

**Recommendation** - Anhydrous Ammonia is the optimal reagent for the CAP.

**Discussion** – The project team evaluated a number of reagents for use in the CAP refrigeration system. The chilled ammonia process uses ammonia solution as chemical solvent to remove $CO_2$ from the flue gas. Ammonia is the single natural refrigerant being used extensively in industrial applications for its good thermodynamic and thermophysical characteristics. While ammonia is an excellent refrigerant, it is also a hazardous substance. Although hazardous, there are well established practices, common in industry, for the safe handling of anhydrous ammonia. The evaluation and comparisons carried out by the project team showed that an ammonia refrigeration system is optimal for the Mountaineer CCS II project. This system has the lowest energy consumption (highest efficiency) and the lowest installed capital cost, with minimal environmental impact with respect to ozone depletion, greenhouse effect, or global warming.

#### 4.3.1.8 ASSUMPTION OF HIGH $CO_2$ INJECTION WELL PRESSURES

**Recommendation** – $CO_2$ compression to an intermediate pressure, followed by variable speed pumping to the final injection pressure offers the greatest flexibility and efficiency over the life of the system as compared to full compression to the maximum expected injection pressure.

**Discussion** – Injection well pressures in the range of 1200 – 1500 psi range are expected early in the life of the target injection wells. Maximum injection pressure into the geological formations targeted for this project is expected to be 3000 psi. It should be noted that the allowable maximum injection pressure depends on the permitting agency and the fracture gradient of the reservoir and the cap rock. See the referenced CO2 Compression Report for additional discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

### 4.3.2 Insights

#### 4.3.2.1 BUILD FLEXIBILITY INTO PLANT INTERFACE POINTS TO ALLOW FOR AND/OR ACCOUNT FOR UPSET CONDITIONS.

**Discussion** – The CCS integration report, furnished to Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project> discusses at length AEP's approach for integrating FOAK retro-fit technologies and the need to build flexibility into plant interface points. Design basis for plant interface points can be refined later based on operating experience.

### 4.3.3 Exemplary Practices

#### 4.3.3.1 INVOLVE APPROPRIATE PLANT PERSONNEL IN ALL DISCUSSIONS SURROUNDING CRITICAL INTERFACE POINTS (E.G. STEAM TURBINE, RIVER WATER INTAKE, AND OTHER CRITICAL PROCESSES)

**Discussion** – Plant personnel have greater awareness for and key insights regarding operational flexibility of their plant systems. Involvement of plant personal from the onset of the project contributed to a higher confidence of the design basis, improved communication of ideas, and minimized obstacles to plant understanding and acceptance.

#### 4.3.3.2 THE PROJECT TEAM'S USE OF A 3D MODEL DURING PRELIMINARY PROJECT DESIGN PROVIDED NUMEROUS BENEFITS

**Discussion** – The 3D model developed for the project proved to be invaluable to the integrated project team. As the model was developed, it was reviewed on a monthly basis by project team members representing, among others: construction, engineering, plant personnel, and project management. The model not only helped with understandings of equipment sizing and relationships to existing plant infrastructure, but it also helped the team develop a detailed materials list and robust cost estimate; as an example, the team was able to account for piping sizes down to a 2-1/2 inch (6.35 cm) diameter. The model also aided project constructability reviews. Overall, the project team felt that the use of the model increased everyone's confidence in the final project cost estimate.

#### 4.3.3.3 AEP AND ALSTOM COLLOCATED ENGINEERING PERSONNEL AND UTILIZED INTEGRATED PROCESS DESIGN WORKSHOPS

**Discussion** – The start of design for the MT CCS II project overlapped with the operation of the PVF. As a result, lessons learned from the PVF were still being revealed and/or compiled during early MT CCS II design activity. AEP and Alstom decided to collocate engineering and plant personnel, alternating in offices both in the US and in Europe, to speed an in depth understanding and application of the lessons learned from the PVF. The process design workshops helped speed the integrated project team's collective understanding of capture subsystems in a way that allowed for transparency and buy-in from plant personnel that ultimately would be tasked with operation of the systems. The process design workshops also contributed to a higher level of confidence for the overall system design.

## 4.4 Carbon Dioxide Storage

### 4.4.1 Lessons Learned

#### 4.4.1.1 $CO_2$ INJECTION AND MONITORING WELLS ARE NOT "BUSINESS AS USUAL" FOR ANY REGULATOR.

**Recommendation** - Partner with regulators and others as needed early in the permitting process.

**Discussion** - Underground Injection Control (UIC) regulations, promulgated by the US Environmental Protection Agency (EPA) are new and may be unfamiliar to state regulators. States targeted for CCS projects will also need to develop their own regulations to comply with US EPA requirements before they can be authorized to process and permit $CO_2$ storage projects.

#### 4.4.1.2 THE PROJECT TEAM DID NOT HAVE AN APPRECIATION FOR NECESSARY LEAD TIMES TO SECURE PROPERTY ACCESS RIGHTS FOR LOCATING $CO_2$ TRANSPORT PIPELINES.

**Recommendation** – Involve land management professionals early in the development of any project schedule.

**Discussion** – The project team did not have an appreciation for the lead times necessary to secure property access rights, causing some schedule delay. Land management personnel should be consulted when developing the Level I or II inputs to the overall project schedule. In a related matter, project team incorrectly assumed that the location of transport pipe lines within right-of-ways for transmission lines would lessen permitting needs.

#### 4.4.1.3 THE DRILLING SCHEDULE DID NOT ACCOUNT FOR COMMON RISK FACTORS THAT CAN IMPACT THE PLANNED SCHEDULE OF COMPLETION.

**Recommendation** – Acknowledge risk factors in the drilling operation and incorporate them into the schedule.

**Discussion** – The drilling of the BA-02 characterization well proceeded on a tight schedule that in hind site was optimistic and did not consider common risk factors associated with drilling deep wells. Example risk factors might could include among others: failed parts and machinery and the need to maintain adequate spare parts onsite or in close proximity, encountering fluid when drilling on air, encountering excessive fluids in formations, loss of circulation during cementing, fishing tools out of a bore hole, etc. Project teams should work with their drilling crews to anticipate possible risk factors and their probabilities for occurrence and build an appropriate level of contingency into the overall schedule for drilling, and project schedule as applicable.

#### 4.4.1.4 NEW GEOLOGIC HORIZONS MAY AVAIL THEMSELVES AS BONA FIDE $CO_2$ STORAGE TARGETS

**Recommendation** – Consider, to the extent practicable, the drilling of multiple characterization wells over an expanded area.

**Discussion** – Based on the drilling of the BA-02 characterization well and the subsequent down hole testing, the project team confirmed the Lower Copper Ridge zone was viable beyond the area immediately surrounding the Mountaineer Plant. Prior to work at Mountaineer, this zone was not previously understood to have characteristics suitable for $CO_2$ storage.

#### 4.4.1.5 GEOPHYSICAL TECHNIQUES SUCH AS SURFACE SEISMIC HAVE RESOLUTION LIMITATIONS

**Recommendation** – Reservoir testing is crucial during the characterization process.

**Discussion** – Surface seismic techniques cannot resolve thin horizons. The formations in the Mountaineer plant area are only approximately 30 ft (10 m) thick. Detailed log analyses (which have high resolution of approximately 1ft) and subsequent hydrologic testing of the target reservoirs were crucial in calculating the storage potential of the formation.

### 4.4.2 Insights

#### 4.4.2.1 INSURE THAT STATE LEVEL POLICIES ARE IN PLACE TO SUPPORT $CO_2$ INJECTION AND STORAGE; LEAD TIMES TO DO SO CAN SPAN MANY YEARS.

**Discussion** - $CO_2$ injection and storage could become cost prohibitive without state level policies, in the form of enabling legislation and regulations that frame the responsibilities and rights of the entities that inject $CO_2$ and adjacent property owners, respectively. State policies should address, from among other issues: financial responsibility, use of pore space, property rights, liability, eminent domain and permitting fees. Additionally, project teams need to consider the possible migration of injected $CO_2$ into other regulatory jurisdictions (i.e. adjacent states), as many coal-fired electric utility plants are located along rivers that form boundaries with other state regulatory jurisdictions.

The lead time necessary to develop state level policies, in the form of legislation and regulations can approach three to four or more years, depending on the extent of stakeholder interest and the overall priorities of state executive and legislative branches. For example, AEP has been working with West Virginia policy makers and other stakeholders on CCS issues for over four (4) years. During the 2009 legislative session, the West Virginia Legislature passed a bill acknowledging that it is in the public interest to advance the implementation of carbon dioxide capture and sequestration technologies into the state‘s energy portfolio. Recognizing the administrative, technical and legal questions involved in developing this new technology, the Code authorized the West Virginia Department of Environmental Protection Secretary to establish a Carbon Dioxide Sequestration Working Group (Working Group). The Working Group was charged with studying all issues related to the sequestration of carbon dioxide and to submit a preliminary report to the Legislature on July 1, 2010, followed up by a final report on July 1, 2011. The preliminary and final reports were delivered to the legislature. The final report, however, addresses, among other things recommended legislation to help encourage the widespread use of CCS in West Virginia. Proposed legislation still needs to be introduced and considered by the legislative body; a process that can take one or more years to complete.

#### 4.4.2.2 LEADING CCS PROJECTS NEED TO ACCOUNT FOR UNCERTAINTY WITH FIRST TIME APPLICATION OF UNDERGROUND INJECTION CONTROL (UIC) PERMITTING GUIDELINES.

**Discussion** – An initial Class VI UIC permit application for a CCS project has yet to be submitted and approved by any state regulatory jurisdiction within the US. Initial review and approval of first time permit applications in any state could become subject high stakeholder interest and prolonged agency review, leading to schedule delay. Additionally, uncertainty regarding the number of shallow, intermediate and deep monitoring wells that might be required by a first UIC permit issuance must be accounted for in project cost estimate assumptions and risks until such time that a UIC permit is received.

#### 4.4.2.3 LOOK FOR OPPORTUNITIES TO PURCHASE PREVIOUSLY COMPLETED 2D SEISMIC STUDIES IN AN AREA OF INTEREST.

**Discussion** – AEP purchased two 2D seismic lines to enhance its understanding of the regional geology, at a cost savings to the project. AEP also began to appreciate the potential to partner with other area projects that may be drilling in the area (e.g. shale gas exploration). Example partnering arrangements might include exchanging logging data, funding additional drill rig time and effort to perform various optional characterization tests at other nearby drilling sites, etc.

#### 4.4.2.4 CONSIDER THE NEED TO ESTABLISH SITE SELECTION CRITERIA TO EVALUATE PROPERTIES FOR THE WELLS AND PIPELINE CORRIDORS.

**Discussion** – AEP's selection of candidate well injection sites focused on: property owned by the company in West Virginia; locations which required minimal right-of-way interferences for pipelines and access to the sites; and sites within relative close proximity to the Mountaineer plant. In the course of building a cost estimate for the project, it became apparent that some sites, on closer inspection, had significant developmental costs for access. In retrospect, the project team may have benefitted from having developed site selection criteria based on input from a multi-discipline team (e.g. engineering, environmental, geology, legal, project management). Future projects should consider the need to establish site selection criteria and apply the criteria as early as possible in the conceptual design phase of the project.

### 4.4.3 Exemplary Practices

#### 4.4.3.1 FORM AND UTILIZE A GEOTECHNICAL EXPERTS ADVISORY GROUP

**Discussion** - Public acceptance of carbon dioxide storage depends in part on a thorough characterization and assessment of the underlying geology, including the ability of target reservoir zones to receive and store $CO_2$ without impact to the groundwater resources. AEP expected that, not only would the project development be more robust, but also the public would be more accepting of the ultimate design for the $CO_2$ injection and monitoring program if a geotechnical advisory group was formed from a wide ranging group of interested and knowledgeable stakeholders (i.e. experts) to broaden and bolster the resource expertise levels that were applied to the project, and include their input to the design philosophy and permitting strategy.

## 4.5 Other Miscellaneous

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on AEP related carbon storage projects that first started in 2003; select technical lessons learned from the Battelle meeting were compiled and are shown in an Appendix 6.1.

# 5. CONCLUSIONS

Notwithstanding AEP's decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project, as outlined in the cooperative agreement. Within Phase I, the cooperative agreement called for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement;
- Project specific developmental activities (i.e., front-end engineering and design);
- The initiation of the NEPA process; and
- The identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote $CO_2$ storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

The work completed in Phase I continues to support positive advancement of the Alstom CAP technology toward commercial demonstration at the intended scale. The work completed also provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs for planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere in the US and the lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

# 6. APPENDICES

## 6.1 Compilation of Miscellaneous Technical Lessons Learned for $CO_2$ Storage

(Note: Some of the items discussed below have their origins in previous work done by AEP outside the scope of this project. AEP used the knowledge gained in earlier work to further enhance the value of this commercial-scale project and build upon those earlier foundations. It is AEP's contention that sharing such information in this document is of great benefit to future project efforts AND, THUS, WHY THEY HAVE BEEN INCLUDED.)

### Well Design:

- Larger diameter tubing in injector wells aided in $CO_2$ deliverability to the reservoir. Also, larger diameter injection tubing should help to avoid plugging issues and allow a more diverse suite of wire line tools to be run.
- The annular system may need to be reworked so as to avoid future mineral precipitation in the injection tubing string. This may include:
    - Detection and prevention of tubing damage during installation
    - Sensitive annulus pressure or fluid level detectors for sensing minute leaks of annular fluid out of the annular space
    - Use of annular fluid that is less likely to precipitate minerals in a dry ($CO_2$) environment (e.g. KCl weighted fluid is more expensive but has lower potential for mineralization than CaCl)
    - Periodic injections of water, or some fluid, for removal/dissolution of minerals from injection tubing
    - Use of scale inhibitors in injection tubing
    - Use of tubing material that inhibits coalescence of precipitates
    - Use of larger diameter injection tubing (i.e. tubing with larger minimum ID restriction)
- Real-time down hole temperature and pressure gauges are difficult to work around; may look at "wireless" options in the future
- May want to look at a horizontal injection well option in lower permeability formations (e.g. Rose Run)
- May look at multi-completion monitoring wells for monitoring in separate reservoirs – instead of having one monitoring well per reservoir
- The small diameter of AEP-1 was an issue, particularly since this well was used as an injection well. In this case, this was due to the fact that this well was not originally designed to be an injection well, but rather a characterization well. Nevertheless, avoid small diameter wells in the future.
- Stainless steel casing requires special running equipment, including high torque power tongs and special dies.

### Permitting:

- Class VI regulations require a separate UIC permit application for each injection well (no area permits). In addition, five (5) companion plans must be prepared and submitted with the permit application, including: Area of Review and Corrective Action Plan; Testing and Monitoring Plan;

Emergency and Remedial Response Plan; Well Plugging Plan; Post Injection Site Care and Site Closure Plan.

- Financial assurance requirements under Class VI regulations require payment up front to cover 50 years of post injection monitoring, corrective action, well plugging, and other items. This must be arranged by the time the UIC permit application is submitted.

## Drilling:

- Use Geotech/pilot hole to help guide conductor/surface casing design/placement
- When drilling in bedrock  plan on a larger diameter conductor hole
- Have spare parts, pumps and air compressors on hand

## Well Logging - Collection:

- Ensure baseline PNC logs are run after sufficient amount of time has passed from drilling the well
- Can run fewer “high-end/expensive” open hole logs in well-established areas

## Well Logging – Analysis:

- Better data management from start of project – faster data integration

## Well Coring – Data Analysis:

- Collect more whole core samples from injection zones
- Perform more SCAL tests to be used for model input parameters (e.g. mercury injection, geomechanical)

## Injection Testing – Data Collection:

- High Priority, especially for “first” well in project/region
- Allow sufficient time for multi-zone (i.e. with packers) injection testing
- Equipment Planning – Thoroughly Vet Vendors (experience, novelty of what we planned)
- Procurement of high quality open hole packers for zone isolation
    - Should have multiple back-ups on-site
    - Should be field-serviceable
- Real-time down hole gauges for injection testing should be robust and field-serviceable
- Design well injection system to allow shutdown and shut-in (for reservoir characterization)
- Final key in characterization logging → core → reservoir test
- Thoroughly/accurately plan/schedule/budget, including contingencies (plan for failures, be flexible, nimble)
- Online/live data analysis during testing is strongly desired
- The flow meter logging surveys were very successful in identifying candidate in-flow zones for subsequent detailed hydrologic (packer) tests. In addition, collection of a temperature log 24 hours after the final dynamic logging survey provided valuable information to corroborate the results of the flow meter logging surveys. Strongly recommend incorporating flow meter logging surveys in all future well characterization programs in addition to standard coring and well logging programs.
- The discrete depth interval hydrologic (packer) tests were very successful in quantifying critical reservoir hydrologic parameters needed to identify candidate $CO_2$ injection zones and assess (model) $CO_2$ injectivity. Strongly recommend incorporating hydrologic (reservoir) testing in all future well characterization programs in addition to standard coring and well logging programs.

- It was prudent to allow time between the Phase I reservoir testing (flow meter logging) and Phase II reservoir testing (packer tests conducted within individual discrete-depth interval zones) to allow time to select target zones for detailed testing.
- Conducting both injection and withdrawal slug/DST tests is important.
- A service rig with a swabbing unit is essential for supporting the reservoir testing work. A drill rig is not required, and would not have the ability to conduct swabbing.
- Packer bypass (cross formational flow) was observed during some of the constant rate injection tests. Although injection pressures were well below fracture pressure, it is recommended to use low injection pressures in future injection testing.
- It is important to have a portable pump on site that can be used to inflate the packers and load the tubing string for injection slug/DST tests. This way, the pump truck only needs to be called to the site for the longer-duration constant rate injection tests. We used a rental pump for this purpose, and it turned out to be a cost saver.

## Injection Testing – Data Analysis:

- Should allocate more staff time for analysis of injection testing data
- Software proved to very useful for analyzing reservoir pressure data for the purpose of characterizing reservoir properties.
- It is important to regularly analyze reservoir pressure data (injection/fall-off events) from the injection wells and monitoring wells. This was easy for the injection wells because bottom hole pressure data was obtained in real time; whereas, data from the monitoring wells was available only when gauges were pulled.
- Injectivity index is a useful parameter for tracking overall injection performance.
- Use of pressure memory gauges in the monitoring wells was appropriate and cost effective vs. real-time pressure monitoring systems for the short duration of this project. For longer-duration injection projects, real-time pressure monitoring systems may be more cost effective.

## History Matching – Pressure Data:

- Develop workflow/process for interpreting and integrating results of $CO_2$ injection data
- Could have used lower pressure data sampling rate in monitoring wells and, to a degree, the injection wells
- More data accessibility in the future –continually self-updating data stream instead of weekly spreadsheet updates
- Good effort so far, need to do more, especially in correlation of pressure front and $CO_2$ front
- Pressure monitoring is very promising, but more modeling/analysis is needed [but geophysical methods may be at same state of development]

## Geophysics:

- Need 3D data (could drive land acquisition), identifies faulting SE, guides risk
- Acknowledge limitations on purchased data (→can drive need for acquisition)
- Include detailed geomechanics
- Modeling effort (guides injection pressure) can minimize need for seismic
- Integrate seismic data is static model
- PNC – useful, low cost (allow time post drilling)
- Consider operation issues in planning repeats
- Fluid sampling shallow groundwater

- Soil Gas – likely needed, will be very labor intensive
- Groundwater monitoring – key to involve local plant expertise

## Others:

- Use ongoing monitoring to guide future monitor needs (5yr→30yr) {adaptive strategy}
- Brine – target is to determine $CO_2$ breakthrough
- Satellite surface upheaval monitoring could be valuable

# Appendix D

## AEP Comments on the 2012 Proposed GHG NSPS for New Sources

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**Original by Mail**
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June 25, 2012

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code #2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

ATTN: Docket ID No. EPA-HQ-OAR-2011-0660

Re: *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*
Docket ID No. EPA-HQ-OAR-2011-0660

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed standard of performance (NSPS) for greenhouse gas (GHG) emissions from electric generating units (EGUs) under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's

Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), and incorporates by reference the comments submitted by these groups.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

John M. McManus

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| | | |
|---|---|---|
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Outline of AEP Comments:

I. AEP Is an Industry Leader on GHG Emission Reductions and Climate Change Policy

II. EPA's Combination of Two Existing Section 111 Source Categories Into a New NSPS Source Category For One Pollutant Is an Arbitrary and Capricious Departure From Prior Agency Practice

   A. EPA has not complied with the requirements for publishing categories of stationary sources under Section 111 of the Clean Air Act

   B. EPA has not demonstrated that NGCC is the best system of emission reduction for the proposed category
      i. NGCC is not a "system of emissions reduction"
      ii. EPA's justifications for selecting NGCC as the "best system of emission reduction" are not supported by logic or the facts

   C. EPA's proposed Subpart TTTT raises adverse policy concerns
      i. EPA's proposal would trigger PSD program obligations
      ii. EPA's proposal would eliminate new coal-fired generation

III. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

   A. The proposed NSPS does not apply to modified or reconstructed sources

   B. The proposed NSPS is not a BACT floor

IV. EPA's Proposed Rule Is Based On Faulty Data

   A. Cost analysis

   B. Selection of 1,000 lb $CO_2$/MWh emission rate

   C. IPM modeling

   D. Levelized cost analysis

   E. Benefit analysis

V. Carbon Capture and Storage Is Not Commercially Available For Coal-Based Generation and Will Not Become a Viable Control Option Until Significant Challenges Are Addressed

A. Technically feasible is not the same as commercially available

B. Significant technical, financial, regulatory, and legal barriers exist that must be addressed before CCS is commercially acceptable for coal-based generation

C. Numerous public and private organizations have concluded that CCS for coal-based generation is not commercially available and that significant development barriers remain

D. AEP's experience demonstrated both the potential of CCS and the significant challenges that still must be addressed

E. EPA's rationale is insufficient for concluding that CCS is a feasible control technology option for coal-based generating units

i. First EPA basis: The "Technical Feasibility of CCS"
ii. Second EPA basis: "Expected reduction in CCS costs"
iii. Third EPA basis: "Limited amount of construction of new coal-fired power plants"
iv. Fourth EPA basis: "State Requirements for CCS"

VI. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

A. The proposed NSPS does not apply to modified or reconstructed sources

B. The proposed NSPS is not a BACT floor

VII. Response to Technical Questions for Which EPA Solicited Comments

A. Use of gross-based output limits

B. Adequacy of the proposed 1,000 lb $CO_2$/MWh NSPS

C. CCS as the Best System of Emission Reductions

D. Coal refuse

E. Combined heat and power

F. Stationary simple cycle turbines

VIII. Conclusion

A. Fuel-specific standards should be established in lieu of a one-size-fits-all approach that effectively requires one fuel (coal), but not another (natural gas) to use an undeveloped control technology

B. EPA should not base a standard on technology that is not commercially available, but if EPA insists on promulgating a standard based on projected future technology developments, the long-term average limit should be revised to align with a more realistic CCS development timeline

C. EPA should either withdraw its proposed rule or convert it to an advance notice of proposed rulemaking, and continue gathering information

Appendix A: Assessments of the State of CCS Development for Coal-Based Electric Generation

## I. AEP Is an Industry Leader On GHG Emission Reductions and Climate Change Policy

AEP has a long history of proactive involvement in stewardship activities. Beginning in the 1940's, AEP was involved in re-forestation programs, including specific efforts at portions of its large land holdings to return acreage that had been devoted to agricultural and mining activities to potential carbon sinks. In 1995, AEP committed to plant over 15 million trees in one five-year period as part of its participation in the U. S. Department of Energy's Climate Challenge Project. AEP has also pioneered international and domestic efforts to preserve existing forested lands, increase the number of actively managed forested acres in state and federal preserves and wildlife areas, and to create newly forested areas where the sequestration potential of good forest management projects could be studied to help develop the tools to quantify creditable increases in the sequestration of $CO_2$.

In 2003, AEP became a founding member of the Chicago Climate Exchange (CCX), the first voluntary GHG credit trading system in the U. S. AEP established and met goals to reduce or offset GHG emissions by an annual target of 6% (compared to emission levels during 1998-2001) by 2010. AEP has voluntarily established a further goal of reducing or offsetting our GHG emissions by 10% (compared to 2010 levels) by 2020.

AEP has participated in EPA's Climate Leaders Program, earning recognition and awards for innovation and achievement. In 2006, the Carbon Disclosure Project named AEP to its Climate Leadership Index, placing AEP among 50 other international corporations whose strategic awareness of the risks and opportunities associated with carbon constraints, and effective programs to reduce overall GHG emissions, have earned similar distinctions.

Since 2002, AEP has worked diligently to refine large scale sodium sulfur battery technology, and was the first utility to install and demonstrate this advanced energy storage technology as a means to bridge the gap between intermittent renewable resources, such as wind and solar power, and the constant need for on-demand electric service. Sodium sulfur storage batteries are now being integrated into the "smart grid" to improve transmission reliability and provide emergency power.

AEP's leadership and innovation in our core generation, transmission and distribution services has led to improvements in the efficiency of the delivery of our product through continual advances in generation technology efficiency, lowering transmission line losses, energy audits, support for improvements in the efficiency of end-use appliances and fixtures, and improved delivery of real-time pricing and usage information through the electric grid. AEP Ohio recently announced that its business customer energy efficiency programs in Ohio have resulted in over 600 million kilowatt-hours of energy savings, enough power to serve 56,000 homes for one year.

AEP has also played a major role in supporting Congressional action to establish comprehensive climate change legislation that can use the power of markets to capture additional reductions in GHG emissions. AEP supported efforts in 2009 to design common-sense climate change legislation that would allow the United States to achieve significant progress in reducing GHG emissions without sacrificing the opportunity for the U.S. to remain economically secure and to retain domestic jobs.

Throughout over a century of operations, AEP has been a pioneer in the development of advanced coal generation technologies, which include many first-in-the-world accomplishments that have set the standard for combustion efficiencies, emissions control, and system performance. A few examples include the first reheat generating coal unit (1924); the first heat rate below 10,000 Btu/kWh at a coal plant (1950); the first natural-draft, hyperbolic cooling tower in the Western Hemisphere (1963); the first combined-cycle operation of a pressurized, fluidized bed combustion plant in the United States (1990); and the first venting of flue gas through a natural-draft cooling tower in the United States (2012).

While AEP's generation portfolio has shifted over the last decade to include more natural gas-fired generation, this year we will complete construction of the country's first ultra-supercritical coal-fired generating unit, the John W. Turk, Jr. Power Plant in Hempstead County, Arkansas. The Turk Plant has thermal efficiency comparable to the current generation of integrated gasification combined cycle (IGCC) units and is better suited to low-sulfur western coals than many common designs of IGCC technology.

Perhaps AEP's most significant contribution in the area of greenhouse gas emission was the completion of a validation scale demonstration of the world's first fully integrated carbon capture and storage project at an existing coal-fired electric generating unit. The Mountaineer Carbon Capture and Storage Project treated a 20-MW slip stream of flue gas from AEP's 1300 MW Mountaineer Plant, removed more than 90 percent of the $CO_2$, and compressed and permanently sequestered the captured $CO_2$ into two deep underground formations more than

7,000 feet below the surface of the plant property. The project successfully operated from 2009 to 2011, captured and stored over 37,000 tons of $CO_2$, and continues post-closure monitoring under the first $CO_2$-oriented underground injection control permit issued by the State of West Virginia. A second phase of that project, which would have advanced the technology to a 235-MW commercial scale, was deferred due to the reluctance of our state regulators to impose the significant cost of further technology development on our ratepayers.

Notwithstanding AEP's lengthy history of environmental conservation and support for federal greenhouse gas reduction efforts, AEP cannot support EPA's proposed GHG NSPS for EGUs. As outlined below, EPA's proposed rule is unlawful, is based on faulty information, and would hinder the very efforts to develop clean coal technology that Congress, EPA, and AEP have worked so long and hard to advance. AEP is particularly concerned that the proposed rule will "freeze" carbon capture and storage (CCS) technology development at its current pre-commercial state and hinder the kind of progress that would allow coal to continue to play a vital role in America's energy policy. A detailed report of the current state of CCS technology is included in these comments, which supports EPA's conclusion that no finding can be made that CCS is an available and affordable control technology, and therefore no standard can be established that would require CCS for compliance for coal-fired utility units. For the reasons explained below, EPA should withdraw the proposed rule, or limit its scope to combined cycle natural-gas fired EGUs.

## II. EPA's Combination of Two Existing Section 111 Source Categories Into a New NSPS Source Category For One Pollutant Is an Arbitrary and Capricious Departure From Prior Agency Practice

Different electric generation technologies have always had different § 111 standards that could be met in a practical way. Indeed, where appropriate, EPA has subcategorized based on slightly different technologies and fuels within the steam electric generating unit category to accurately establish standards that can be achieved through application of the "best demonstrated" technologies at a reasonable cost. EPA's proposal, however, dramatically departs from this past practice and sets a dangerous new precedent. Congress authorized EPA to establish new categories of stationary sources only upon making a finding that emissions from that category endanger public health or welfare, and to prescribe standards of performance that reflect the best system of emission reduction applicable to such sources, taking into account the cost of achieving such reduction, any non-air quality and environmental impacts, and energy requirements. Congress did not empower EPA to engage in centralized economic planning or to command particular means of production and prohibit others. EPA makes no express endangerment finding for its proposed new Subpart TTTT, and fails to demonstrate, as it has carefully done in each prior NSPS, that the standards proposed for each regulated pollutant can be achieved by every source subject to the standard on a cost-effective basis.[1]

Congress never intended or authorized the actions that EPA proposes to take in Subpart TTTT, nor has EPA ever previously developed a similar standard. Indeed, in every prior rulemaking where EPA forecasted that currently prevailing market conditions made the construction of new gas- or oil-fired capacity unlikely, EPA decided not to undertake a detailed analysis of the existing standards or any more stringent standards that might be achieved at such units, and concluded there was no reason to modify the existing standards.[2] Yet here, while concluding that no new coal-fired capacity is likely to be built within the next eight years, EPA has proposed a standard that has not been demonstrated at any coal-fired unit, and that EPA itself

[1] See e.g., 62 Fed. Reg. 36,948, 36,952 (July 9, 1997) (EPA can consider establishing a standard based on the cleanest fuel so long as there is a technology which allows other fuels to comply with that limit while providing cost-effective emission reductions).

[2] See e.g., 43 Fed. Reg. 42,154, 42,171 (Sept. 19, 1978) ("EPA did not conduct a detailed study of combustion modification or $NO_x$ flue gas treatment for oil- or gas-fired boilers because few, if any . . . are expected to be built in the future.").

admits cannot currently be achieved on a cost-effective basis or without significant energy penalties.[3]

The Clean Air Act is replete with provisions applicable specifically to coal-fired electric generating units, including provisions applicable to new and expanded coal-fired generating capacity. In 1970, 1974, 1977, and 1990, Congress fine-tuned the Clean Air Act to carefully balance the nation's social and economic needs for adequate, reliable, and affordable coal-fired electricity generation with appropriate mitigation of the air quality impacts of such generation. In the past decade, Congress has passed multiple bills designed to advance clean coal technology, thereby cementing coal-fired generation as an important aspect of America's "all-of-the-above" energy policy. Yet, EPA's proposed Subpart TTTT NSPS for GHG emissions from EGUs would impose insurmountable obstacles to new coal-fired generating units as of April 13, 2012, a policy that is nowhere contemplated within the existing Clean Air Act.

Moreover, EPA's protestations notwithstanding, EPA's proposed rule would have severe adverse consequences. Further advancements in coal-fired generation would be suspended, if not totally precluded, by the proposal EPA has issued for GHGs. And, EPA's proposal would do nothing to incentivize further development of CCS technology. Tot he contrary, EPA's proposal would quite likely "freeze" the current state of technology development by discouraging further investment in coal assets. This would be a disastrous outcome for future energy and economic security of the United States.

None of these adverse consequences is necessary. According to EPA, the proposed GHG NSPS for EGUs provides no benefits, because it would simply push potential owners and operators of electric generating units to choose a technology, NGCC, which they are already planning to build in the near-term, due to the current low price for natural gas. And, EPA has acknowledged that it lacks sufficient information to promulgate performance standards for several kinds of sources within its proposed new category, including new sources outside the continental United States and modified and reconstructed sources. EPA should withdraw its proposed rule, or redesignate it as an advanced notice of proposed rulemaking, and proceed with GHG NSPS for EGUs only when EPA has sufficient information to regulate those emissions as the Clean Air Act intended.

[3] 77 Fed. Reg. 22,414-415 (April 13, 2012).

### A. EPA has not complied with the requirements for publishing categories of stationary sources under Section 111 of the Clean Air Act

Clean Air Act § 111(b)(1)(A) required EPA's Administrator to publish, no later than March 31, 1971, a list of categories of stationary sources that, in the Administrator's judgment, "cause[ ] or contribute[ ] significantly to[ ] air pollution which may reasonably be anticipated to endanger public health or welfare."[4] The Act authorizes EPA's Administrator to "revise" this list of categories "from time to time thereafter."[5] "That provision obviously contemplates an evaluation by the Administrator of the risk that certain types of air pollution will 'endanger' public health and welfare, and the risk that allowing construction of new stationary sources, even subject to existing state and local regulation, will contribute 'significantly' to that air pollution."[6] Following the inclusion of a category of stationary sources on EPA's "cause-or-contribute-significantly" list, the Act directs EPA's Administrator to "publish proposed regulations"; "afford interested persons an opportunity for written comment on such proposed regulations"; "promulgate . . . such standards with such modifications as [the Administrator] deems appropriate"; and then "review and, if appropriate, revise such standards" at least every 8 years.[7]

In this rulemaking, EPA is not following the process outlined in Clean Air Act § 111(b)(1). EPA is not adding a category of new stationary sources to its "cause-or-contribute-significantly" list, or revising existing NSPS to add standards for greenhouse gas emissions. Instead, EPA is proposing to revise the list of categories to add a new category of stationary sources that are already on the list. As EPA acknowledges, the stationary sources that are affected by EPA's new proposed NSPS – "electric utility steam generating units . . . and combined cycle units that generate electricity for sale and meet certain size criteria" – are already included in 40 C.F.R. Part 60, Subparts Da and KKKK.[8] Moreover, EPA is not proposing Subpart TTTT because it made a new "cause-or-contribute-significantly" finding for that category. "EPA has already [separately] determined that both those source categories cause or contribute significantly to air pollution that may reasonably be expected to endanger public health or welfare."[9] It follows that EPA is proposing a new category of "fossil fuel-fired electric

[4] 42 U.S.C. § 7411(b)(1)(A).
[5] Id.
[6] Nat'l Asphalt Pavement Ass'n v. Train, 539 F.2d 775, 783 (D.C. Cir. 1976) (footnote omitted).
[7] 42 U.S.C. § 7411(b)(1)(B).
[8] 77 Fed. Reg. at 22,394.
[9] Id. at 22,397.

utility generating units" for purposes other than those contemplated by the Clean Air Act – namely, to ensure that prospective owners and operators of covered electric utility generating units construct natural gas combined cycle (NGCC) units.[10] Because EPA is "rel[ying] on factors which Congress has not intended it to consider," EPA's adoption of a final rule creating a combined, $CO_2$-specific category of "fossil fuel-fired electric utility generating units" would be arbitrary and capricious.[11]

As EPA recognizes, "combining the Da category and a portion of the KKKK category, and applying as the standard of performance the rate that natural gas-fired EGUs can meet, represents a departure from prior agency practice."[12] EPA acknowledges in the preamble to its proposal that "[b]efore today's rulemaking, the EPA listed different types of fossil fuel-fired EGU's as source categories."[13] EPA has regulated stationary gas turbines under Subpart GG since 1979, and has regulated combined cycle steam/electric generating systems under Subpart KKKK since 2006.[14] It is also a departure from agency practice to have two NSPS categories regulating different air emissions (*i.e.*, criteria pollutants vs. carbon dioxide) from the same stationary source (*e.g.*, a coal-fired electric generating unit). Without a justification for deviating from its past decisions to treat electric utility steam generating units and stationary gas turbines/combined cycle systems as separate categories, and to regulate each kind of stationary source under a single NSPS subpart, EPA's creation of Subpart TTTT cannot pass muster under the requirements of section 307(d) of the Clean Air Act or the analogue provisions of the Administrative Procedure Act.[15]

EPA offers two primary reasons for combining coal-fired boilers from Subpart Da and combined cycle systems from Subpart KKKK for purposes of regulating GHGs.[16] EPA's first stated reason is that it is "reasonable" for "all new fossil fuel-fired electricity generating units that meet specified minimum criteria," and "serve baseload or intermediate demand," to be

[10] Id. at 22,392
[11] Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43, 103 S. Ct. 2856 (1983).
[12] 77 Fed. Reg. at 22,418.
[13] Id. at 22.397.
[14] E.g., 70 Fed. Reg. 8,314, 8,316 (Feb. 18, 2005); 77 Fed. Reg. at 22,397.
[15] See, e.g., F.C.C. v. Fox Television Stations, 556 U.S. 502, 515, 129 S. Ct. 1800 (2009) (holding that an agency changing its policies must "provide reasoned explanation for its action," i.e., "that there are good reasons for the new policy.").
[16] 77 Fed. Reg. at 22,410.

"subject to the same requirements...because they serve the same function[.]"[17] There are several problems with EPA's focus on serving baseload or intermediate demand as a defining characteristic of the stationary sources in the proposed new Subpart TTTT. First, there are no clear, widely accepted definitions of "baseload" or "intermediate" demand. Second, the duty cycle (peaking, cycling, baseload, etc.) of any given electric generating unit may change over time, based on economic, physical, and legal factors. Third, EPA's description of proposed Subpart TTTT is not accurate, as EPA acknowledges that "new sources in non-continental areas" and simple cycle turbines would not be covered by Subpart TTTT, regardless of whether they serve baseload or intermediate demand.[18] EPA also fails to explain the selection of only NGCC and coal-, petcoke-, and oil-fired sources in Subpart TTTT. There are several other kinds of generators in the United States that serve baseload or intermediate demand, including simple cycle gas turbines and biomass-fired generators. EPA included none of them in proposed Subpart TTTT. Fourth, EPA's argument begs the question: **why** is it "sensible to treat as part of the same category units that generate baseload or intermediate load electricity, regardless of their design or fossil fuel type"?[19] Why does the fact that sources from those two categories serve baseload or intermediate load justify combining those sources into a single category for purposes of GHG emissions? EPA does not say.

Instead, EPA answers the opposite question, *i.e.*, why was it **not** sensible to treat as part of the same category units that generate baseload or intermediate load electricity for purposes of regulating **criteria** pollutant emissions? EPA asserts that it was not appropriate to combine Subpart Da and combined cycle units for criteria pollutants because the "array of control options for criteria and air toxic air pollutants" available to coal-fired EGUs "generally do not reduce their criteria and air toxic emissions to the level of conventional emissions from natural gas-fired EGUs."[20] However, coal-fired EGUs also do not have cost-effective, commercially available control options that lower their greenhouse gas emissions to the level of emissions from natural gas-fired EGUs. According to EPA, the most efficient supercritical and ultra-supercritical coal-fired boilers "have $CO_2$ emissions of approximately 1,800 lb/MWh and provide the lowest

[17] Id. at 22,398.
[18] Id.
[19] Id. at 22,410.
[20] Id. at 22,411.

overall costs for conventional coal-based electricity."[21] While CCS might some day be able to lower the emissions from those boilers to match the emissions from NGCC without CCS, EPA acknowledges the Department of Energy's National Energy Technology Laboratory's estimates that "today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal (PC) plant."[22] EPA also endorses the findings of the Interagency Task Force on Carbon Capture and Storage established by President Obama (and co-chaired by EPA) that barriers to cost-effective deployment of CCS technology will take years to overcome.[23] While CCS is "technically viable," "full-scale carbon separation and capture systems have not yet been installed and fully integrated at an EGU."[24] Thus, the "array of control options" for coal-fired boilers cannot reduce their $CO_2$ emissions to the level of emissions from natural gas-fired EGUs that do not have add-on controls. EPA's justification for treating $CO_2$ emissions from Subpart Da and combined cycle units differently from criteria pollutants from those sources is not supported by the facts.

EPA's second stated reason for combining Subpart Da and combined cycle systems from Subpart KKKK for purposes of regulating GHGs is that "all newly constructed sources have options in selecting their design," and thus "prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit."[25] Again, this purported justification suffers from several faults. First, this assertion does not explain EPA's decision to create a new category that combines NGCC's from Subpart KKKK with coal-fired boilers from Subpart Da, rather than crafting separate greenhouse gas emission standards for both subparts. Second, EPA's assertion fails to consider the locational impacts of this rule. Power generation decisions are often localized in nature, due to the need to have physical infrastructure to supply fuel and export electricity. For example, the economics of building a coal plant are much different in the middle of a large coal basin with no nearby gas infrastructure, such as the Powder River Basin, than they are in the middle of a gas-producing region with no nearby coal basins. Similarly, there are areas in which CCS cannot be located, such as areas that are seismically active. EPA has already recognized the impact of variability in

[21] Id. at 22,417.
[22] Id. at 22,415.
[23] Id. at 22,414.
[24] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, at 26 (Oct. 2010), available at http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
[25] Id. at 22,410.

fuel supply by excluding Hawaii and U.S. territories from its proposed rule. Setting a national $CO_2$ performance standard without considering locational impacts is not a prudent approach. Third, the argument also overlooks the unprecedented nature of what EPA is suggesting. In the past, owners and operators may have needed to modify the design of a proposed new source to comply with a New Source Performance Standard. Under Subpart TTTT, in comparison, EPA is encouraging owners and operators to build a different kind of source entirely or to employ a control technology that is not commercially available. Section 111 does not empower EPA to manipulate fuel markets, or to pick winners and losers among alternative electric generation technologies. To the contrary – Section 111(b)(5) clearly forbids EPA from dictating that prospective owners and operators must choose a particular technological design in order to comply with a standard of performance (with the exception of work practices or operational standards under Section 111(h), which is not relevant to EPA's proposal).

Picking winners and losers is, transparently, EPA's true purpose here. EPA is not proposing to combine coal-fired boilers from Subpart Da and NGCC's from Subpart KKKK because they serve the same kind of load, because prospective owners and operators of new sources "have options in selecting their design," or because "[c]ombining the categories does not raise adverse policy concerns."[26] EPA is proposing to put NGCC's into a category with Subpart Da stationary sources because it wants to conclude that NGCC's are the "best system of emission reduction" (BSER) for that category.[27] In other words, EPA wants to be able to promulgate a $CO_2$ NSPS for fossil-fuel-fired electric utility generating units that is based on the $CO_2$ emissions of an NGCC. EPA admits this when it says that "retaining (and establishing separate standards for) separate source categories...would create the risk of significantly higher GHG emissions and other air pollutants from some new units[.]"[28] Regulating $CO_2$ emissions from utility boilers under Subpart Da, and $CO_2$ emissions from NGCC's under Subpart KKKK, would require performing separate BSER analyses for each category, which would result in EPA setting a higher $CO_2$ standard for utility boilers. In short, EPA decided to create a new, duplicative, combination source category in order to ensure that EPA's BSER analysis would reach the agency's desired and pre-determined result – the effective elimination of coal as an option for future electric generation projects – without regard to statutory instructions.

[26] Id. at 22,411.
[27] 42 U.S.C. § 7411(a)(1).
[28] 77 Fed. Reg. at 22,411.

"[S]ection 111 of the CAA...give[s] the EPA substantial discretion to create categories of sources for which standards must be promulgated."[29] That discretion, however, is not unlimited. Agencies must engage in "reasoned decision making."[30] "Reasoned decision making requires an agency to 'examine the relevant data and articulate a satisfactory explanation for its action[s].'"[31] EPA has provided no such explanation. To the contrary – EPA's explanations for its proposed rule are so "implausible that [they] could not be ascribed to a difference in view or the product of agency expertise."[32] Combining sources from two different source categories into a single source category for purposes of regulating greenhouse gas emissions, while maintaining the original separate source categories for purposes of regulating criteria pollutants from the same sources, would be arbitrary and capricious, because it would "rel[y] on factors which Congress has not intended [EPA] to consider" and "run[ ] counter to the evidence before the agency[.]"[33] Consequently, EPA should reverse its decision to combine electric utility steam generating units and combined cycle units into a single source category.

**B. EPA has not demonstrated that NGCC is the best system of emission reduction for the proposed category**

EPA's proposed Subpart TTTT is also fatally flawed because its proposed selection of natural gas combined cycle (NGCC) systems as the "best system of emissions reduction" does not meet the requirements of Section 111 of the Clean Air Act.

**i. NGCC is not a "system of emissions reduction"**

Under § 111(a)(1), a standard of performance must "reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[34] As EPA explained in another rulemaking earlier this year:

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[29] Davis Cty. Solid Waste Mgmt. v. E.P.A., 101 F.3d 1395, 1405 (D.C. Cir. 1996) (citations omitted).
[30] Judulang v. Holder, 132 S.Ct. 476, 484, 181 L.Ed.2d 449 (2011).
[31] Portland Cement Ass'n v. E.P.A., 665 F.3d 177, 187 (D.C. Cir. 2011).
[32] Motor Veh. Mfrs. Ass'n, 463 U.S. at 43.
[33] Id. See also Judulang at 484 (holding that judicial review of an agency action requires a determination of, among other factors, "whether the decision was based on a consideration of the relevant factors").
[34] 42 U.S.C. § 7411(a)(1).

> The level of control prescribed by CAA section 111 historically has been referred to as ''Best Demonstrated Technology'' or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER.[35]

Outside this rulemaking – indeed, in a guidance document currently posted on the section of EPA's website that discusses this rulemaking – EPA has consistently referred to the "best system of emission reduction" as a system of emissions control:

> In determining BDT, EPA typically conducts a technology review that identifies what **emission reduction systems** exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation. The resultant standard is commonly a numerical emissions limit, expressed as a performance level (i.e. a rate-based standard). While such standards are based on the effectiveness of **one or more specific technological systems of emissions control**, unless certain conditions are met, EPA may not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.[36]

EPA has used much the same language to describe the process by which it determines "best system of emission reduction" or "best demonstrated technology" in multiple rulemaking notices.[37]

This is also consistent with how Congress described its intent in creating the New Source Performance Standards. The official summary of the Conference Agreement on the Clean Air Amendments of 1970 stated that "new stationary sources . . . must be controlled to the maximum practicable degree[,]" and "[s]tandards of performance must be set at the greatest degree of control attainable through the application of the best system of emission reduction which has

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[35] 77 Fed. Reg. 9304, 9423 (Feb. 16, 2012).

[36] EPA, Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act, www.epa.gov/carbonpollutionstandard/pdfs/111background.pdf (emphasis added).

[37] See, e.g., 76 Fed. Reg. 65,653, 65,655 (Oct. 24, 2011); 73 Fed. Reg. 44,354, 44,486-87 (July 30, 2008); see also 70 Fed. Reg. 62,216 (Oct. 28, 2005) (stating, "As with any NSPS analysis, EPA evaluated the controls that effect the best emission reduction of the pollutant in question"); see also, e.g., 44 Fed. Reg. 52,792, 52,797 (Sept. 10, 1979) (concluding, in the final rulemaking for NSPS Subpart GG, that "water injection is considered the best system of emission control for reducing NOx emissions from stationary gas turbines").

been adequately demonstrated[.]"[38]

Here, EPA did not follow its stated practice for determining "best system of emission reduction," as described in its guidance documents and rulemaking notices. Rather than examining available emission reduction systems, EPA states that it "considered a range of natural gas-fired and coal-fired **generation technologies**, with available controls."[39] This is not only inconsistent with EPA's description of its usual practices, it is inconsistent with the explicit text of the statute. An NGCC is not a "system of emission reduction." NGCC is a fuel-specific (i.e., natural gas fuel) generation technology. An NGCC is also a "stationary source," as defined in 42 U.S.C. § 7411(a).[40] In effect, EPA has reached the nonsensical conclusion that the "best system of emission reduction" for a coal-fired steam electric generator is building a different kind of source altogether – a gas-fired combined cycle combustion turbine.[41]

Sec. 111(b)(5) of the Clean Air Act generally prohibits the Administrator from requiring any new source "to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[42] EPA has effectively admitted that it crafted the proposed Subpart TTTT for the purpose of compelling potential owners or operators of electric utility generating units to construct NGCC units. At the very least, it has chosen as a "best system of emission reduction" a stationary source that is not a "system of emission reduction." Because an agency may not promulgate a rule that is outside "the scope of the authority delegated to the agency by the statute," EPA's proposed selection of NGCC as the "best system of emission reduction" for its proposed Subpart TTTT would be unlawful.[43]

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[38] ___ Cong. Rec. S. 20601 (Dec. 18, 1970) (Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970).
[39] 77 Fed. Reg. at 22,417 (emphasis added).
[40] See, e.g., 71 Fed. Reg. 38,482, 38,483 (July 16, 2006) (finalizing the NSPS for stationary combustion turbines, which include NGCC's); see also proposed 40 C.F.R. § 60.5580 (defining "electric utility steam generating unit" to include "stationary combustion turbine[s]," which is in turn defined to include "combined cycle combustion turbines").
[41] See 77 Fed. Reg. at 22,410 (stating that the fact that "prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit" justifies the combination of sources from Subparts Da and KKKK).
[42] 42 U.S.C. § 7411(b)(5).
[43] Motor Veh. Mfrs. Ass'n, 463 U.S. at 42.

### ii. EPA's justifications for selecting NGCC as the "best system of emission reduction" are not supported by logic or the facts

EPA's selection of NGCC as BSER also is not supported by its asserted justifications. EPA says that its selection of NGCC as the "best system of emission reduction" is warranted for two reasons: "the emissions benefits" and "the changed economic circumstances, notably the lowered prices of natural gas due to technological development and recent discoveries that have boosted recoverable reserves."[44] Neither reason is supported.

As to the "emissions benefits," EPA projects zero emissions benefits between now and 2030 from including coal-fired EGU's in the proposed Subpart TTTT source category. EPA says its "IPM model does not project construction of any new coal-fired EGUs during [the analysis period for this rulemaking,]" and that its "IPM modeling...projects that there will be no construction of new coal-fired generation without CCS by 2030."[45] EPA admits that "this proposed rule...will not have direct impacts on U.S. emissions of greenhouse gases under expected economic conditions."[46]

As to the "changed economic circumstances" of "lowered prices of natural gas," economic forecasting of future commodity prices is not a relevant consideration for setting performance standards under section 111(a)(1). Nor is speculation about the relative prices of natural gas and coal a decade or more from now.

EPA has "relied on facts which Congress has not intended it to consider" and "offered an explanation for its [proposed rule] that runs counter to the evidence before the agency."[47] EPA has not adequately demonstrated that the selection of NGCC as the best system of emissions reduction is justified, and consequently promulgation of proposed Subpart TTTT by EPA would be arbitrary and capricious.

[44] 77 Fed. Reg. at 22,418.
[45] Id. at 22,394 - 22,395.
[46] Id. at 22,401.
[47] Motor Veh. Mfrs. Ass'n, 463 U.S. at 43.

### C. EPA's proposed Subpart TTTT raises adverse policy concerns

Lastly, EPA asserts that combining sources in Subpart Da with NGCC systems from Subpart KKKK, and then selecting NGCC as the "best system of emission reduction" for the combined category, "does not raise adverse policy concerns."[48] AEP strongly disagrees.

#### i. EPA's proposal would trigger PSD program obligations

This rulemaking would, for the first time, make $CO_2$ a "regulated pollutant" for purposes of the Prevention of Significant Deterioration program. Under EPA's PSD regulations, "regulated NSR pollutant" is defined to include, among other things, "[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act" and "[a]ny pollutant that otherwise is subject to regulation under the Act as defined in paragraph (b)(49) of this section."[49] Through the Tailoring Rule, EPA revised the definition of "subject to regulation" to exclude greenhouse gases, including $CO_2$, for PSD purposes, except where new sources' and modifications' greenhouse gas emissions exceed certain thresholds.[50] EPA did not, however, exclude greenhouse gases from the definition of "pollutant...subject to any standard promulgated under section 111 of the Act." Consequently, if EPA promulgates the proposed Subpart TTTT, $CO_2$ will be a regulated NSR pollutant. EPA acknowledged this problem, but stated that comments in the preamble to EPA's Tailoring Rule made clear that EPA did not intend to trigger PSD for $CO_2$.[51] While this may be true, "language in the preamble of a regulation is not controlling over the language of the regulation itself[.]"[52] EPA also asserted that it had included a provision in its proposed rule that would "revise the NSPS regulations...to explicitly make clear that the NSPS trigger provision in the PSD regulations incorporate the Tailoring Rule thresholds."[53] The proposed revisions to 40 C.F.R. Part 60 listed at the back of the proposed rulemaking, however, include no such provision. Thus, the exact same dire consequences that EPA found to be "absurd" in the Tailoring Rule would be recreated by this rulemaking.

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[48] 77 Fed. Reg. at 22,411.
[49] 40 CFR 52.21(b)(50)(ii) and (iv).
[50] See generally 75 Fed. Reg. 31,514 (June 3, 2010).
[51] See 77 Fed. Reg. at 22,429.
[52] Wyoming Outdoor Council v. U.S. Forest Service, 165 F.3d 43, 53 (D.C. Cir. 1999), citing Jurgenson v. Fairfax Cty., Va., 745 F.2d 868, 885 (4th Cir. 1984).
[53] 77 Fed. Reg. at 22,429.

### ii. EPA's proposal would eliminate new coal-fired generation

EPA's proposal also has the practical effect of eliminating new coal-fired electric generation from State and national energy policy options. It does so by conditioning the construction of new coal-fired electric generating units on the use of technology that is not commercially available, and by the timing and magnitude of increased regulatory costs pinpointed uniquely on coal-fired generation. The proposal effectively forbids construction of new coal-fired generating units without CCS (or some presently unknown alternative technology for reducing power plant $CO_2$ emissions). CCS technology, if capable of reducing $CO_2$ emissions on a sustained basis, and if able to navigate the web of unresolved legal and policy issues associated with pore space ownership, long-term liability, and potential for migration across state boundaries within a single storage reservoir, has been estimated to add 80% to the cost of electricity from an ultra supercritical coal-fired generating unit equipped with state-of-the-art emission controls for conventional pollutants just for the capture operations, according to the Department of Energy (DOE)'s National Energy Technology Laboratory.[54] By comparison, EPA's proposed rule would add nothing to the cost of natural gas-fired NGCC technology.

EPA states that it "expects" that "funding for CCS through pilot or other demonstration programs" will continue and that the cost of CCS will decline.[55] That "expectation" is not grounded in facts. The Congressional Research Service recently reviewed DOE's CCS research programs, and found that since those programs began in 1997, and even with the infusion of significant additional funding in 2009 under the American Recovery and Reinvestment Act, "there are no commercial ventures in the United States that capture, transport, and inject industrial-scale quantities of $CO_2$ solely for the purpose of carbon sequestration."[56] The report concluded that "[t]he challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States."[57] Indeed, the report acknowledges that, based on comparative studies of the development of other environmental technologies, "the farther away a technology is from commercial reality, the more uncertain is its estimated cost.

[54] 77 Fed. Reg. at 22,415.
[55] Id. at 22,411.
[56] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700 (April 23, 2012).
[57] Id. at p.4.

At the beginning of the R&D process, initial cost estimates could be low, but could typically *increase* through the demonstration phase before decreasing after successful deployment and commercialization."[58] CRS concluded that DOE is just now initiating work on the first commercial-scale projects for CCS, and large-scale demonstration and deployment will not be ready until 2020.[59] Given that further *increases* in costs could occur during the large-scale development and deployment after 2020, and that half of the large-scale projects in the utility sector have been cancelled or substantially altered, EPA's expectation appears to be not much more than wishful thinking. A thorough discussion of the current state of CCS technology based on AEP's own experience is included in Part IV of these comments.

EPA may not set new source performance standards "solely on the basis of...'crystal ball inquiry.'"[60] It is bad policy to so needlessly and severely constrain the energy, economic, and security interests of the United States and the several States based on a snapshot of fuel prices as of April 13, 2012, and the fledgling efforts of an R&D program that has not yet produced a commercial-scale operation.

Subjecting new coal-fired electric generating units to a performance standard set for NGCC units, coupled with the cascade of other recent EPA rules that singularly increase the capital and operating cost of coal-fired generation (the MATS Rule, CSAPR, the GHG BACT rules, the proposed 316(b) rules, CCR management rules under the Resource Conservation and Recovery Act (RCRA), and the impending implementation and revision of the $SO_2$, $PM_{2.5}$, $NO_x$, and ozone NAAQS), effectively guarantees a decisive economic advantage to natural gas over coal as a fuel for new dispatchable generating capacity due not to markets, but rather to EPA rulemaking policies. Various studies and projections have concluded that this collection of EPA rules will accelerate the economic obsolescence of approximately 40-100 GW of existing coal-fired electric generating capacity (4,600 MW in AEP's eastern system alone between 2012 and 2017), or 15-30% of the nation's dispatchable coal-based generation resources. Much of that capacity will need to be replaced within the next few years, even without any growth in demand for electricity. Under EPA's proposal, NGCC will be the only option for replacing the coal-fired generating capacity made uneconomical by EPA's rules. The expected surge in demand for natural gas due to regulatory policy, at the same time regulatory policy eliminates coal as an

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58 Id. at p.6 (emphasis added).
59 Id. at p.23.
60 Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973) (citation omitted).

alternative to natural gas for new electric generating units, is bound to increase costs to electric consumers and raise the price of natural gas for consumers and companies outside the electricity sector. EPA's assumption that "the proposed rule will not impose costs by 2030" is not credible.[61]

The drastic disruption of competitive fossil fuel markets proposed by EPA also conflicts with Congressionally-enacted national energy policies and impairs State social and economic interests. Congress has repeatedly endorsed coal-fired generation and energy diversity. For example, then-EPA Administrator Douglas M. Costle wrote in 1979 that "one of the basic purposes of the 1977 Amendments" to the Clean Air Act was "encouraging the use of higher sulfur coals" and "domestic coal reserves."[62] More recently, the 2005 Energy Policy Act promoted a national investment to advance the "efficiency, environmental performance, and cost competitiveness" of coal-fired generation and "promote...energy security, diversity, and economic competitiveness benefits that result from the increased use of coal[.]"[63] The Emergency Economic Stabilization Act of 2008 extended tax credits for producing electricity from wind, biomass, solar energy, hydropower, and other sources, but also allowed a "30% investment tax credit rate for advanced coal-based generation technology projects" and coal gasification projects and created a new tax credit for $CO_2$ sequestration.[64] Congress has also acted to shelter local and regional economic interests from the potential effects of environmental regulation. The Clean Air Act authorizes state governors, the Administrator, and the President himself (or his designee) to protect communities from "significant...economic disruption or unemployment" that might result "from using fuels other than locally or regionally available coal or coal derivatives to comply with implementation plan requirements."[65] By moving forward with this rulemaking, EPA would undermine and violate these longstanding Congressional policies.

"The language of section 111...gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense at the national

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[61] 77 Fed. Reg. at 22,395.

[62] Douglas M. Costle, New Source Performance Standards for Coal-Fired Power Plants, 29 J. AIR POLLUTION CONTROL ASS'N 691-92 (1979).

[63] 2005 Energy Policy Act, §§ 402(a) and 421 (promulgating 42 U.S.C. §§ 15962 and 13571-13574); see also U.S. Dept. of Energy, Clean Coal Technology & The Clean Coal Power Initiative, www.fossil.energy.gov/programs/powersystems/cleancoal/.

[64] H.R. 1424, 110th Cong. (2008), CRS Summary.

[65] 42 U.S.C. § 7425(b).

and regional levels [.]"[66] EPA's selection of NGCC as BSER ignores the vast cost and energy impacts that that choice would create. For these reasons as well, EPA should withdraw its proposal, as its application to coal-fired steam electric generating units would conflict with and undermine Congressional efforts to increase energy diversity and protect local coal-based economies.

## III. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

EPA must provide an expanded assurance that this rulemaking for new sources rule will not be applicable to and will not affect existing sources.

### A. The proposed NSPS does not apply to modified or reconstructed sources

EPA devotes less than two pages of the preamble to an explanation of the interrelationship between this NSPS and modified, reconstructed, or other existing sources currently subject to Subparts Da and KKKK.[67] Nothing in those two pages explains EPA's legal basis for adopting a standard that applies to only a portion of the sources subject to regulation under Section 111(b). While AEP agrees that EPA does not have sufficient information to regulate existing sources in either of the current Subparts, that lack of information simply illustrates the infirmity of the analysis EPA has performed in developing its "new source" standard.

In the development of prior NSPS standards, EPA has relied on a robust set of data from newly permitted sources within a source category to demonstrate that the performance of a particular system or set of technologies is available at a reasonable cost for both newly constructed and modified or reconstructed sources. That is, EPA relied on actual operating data to demonstrate that the standard is demonstrated and the cost of implementing the standard is reasonable.

No similar set of analyses could be undertaken in support of this standard. No examples are cited where an operating fossil fuel-fired unit of any type was modified in order to achieve the proposed standard, nor has EPA identified any technologies that could be applied to any

[66] Sierra Club v. Costle, 657 F.2d 298, 330 (D.C. Cir. 1981).
[67] 77 Fed. Reg. at 22400-22401.

existing unit that would allow it to achieve the proposed standard. Were EPA to undertake such an analysis, it would find that achievement of the proposed standard is infeasible. Even in a case where proposed changes to an existing source exceed 50% of the cost of an entirely new unit, the proposed standard would require building a new NGCC from the ground up.

### B. The proposed NSPS is not a BACT floor

In addition to the need for greater clarity on the treatment of "modified" and "reconstructed" sources under Section 111, EPA must provide greater regulatory certainty that this NSPS will not be relied upon to drive fuel and technology choice in the Prevention of Significant Deterioration (PSD) program. EPA claims that its proposal does not amount to a mandate of any particular choice of technology and fuel, but currently, EPA's guidance document on PSD permitting for GHG notes that

> "To the extent EPA completes an NSPS for a relevant source category, BACT determinations that follow will need to consider the levels of the GHG standards and the supporting rationale for the NSPS."[68]

> "While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final." [69]

If EPA intends to deviate from this practice, it must provide a legal and technical justification that will withstand scrutiny by a reviewing court and can be relied on by state permitting authorities. This guidance document should be updated and made available for public comment to ensure that the guidance aligns with the provisions in the final NSPS to ensure that existing sources that trigger the Tailoring Rule requirements are not subject to a standard applicable to new sources. Any final NSPS for new sources must not establish the BACT floor for existing source projects that are applicable to the PSD permitting program, because EPA has not justified such a standard or conducted an adequate analysis to support such a program. Although EPA has noted that:

> "CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other

[68] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 21.
[69] Id. p. 64.

GHG controls. Even if not eliminated in Step 2 [Technical Feasibility Analysis] of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 [Economic, Energy, and Environmental Impacts Analysis] of the BACT analysis, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible."[70]

EPA also notes that "CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources." p.32 In part because of the position that the technical feasibility and cost-effectiveness challenges will be difficult to overcome, EPA's guidance suggests that CCS will not be BACT:

"While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[71]

"We expect many permits issued after January 2, 2011, to initially place more of an emphasis on energy efficiency, given the role it plays in affecting emissions of GHGs."[72]

The logical conclusion to draw from the analysis presented by EPA is that no NSPS is practicable at this time, at least for those sources in Subpart Da. Such a results would more closely conform to the available data, and be consistent with past practice. Given the existing guidance EPA has issued, such a result would allow CCS to continue to be considered as part of the technology review in BACT analyses, without burdening sources with the inevitable challenges that will result from EPA dramatically different approach in developing this NSPS. However, if EPA maintains the structure as proposed, a sound legal justification and fuller factual predicate for the conclusion EPA has reached, that the proposed standard has no applicability to existing sources, must be clearer and adequately justified before the rule is finalized.

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[70] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 42-43. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[71] Id. p. 36

[72] Id. p.45.

## IV. EPA's proposed rule is based on faulty data

Additionally, EPA's methodology for assessing the costs and benefits of this proposed rule is incomplete and factually disconnected from scientific and economic realities. EPA acknowledges that "ideal benefit-cost analysis would first model projected generation capacity and capacity additions for every plausible set of market conditions[.]"[73] However, EPA did not conduct this analysis. Instead of a robust scenario analysis, EPA relied upon hypothetical examples and illustrations. Policymakers and the public need to be fully informed of the potential costs of this proposed rule. A more detailed scenario analysis needs to be performed using the best available data.

### A. Cost analysis

EPA's erroneous conclusion that this policy will have negligible costs or impacts on society is based on the flawed premise that no new coal plants will be built absent this rule. This finding is incorrect for several reasons.

First, EPA acknowledges that there are a number of existing projects for coal-fired power plants that have not yet "commenced construction," but that are well along in the permitting process and have made significant investments. EPA proposes to treat these projects as a special category of "transitional" plants that will not be subject to the standards if they commence construction within 12 months of the date of the proposal. EPA makes no effort to examine the feasibility or cost of any one of these plants actually complying with the proposed standard. EPA also arbitrarily examined the costs of the rule only through 2020. This is a significant and glaring error, in that electric generation facilities typically have life spans of 40 years or more. An appropriate assessment of the cost of the policy would use a similar time span.

Second, new baseload generating capacity takes a number of years to plan, permit, engineer and construct. Even assets coming online after 2020 will have to be planned within the next few years and will be subject to this proposed standard. EPA argues that the fact that it is required to review the NSPS within eight years renders post-2020 analysis irrelevant. However, many potential plants planned **before** 2020 and subject to the NSPS won't come on line until

[73] EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units ("RIA") at 5-27 (Mar. 2012).

after 2020. Thus, EPA's conclusion that the proposal imposes no costs and has no impacts on society is baseless.

Third, truncating the analysis based on a presumed future is at odds with previous EPA assertions that it will not speculate on future rulemakings in its modeling efforts. EPA states in the documentation for the IPM results that the base case represents "a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized."[74]

Fourth, while EPA has recently promulgated or proposed rules that will collectively increase the cost of coal-fired generation, a disguised regulatory agenda that effectively bans new coal-fired generating units is not a valid reason to consider the NSPS proposal costless. Finally, the modeling of costs only until 2020 is inconsistent with the notion that new coal-fired facilities have the ability to average emissions over a 30-year timeframe.

Equally troubling is EPA's reliance upon a single point forecast of projected new generation using coal and natural gas prices that run out to only 2020. It is impossible to say that new coal-fired generation is not going to be cost-effective in the future based on a single modeled outcome or without considering potential coal and gas prices in the post-2020 time period. Other scenarios recently developed by EPA and EIA indicate that, under different market conditions, new coal units may in fact be built post-2020.[75] However, EPA made no effort to quantify the impacts of these alternative scenarios, due to the arbitrarily truncated period for which it chose to analyze cost impacts. Costs for alternative scenarios should be quantified going forward.

Trends in planned and projected generation tend to oscillate substantially, due to the volatility in fuel commodity markets. As an example, only four years ago, in the 2008 Annual Energy Outlook, EIA forecast 89 GW of new unplanned coal additions by 2030. Just six years ago, in the 2006 Annual Energy Outlook, EIA forecast 145 GW of unplanned coal additions. Immediately prior to those forecasts, however, there was an unprecedented build-out of new natural gas combined cycle capacity, with the belief that those facilities could displace coal. Thirty years prior to the natural gas build-out, there was a similar boom with nuclear power,

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[74]www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter1.pdf.
[75]See www.epa.gov/airmarkets/progsregs/epa-ipm/proposedEGU_GHG_NSPS.html, and www.eia.gov/oiaf/aeo/tablebrowser/.

accompanied by the prediction that nuclear energy would be "too cheap to meter." These previous forecasts and historical build cycles illustrate that future generation options and projections are extremely sensitive to future commodity pricing, regulatory requirements, and external events. A myopic view of these influences leads to wasteful and disruptive boom and bust cycles in generation development.

The electric utility industry is currently in a unique period in which material (*e.g.*, steel and concrete) and fuel costs for coal-fired generation have seen dramatic increases at the same time that natural gas prices have reached record lows not seen in the past decade and the demand for electricity has been suppressed due to the prolonged recession and benign weather. However, many analysts expect natural gas prices to rise significantly in the future, as the near term glut of natural gas eventually dissipates. Indeed, the MATS rule and CSAPR rule will force retirement of otherwise economical coal-fired capacity that, under EPA's April 13, 2012 proposal, can only be replaced with NGCC technology, which will sharply increase natural gas demand in a compressed time period. In short, current natural gas prices are as low as they are due to short-term phenomena. Those low prices cannot be expected to be sustained over the long term.

Natural gas pricing has historically been extremely volatile and is the largest determinant of what type of new electric capacity will be built, due to its strong correlation with power pricing. EPA's RIA states on page 4-21 that:

> The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). Over the last decade, gas prices (both Henry Hub prices and delivered prices to the power sector) have ranged from $3 per mmBtu to as high as $9 on an annual average basis.

AEP agrees with this statement and notes that international natural gas prices also have historically experienced seasonal and annual volatility that have resulted in significant spikes for periods of time. The extreme volatility in natural gas pricing should lead to the logical conclusion that structuring the cost benefit/analysis for this rule on a single gas forecast extending through only 2020, with prices at their lowest levels in fifteen years, is not a rational or prudent approach. Thus, multiple natural gas price trajectories should be examined in conjunction with the cost analysis for the rule.

While EPA did examine the role that somewhat higher electricity sales and lower yields from shale gas could have on new capacity decisions, there are other factors that could have even more dramatic impacts on natural gas pricing and new build economics. For example, a move to gas liquefaction and export within either the United States or Canada has the potential to drive up domestic natural gas prices to levels seen internationally, which can be 3 to 4 times higher than current domestic prices.[76] EPA's IPM model does not take into account the development of these facilities, even though announced facilities and current market conditions suggest they will be developed. Additionally, a drop in world oil prices could slow down oil and natural gas liquids production activities, reducing the supply of associated gas and increasing the price of natural gas. Furthermore, EPA's economic modeling to date has not appropriately assessed the impacts of the final MATS rule and other pending regulations, which will lead to the retirement of many coal-fired generating units, further increasing the demand and hence the price for natural gas. The associated reduction in coal use will also influence coal pricing (and reduce coal prices), making new coal fired generation more viable economically. Notably, when spreads between gas and coal prices reach approximately $4 per mmBtu, baseload coal plants become economic to build relative to combined cycle gas plants. Historically there have been many periods where these spreads have existed between gas and coal prices, such as the period from 2003 to 2008. Thus, shale gas recovery levels are only one of multiple factors that could influence natural gas pricing. A broader range of scenarios needs to be explored within the cost-assessment. For each scenario, the cost of this regulation should be assessed, using at least a 30 year time horizon.

### B. Selection of 1,000 lb $CO_2$/MWh emission rate

EPA makes the broad assumption that new Natural Gas Combined Cycle ("NGCC") units can meet its proposed standard of performance, which is 1,000 lb $CO_2$/MWh of electricity generated on a gross basis. However, a recent study has indicated that many smaller plants will not be able to meet this standard.[77] Additionally, even efficient units could have trouble meeting

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[76] Richard Bass and Gordon Pickering, *The U.S. Has a Natural Gas Glut; Why Exporting It As LNG Is A Good Idea*, ENERGY SOURCE (June 13, 2012), http://www.forbes.com/sites/energysource/2012/06/13/the-u-s-has-a-natural-gas-glut-why-exporting-it-as-lng-is-a-good-idea.

[77] See Matthew J. Kotchen and Erin T. Mansur, How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?, at 9 (Apr. 25, 2012), available at http://www.dartmouth.edu/~mansur/papers/kotchen_mansur_co2standards.pdf (finding that "71 percent of the

the standard if gas prices should increase, changing the duty cycle of the units and creating additional inefficiencies associated with cycling or ramping of output. EPA should include in its modeling the additional costs of having to build larger and more efficient units to cope with temporary, intermittent, or unexpected operating conditions. EPA should also conduct a detailed analysis of the effect of unit cycling on meeting the standard. If units must be forced to run even if their cost of operation exceeds the power price in order to meet the efficiency standard, the increased operational cost should be considered in the cost analysis.

### C. IPM modeling

In addition to the fundamental flaws in the cost analysis, EPA also made several critical errors in its development of the IPM model and runs used in support of the cost analysis. One major flaw in the IPM model is the double counting of $CO_2$ risk exposure. As stated in the RIA on page 5-15, "both EIA and EPA include a capital charge rate adder (3 percent) for new conventional coal-fired generating capacity without CCS, which reflects the additional cost of raising capital that is currently reflected in the marketplace, related at least in part to uncertainty surrounding future greenhouse gas emission reduction requirements." Because this proposed NSPS removes much of the uncertainty regarding GHG emission reduction requirements by setting a standard, this penalty should be reduced or removed altogether in the modeling of the reference case for comparison purposes. The use of this penalty in the reference case is an inappropriate bias against new coal generation.

EPA's model is also flawed due to its misrepresentation of compliance planning decisions within the electric sector. For example, EPA's projections for unit retirements due to the CSAPR and the MATS Rule are significantly below what industry has already announced in response to these rules.[78] This is due in large part to EPA's failure to model other pending regulations that could affect electric generators, including Coal Combustion Byproducts (CCB), 316(b) water regulations, regional haze, and potential $CO_2$ regulations. Due to EPA's failure to consider the impacts of these regulations under development, in contrast to the broader view utilities must take in their compliance planning, EPA vastly underestimates the amount of new

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[combined cycle gas turbine] units scheduled to come on line through 2017 would have $CO_2$ emission rates that meet the target").

78 www.americaspower.org/sites/default/files/may-issuespolicies/Coal-Retirements-Talking-Points-and-Table-April-28.pdf.

electric generating capacity that will need to be brought online over the next decade. Should natural gas units be the preferred generating technology, the impact of the new capacity on natural gas pricing and infrastructure build out requirements also needs to be modeled within IPM as well.

The IPM model also uses outdated capital cost inputs associated with new generation sources. EPA estimates that new natural gas combined cycle generation will cost $976/kW in 2007 dollars.[79] This is substantially lower than estimates by the Electric Power Research Institute (EPRI), the leading not-for-profit research arm of the electric utility industry, of $1275–1375/kW in 2010 dollars.[80] Even correcting for inflation, EPA's capital cost is ~20 to 25% lower than EPRI's estimate. Conversely, EPA projects that a new pulverized coal plant will cost $2,918 – $3,008/kW, in comparison to EPRI's cost of $2,400 – $2,760/kW. In this case, EPA's cost of new coal generation is ~15 to 30% higher than EPRI's estimates. In both cases, these flawed cost estimates artificially bias the model to new gas generation in lieu of coal generation by overstating the cost of coal capacity and understating the cost of gas capacity. This discrepancy should be corrected within IPM going forward.

**D. Levelized cost analysis**

The levelized cost of electricity projections developed by EPA and cited from EIA within the RIA also present a fundamentally flawed perspective as to the relative cost of new generation. The United States operates an interconnected grid in which generators dispatch on variable cost, with lower cost sources dispatching more frequently. Over the long run, coal generation will dispatch more frequently than gas generation due to lower fuel and variable operating costs. Thus, EPA and EIA's assumption that new coal units and new natural gas units will have the same or similar operation and capacity factors is incorrect. EPA should revise the levelized calculations to include more reasonable assumptions for natural gas plant operation in the IPM, including examining the average capacity factor of new units operating over their first 20 years of operation, particularly in light of increasing state renewable energy requirements requiring increased cycling of other generating assets.

[79] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter4.pdf.
[80] EPRI, Program on Technology Innovation: Integrated Generation Technology Options - Technical Update (June 2011).

EPA's misrepresentation of unit capacity factors results in an erroneous calculation of the fixed charges that need to be recovered. Together with the errors in capital cost and coal capital charge rate adder mentioned previously, EPA's statement that "only when gas prices reach approximately $9.60/mmBtu (in 2007 dollars)…[does] new coal-fired generation without CCS become[] competitive"[81] is patently false. In fact, both EPA and EIA models show new coal being built in various sensitivity cases, even though EPA states that "none of the EPA or EIA sensitivities with alternate assumptions for natural gas approach this price level."[82] These new coal builds occur within the model, even given the input errors that create biases against new coal, due to the model correctly calculating the cost of new generation based on actual operation and taking into account the relative escalation of natural gas prices versus coal prices over the life of the plant.

**E. Benefit analysis**

It is arbitrary for EPA to propose a rule with no substantive quantifiable benefits. As stated on page 5-19 of the RIA, "EPA anticipates that the proposed EGU GHG NSPS will result in negligible $CO_2$ emission changes, energy impacts" or "quantified benefits." The absence of any benefit confirms that there is no reason to propose the rule, which establishes a de facto ban on coal fired generation across a range of plausible energy futures. Even though there is no scenario in which quantifiable benefits can be calculated, there are massive potential negative impacts from the policy, should coal be effectively removed as a choice for new generation.

EPA ineffectively tries to qualitatively describe two potential tangential benefits that "may" occur, but presents a flawed argument in support of their inclusion. The first "benefit" cited by EPA is that the NSPS provides legal assurance that any new coal-fired plants must limit $CO_2$ emissions, as the "rule prevents the possible construction of uncontrolled, high-emitting new sources that might continue to emit at high levels for decades[.]"[83] This is a completely flawed argument, as EPA's current regulations address $CO_2$ emissions from new sources under its Greenhouse Gas Tailoring Rule. The proposed rule simply further constrains new coal-fired units by relying on the performance of natural gas combined cycle technologies to prescribe standards that cannot in fact be achieved at coal-fired units and do not represent best

[81] RIA at 5-17.
[82] Id.
[83] RIA at ES-3.

demonstrated technology for such units. Allowing for further development of alternative approaches to greater $CO_2$ reductions through the case-by-case analysis required by the Tailoring Rule would foster greater technological development without unnecessarily constraining fuel choice.

The second claimed benefit is that this rule reduces regulatory uncertainty. However, this proposal will create even *greater* uncertainty, in particular due to its novel treatment of existing modified and reconstructed sources. As an example, EPA is relying on its purported authority to promulgate a "new source" standard that does not apply to "modified" units (notwithstanding the controlling definition of "new source" in Section 111(a)(2) of the CAA) during a period when other EPA regulatory initiatives will require existing coal plants to undertake physical and operational changes in order to achieve reductions in criteria pollutant emissions that are known to increase the hourly rate of $CO_2$ emissions from coal-fired steam generators. EPA claims that such sources will be protected by the "pollution control project" exclusion in 40 CFR § 60.14(e)(5). EPA acknowledges that this exclusion (dating to 1975 in the NSPS program) is similar to a provision subsequently promulgated under the new source review regulations in Part 51, and that the D.C. Circuit Court's decision in *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005), invalidated that similar provision in the new source review program. The questionable continuing validity of the pollution control exclusion may well force additional coal unit retirements, beyond the ~53,000 MW already announced, even though EPA has acknowledged that it has insufficient information to develop standards that could apply to existing sources.

Even if a source were willing to undertake such a risk and accept that installation of additional criteria pollutant controls would eventually require the capture and storage or sequestration of $CO_2$, uncertainty persists regarding the availability of adequate sequestration sites within reach of existing units, the actual performance of available capture technologies, the actual performance of long term sequestration operations, and the long-term regulatory framework for liability. EPA touts the use of DOE funding for CCS projects. However, the DOE has repeatedly pulled funding from its FutureGen project. DOE funding alone has been insufficient to allow half of the award recipients to continue with planned projects and depends upon an appropriation system that is subject to the federal budgeting process. AEP's own experience with a DOE-funded project is discussed in greater detail in Part IV of these comments.

The preamble to EPA's proposal includes a highly speculative section commenting on potential external societal costs relating to various generating technologies. While this section is not intended as a firm calculation of benefits, it presents a biased picture of societal costs and fails to adequately express the uncertainty surrounding the underlying calculations. Furthermore, this analysis is based on the flawed levelized cost of electricity calculations mentioned previously.

For this highly speculative analysis, EPA uses the Societal Cost of Carbon (SCC) developed in 2010,[84] even though it is widely acknowledged that these cost estimates are inaccurate. EPA acknowledges in the RIA that "any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional."[85] As such, these calculations cannot form the basis of an adequate RIA.

EPA also presents calculations for $NO_x$ and $SO_2$ using a benefit per ton reduced standard that suffer from additional flaws. National Ambient Air Quality Standards (NAAQS) are designed to protect health and welfare with an adequate margin of safety. Additional reductions of these pollutants in areas of the country that attain these health-based standards should not have **any** quantifiable health benefit. Additionally, the modeling and calculations presented by EPA ignore the projected impacts of the MATS Rule on air quality, which in many cases will drive emissions below the Lowest Measured Levels (LML) in the studies used to support the health claims, thus invalidating the applicability of the studies to a benefit calculation. Furthermore, the Pope et al. and Laden et al. studies which underpin many of the EPA health benefit estimates[86] are dated pieces, using older air emissions and other data from the 1980s and 1990s that do not take into account current emission levels or trends (which indicate, for example, that air emissions are 3 to 5 times lower than when these studies were conducted). Nor do these older data studies differentiate health response between various species of fine particulate matter even though more recent studies show associations between locally produced carbonaceous compounds but *NO* associations between utility produced $SO_2$ and $NO_x$ emissions.[87]

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[84] See RIA, 5-28 through 5-30.
[85] Id. at 5-23.
[86] See, e.g., RIA at 5-30.
[87] Examples include: (1) Grahame TJ, Does improved exposure information for PM2.5 constituents explain differing results among epidemiological studies? Inhal .Toxicol. 21: 381-393 (2009); (2) Lipfert FW, Wyzga RE, Baty JD, Miller JP, Air pollution and survival within the Washington University-EPRI veterans cohort: risks based

Given the acknowledged limitations of the analyses presented, EPA should not include any health benefits within the RIA as any such benefits are indirect and speculative. Furthermore, EPA should update its calculations of health benefits to include the latest scientific literature, which include newer peer-reviewed studies showing no association between PM and mortality and significant issues with the methods used in the Laden et al. study.[88]

## V. Carbon Capture and Storage Is Not Commercially Available For Coal-Based Generation and Will Not Become a Viable Control Option Until Significant Challenges Are Addressed

EPA notes that it "does not prescribe a particular technological system that must be used to comply with the standard of performance" and that "sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions."[89] Practically speaking, though, CCS is the *only* control option *potentially* available for new coal-based generation to meet the proposed limits. EPA's extensive discussion in the proposed rule of the technical feasibility, commercial status, and availability of CCS exposes the total reliance of the proposed rule on this single technology for compliance by coal-fired EGUs. In fact, EPA notes that "by clarifying that, in the future, new coal-fired power plants will need to implement CCS, this rulemaking eliminates uncertainty about the status of new coal."[90]

The problem with EPA's reliance on CCS is that CCS is not commercially available for coal-based generation and faces significant technical, financial, regulatory, and legal barriers that must be addressed before it becomes a viable $CO_2$ emission control option. AEP considers "commercially available" technologies as those that can be purchased from a vendor, have been proven at commercial scale on a representative application, and are furnished with robust guarantees on performance and reliability. Based on these criteria, CCS is not commercially available. In fact, at the current pace of development, CCS technology will not be available for *at least* a decade. CCS development barriers and opportunities for addressing them have been identified by numerous private and public efforts (e.g., President Obama's Interagency Task

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on modeled estimates of ambient levels of hazardous and criteria air pollutants. J Air Waste Manag Assoc., 59(4):473-89 (Apr. 2009); and (3) Grahame T, and Hidy GM, Pinnacles and Pitfalls for Source Apportionment of Potential Health Effects From Airborne Particle Exposure, Inhal .Toxicol. 19: 727-744 (2007).

[88] Graven et al., An Approach to the Estimation of Chronic Air Pollution Effects Using Spatio-Temporal Information, Journal of the American Statistical Association (2011).

[89] 77 Fed. Reg. at p. 22,402.

[90] Id. at p. 22,399.

Force, the Secretary of Energy's National Coal Council, and the Department of Energy's research and development programs); by AEP, through our efforts in operating the first integrated CCS project in the world on a coal-based generation unit; and even by EPA, in the proposed rule and in dealing with air permitting issues for greenhouse gases. The following sections provide an expanded discussion of accumulated knowledge about the development barriers that remain for CCS, and demonstrate that the proposed $CO_2$ NSPS for coal-based generation is technically flawed because no commercial control options, including CCS, are available now or will be available in the near-term to meet the proposed standard.

Considering the state of the technology, EPA's reliance on the current and predicted near-term availability of CCS as a viable option to meet the proposed NSPS is premature and does not align with the many practical estimates of the expected timeline for developing the technology. EPA's proposed approach effectively precludes future consideration of electric generation options that must rely upon CCS to meet the proposed standard. EPA should establish standards for new coal-based generation that are specific to coal without the use of CCS and that are premised on the best demonstrated efficiencies that have been achieved in practice by advanced coal technologies.

**A. Technically feasible is not the same as commercially available**

Varying degrees of technical feasibility can be demonstrated based on desktop calculations, laboratory studies, pilot-scale testing, large-scale demonstrations, or other methods. However, a process that is technically feasible is not necessarily commercially viable or available.[91] A determination of commercial availability cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial scale, allows for the optimization of systems integration and performance, and provides for cost-effective design options that can be safely and reliably operated. Absent this development process, a technically feasible process remains just that – only technically feasible and no more. Research and development continues, but CCS has yet to be demonstrated to be commercially available for coal-based generation. The scope of obstacles to commercial availability, coupled with the magnitude of cost and time for addressing them, are significant and have been widely acknowledged.

[91] Technical feasibility, by itself, is insufficient to satisfy the BSER criteria in section 111(a) of the Clean Air Act.

Despite these recognized development short-comings, EPA concludes in the proposed rule that CCS is technically feasible and minimizes any remaining development risks based on a variety of factors including the experience of other industries, conceptual design of CCS systems that have yet to be constructed or demonstrated, and an overly simplistic assessment of the challenges to initial and broader commercialization.[92] EPA suggests that "the cost of $CO_2$ capture and compression represent the largest stumbling block to widespread commercialization of CCS."[93] EPA also notes that although they "expect the cost of CCS to decline, we [EPA] recognize that the amount of the decrease is uncertain."[94] If magnitude and rate of cost reductions is uncertain, then so are the prospects that the "largest stumbling block" to commercialization has been adequately identified, let alone that it will be sufficiently addressed at *any* point in time for a new source to rely on CCS as a viable control option. While lowering capture costs certainly is a significant challenge, it is only one of many significant challenges that impede the commercial availability of CCS. EPA's focus on capture costs in the proposed rule grossly understates the breadth of barriers to rapid commercial development by minimizing the significant technical challenges that exist for *capture* systems and by overlooking the equally significant technical, cost, and legal challenges with *transport* and *storage* systems, which are discussed in the sections below.

**B. Significant technical, financial, regulatory, and legal barriers exist that must be addressed before CCS is commercially acceptable for coal-based generation**

Many proponents of limiting $CO_2$ emissions point to CCS as the primary means of accomplishing this objective. AEP has been a strong advocate for the development and advancement of CCS technologies, as demonstrated by our extensive work at the Mountaineer Plant. Furthermore, AEP believes that technological solutions are critical to reducing emissions from or improving the reliability and availability of electricity production. Nonetheless, as a consequence of our first-hand experience and intimate understanding of the technologies, AEP is

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[92] See e.g., 77 Fed. Reg. at 22,415 ("processes....to separate $CO_2$ from other gases have been in use since the 1930's"); 22,414 ("[EPA's] position is that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available") ; and 22,396 ("new coal-fired power plants with CCS are being permitted and built today").
[93] Id. at 22,415.
[94] Id. at 22,419.

convinced that CCS is many years from providing a commercially viable solution to reducing $CO_2$ emissions.

"Commercially available" technologies are those that can be purchased from a vendor, have been proven at commercial scale on a representative application, and are offered complete with robust guarantees on performance and reliability. Vendors cannot provide meaningful guarantees without extensive testing at representative scale. Based on this definition, there are no commercially available technologies for the capture of $CO_2$ from coal-based power plants. The Department of Energy's Major CCS Demonstration program currently includes twelve projects that propose to demonstrate $CO_2$ capture and some form of storage and/or utilization of the captured $CO_2$.[95] If this were a list of twelve successfully completed projects, then it could certainly be argued that the technologies are ready for commercial deployment. However, not one of the projects has been completed, and in fact, none have even commenced operation. Most are no more developed than the work on paper required for conception of the project. Moreover, some that had previously been included on DOE's list have been cancelled or delayed indefinitely. And, on a global scale, the United States leads all others in work done to date and proposed future projects. Simply put, the technologies to capture and sequester $CO_2$ are not commercially available today.

While several promising $CO_2$ capture technologies are being developed, none are ready for commercial deployment; rather, they must be advanced in a systematic and step-wise manner. AEP had begun the process of moving the technology to commercial scale, but the lack of an adequate funding mechanism resulted in the company placing the project on hold. Even if AEP's project had remained on schedule, commercial-scale deployment of the chilled ammonia process in a first-of-a-kind large-scale unit would not be in service before 2015. The AEP unit, like other first-of-a-kind projects, would have been installed without any commercial guarantees from vendors and would have run the risk of not continuously or reliably achieving high $CO_2$ capture levels. AEP's expectation was that a commercial-scale CCS demonstration project was essential *now*, so that in 2020 or later, a reliable commercial-scale $CO_2$ capture system *might* be commercially available and ready for deployment. With the suspension of the AEP project and as similar DOE projects are delayed or discontinued, the date for commercial readiness of CCS

[95] See U.S. Department of Energy, National Energy Technology Laboratory (NETL), Major Demonstrations, Industrial Capture and Storage (ICCS): Area 1, www.netl.doe.gov/technologies/coalpower/cctc/iccs1/index.html.

technology continues to move further out on the horizon. A reasonable estimate for commercial availability, based on the current state of technology development and as discussed in Section C. below, is *at least* ten years away, and this is assuming that current financial and regulatory barriers to demonstration projects are immediately removed. Without a clear path forward, we will remain, perhaps indefinitely, *at least* ten years or more from commercialization of $CO_2$ capture technology.

Besides the time required to demonstrate technology maturity, CCS developers must also tackle numerous technical challenges associated with both $CO_2$ capture and geologic sequestration. On the capture side, energy demand, physical space requirements, power plant integration, and flue gas compatibility all pose formidable obstacles to overcome. Some of these challenges are summarized below.

- Energy consumption requirements represent the single most daunting barrier to economical deployment.
- The sheer size of the equipment brings its own set of concerns. The current configuration more than doubles the power plant footprint, representing substantial construction challenges and project cost implications.
- Due to the magnitude of energy requirements, integrating these systems into plant designs and process flow schemes provides unprecedented engineering and operations challenges.
- Certain $CO_2$ capture systems have chemistry requirements that demand pristine flue gas conditions, in some cases well beyond the capability of state-of-the-art flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems.

These four points cannot be addressed merely with paper studies or engineering exercises and specifications. It is critical that solutions to these very real challenges are developed and physically demonstrated, with proven performance at full scale, and exposed to the full gamut of commercial power plant conditions, before operators can consider full-scale technology deployment on commercial electricity generating units.

There also remain many unresolved technical challenges related to $CO_2$ sequestration and/or utilization. The availability of suitable saline formations, injection pressure limitations, and ultimate storage capacity are all currently the subject of intense study and lack large-scale data for proof-of-concept soundness. Monitoring and verification of the $CO_2$ plume extent and assurance of confinement requires technologies that have not yet been proven in representative applications. While help from the oil exploration and production industries is certainly beneficial, there is no substitute for the operation of numerous large-scale demonstration projects involving $CO_2$ injection into saline and other formations. Geologically-based computer models must undergo time-consuming, expensive, and rigorous validation in order to be proven reliable, so that they can be used in lieu of the exorbitantly high costs of installation of large numbers of monitoring wells. In the near term, Enhanced Oil Recovery ("EOR") projects offer potential opportunities to put captured $CO_2$ to economical use, but these operations are also faced with substantial challenges associated with validation and accounting for $CO_2$ storage permanence. Current and past EOR practices have not been required to demonstrate permanent $CO_2$ storage. In fact, EOR operators have been economically driven to minimize the quantity of $CO_2$ left underground in favor of reusing it in other recovery operations.

AEP's CCS demonstration program, again, is an example of the systematic nature of these projects, taking the technology in step-wise fashion from small-scale to commercial-scale deployment. The timeline for this work points again toward the need for at least another ten years of development and demonstration for wide-scale application of the technology. In summary, CCS technology is not yet ready for wide-scale and large $CO_2$ capture mandates. Continued research, development, and demonstration must be supported and is essential to make CCS technologies a reality in the next decade.

Further, the path to CCS commercialization also faces significant regulatory and legal barriers. These include issues related to the ownership of, acquisition of, and/or access to geologic pore space, as well as issues surrounding long-term liability and stewardship of geologically stored $CO_2$. Resolution of these barriers in many cases will be through the development of state legislation and regulatory programs. Efforts at the state and federal level are underway and at various levels of progress, but significant challenges remain before a variety of legal and regulatory issues may be sufficiently resolved to support the commercialization of CCS on coal-based generation.

### C. Numerous public and private organizations have concluded that CCS for coal-based generation is not commercially available and that significant development barriers remain

Numerous studies and projects by public and private organizations recognize that CCS is not commercially available for coal-based generation and that significant development barriers remain. For example, a November 17, 2011 article by Reuters noted that "[EPA Administrator Lisa] Jackson, whose agency looked at CCS as it developed the rules, said the technology has a long way to go. 'It can be years, maybe a decade or more, until we have the technology available at commercial scale,' she said."[96]

While research, development, and demonstration ("RD&D") programs continue, the current scope and pace of these efforts is insufficient to drive the near-term commercial availability of CCS. Results from many of these studies indicate that the availability of commercially available CCS technology is *at least* a decade or more away, *even if* a much more ambitious RD&D program were implemented. Appendix A summarizes some of these studies to highlight the state of CCS technology development and to demonstrate that reliance on the availability of CCS as a viable $CO_2$ control strategy to meet either the proposed annual or 30-year average NSPS limit is premature.

### D. AEP's experience demonstrated both the potential of CCS and the significant challenges that still must be addressed

From 2009 to 2011, AEP operated the first integrated CCS project in the world on a coal-based generation plant. The lessons learned from that effort uniquely position AEP to comment on the potential of CCS technology and the significant remaining developmental challenges that must be addressed before CCS can be considered commercially available. The following summarizes AEP's CCS experience at the Mountaineer Plant, a 1,300 MWe coal-fired generating unit in New Haven, West Virginia.

A number of qualifications must be made in order to properly understand what was and was not accomplished by AEP at the Mountaineer Plant. First, EPA claims that "the AEP Mountaineer project showed that CCS can be successfully retrofitted into an existing plant."[97]

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[96] www.reuters.com/article/2011/11/17/usa-epa-carbon-idUSN1E7AG0WU20111117.
[97] 77 Fed. Reg. at 22,425.

Taken out of context, this claim is misleading. The term "retrofit" does not mean that a commercial-scale CCS system was constructed and operated at the Mountaineer Plant. AEP successfully deployed a $CO_2$ capture system on a validation-scale (20-MWe, or 1.5% of Mountaineer's 1,300-MWe) slip-stream process. The success of that project was in proving that the technology was compatible with power plant conditions and that the technology could successfully capture $CO_2$ at a coal-fired power plant. The project *did not prove* that CCS technology can be successfully operated at commercial scale or that it is commercially available. AEP did consider a commercial-scale project, but after performing a front-end engineering and design ("FEED") study and being unable to obtain necessary cost-recovery approval from regulators, decided to cancel the project.[98] It should be clearly understood that the validation *does not* constitute a commercial demonstration and that the technology *is not* to be considered commercially available.

AEP partnered with Alstom to validate the chilled ammonia process for capturing $CO_2$ from the Mountaineer Plant. The 20-MWe slipstream system was initially operated on September 1, 2009, and continued through May 31, 2011. Over that period, the chilled ammonia process captured more than 50,000 metric tons of $CO_2$. Because the system was built as a validation platform, with all the flexibilities necessary for systematic process adjustments, it was not optimized for maximum energy efficiency. This design enabled operators to fine-tune and control all process streams and energy inputs to thoroughly evaluate the technology. Once completed, the AEP/Alstom team developed a comprehensive understanding of the chilled ammonia process and specifics about the operation of each system within the process. This in-depth knowledge, including a detailed understanding of key process parameters such as energy penalty, reagent loss, and $CO_2$ capture rate, enabled the team to move forward with an engineering study and preliminary design for a commercial-scale deployment at the same power plant.

While the capture process has been shown to be technically feasible under coal-fired power plant conditions, there are many important aspects of the technology that must be demonstrated at full-scale (a minimum of approximately 250-MWe, or more than 12 times the size of the validation system at Mountaineer) before a process supplier or power plant owner can

[98] The Final Technical Report for the commercial scale CCS project can be found at www.netl.doe.gov/technologies/coalpower/cctc/ccpi/bibliography/demonstration/ccpi_aep/MTCCS%20II%20Final%20Technical%20Report%20Rev1.pdf.

realistically consider deploying the technology commercially. For example, chilled ammonia, and any other post-combustion $CO_2$ capture process, uses enormous quantities of steam to process and recycle the reagent. If the steam is taken from the existing power plant boiler/steam-turbine system, that represents a significant power generation heat cycle change that requires steam path re-design and modification of the generating unit. Once completed, the modifications intrinsically tie together the generating unit with the $CO_2$ capture system. Such a combination of systems has never been demonstrated and must be rigorously tested and optimized before the technology can be deemed reliable, proven, or commercially viable. In addition, the equipment to capture $CO_2$ is large and an entire system capable of treating the effluent of a power plant requires extensive tracts of land. In the AEP/Alstom study of a commercial scale installation, the system was designed to capture 265 MWe worth of flue gas (approximately 1/5 of the plant output), yet it occupied a footprint nearly the same size as the original power plant, or about 11 acres. Size alone precludes deployment of the technology at many existing power plants and must be carefully considered in the design of any new power plant.

AEP also partnered with Battelle to study and validate sequestration of $CO_2$ into deep saline reservoirs near the Mountaineer Plant. Approximately 37,000 metric tons of captured $CO_2$ were compressed and injected into two saline reservoirs located roughly 8,000 feet beneath the plant site. Besides two injection wells, one into each of the reservoirs, AEP deployed three full-depth monitoring wells at various distances from the injection point. Many experimental and novel technologies were tested at the site. The difficult nature of the geology in the area proved some of these technologies to be inappropriate for the application. Again, while the project was successful in injecting and confining all of the $CO_2$ sent to the wellheads, the scale was quite small and far from being representative of what would be required for a full scale deployment. Furthermore, there remains great uncertainty surrounding the liability for and future ownership of injected $CO_2$, which could dissuade any operator from injecting at commercial scale.

In conclusion, it is more accurate to state that the AEP Mountaineer project proves that the technology shows promise for existing or future plant application, but is still many years from being proven at a commercial scale, still requires development of an appropriate regulatory or legal framework, and cannot yet be deemed as commercially viable technology.

### E. EPA's rationale is insufficient for concluding that CCS is a feasible control technology option for coal-based generating units

EPA relies on four factors as the basis for their "position that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available in light of the limited amount of new coal-fired construction expected in the foreseeable future."[99] As discussed below, *none* of the four factors described by EPA demonstrates that CCS is commercially available or feasible as a practical matter. In fact, EPA's rationale actually highlights the significant development steps that CCS must take before it can even begin to be considered a viable control option.

#### i. First EPA basis: The "Technological Feasibility of CCS."[100]

EPA utilizes the findings of President Obama's Interagency Task Force on Carbon Capture and Storage ("Task Force") to assess the current state of CCS technology. The charge of the Task Force was to propose "a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016."[101] The proposed rule notes that the Task Force found that "there are no insurmountable...barriers that prevent CCS from playing a role in reducing GHG emissions." But, as EPA points out, the Task Force also acknowledged that "early CCS projects face economic challenges related to...first-of-a-kind risks" among other factors.[102] In fact, the final report of the Task Force notes that "barriers hamper near-term and long-term demonstration and deployment of CCS technology."[103] In essence, an ambitious near-term research, development, and demonstration program would need to be implemented in order to overcome barriers to the commercialization of CCS. To date, such a program has yet to yield a single operating commercial-scale demonstration project at a coal-based generating unit and is certainly not on pace to achieve the five to ten projects by 2016 that the Task Force recommended for overcoming barriers by 2020.

[99] 77 Fed. Reg. at 22,414.
[100] Id.
[101] Id.
[102] Id.
[103] Report of the Interagency Task Force on Carbon Capture and Storage, p. 14 (Aug 2010).

With respect to carbon capture, EPA notes that other industries have captured $CO_2$ "since the 1930's using a variety of approaches."[104] For EPA to suggest that capture technologies should be readily transferable to coal-based electric generating units because of a long history of use in other industries ignores the multitude of technical, process design, and operational differences between the "industrial gas streams" referenced and a coal-based power plant. It also ignores the significant difference in the quantities and end use of the captured $CO_2$. The quantities of $CO_2$ captured from coal-based generating units will be orders of magnitude greater than that for most "industrial gas streams," while the end use for coal-based $CO_2$ will be for geologic sequestration or enhanced oil recovery processes rather than "to produce food and chemical-grade $CO_2$."[105]

Additionally, EPA notes in the preamble to the proposed rule that pre-combustion, post-combustion, and oxy-combustion systems are technically feasible. While technically feasible, *none* of these capture systems has even been demonstrated at a coal-based power plant on a commercial-scale as either an independent process or, more importantly, as an integrated process with a $CO_2$ utilization or geologic storage system.

EPA notes that "the costs of $CO_2$ capture and compression represent the largest stumbling block to widespread commercialization of CCS."[106] As noted in Section (a) above, EPA's focus on capture costs as the largest barrier is far too narrow and ignores numerous other development risks and barriers to commercial development by minimizing the significant technical challenges that exist for capture system deployment and by overlooking the equally significant technical, cost, and legal challenges with transport and storage systems.

EPA asserts that "the remaining steps for CCS (i.e., pipeline transportation and storage) are well established but less expensive than capture and compression," and that based on the experience of other industries "the transportation component of CCS is not expected to be a significant stumbling block to the commercial availability of CCS."[107] While the U.S. has experience in transporting limited amounts of $CO_2$ via pipeline and has identified *potential* geologic storage reservoirs, the conclusion that this level of development is sufficient to allay any related concerns about CCS commercialization at coal-based generating facilities is overly

[104] Id. at 22,415.
[105] Id.
[106] Id.
[107] Id.

simplistic. Significant development barriers remain for these aspects of the technology. For instance, the DOE's Carbon Sequestration Program plan has four goals that can be summarized as: (i) reducing CCS related costs, (ii) improving assessments of geologic storage, (iii) developing technologies for evaluating the retention of $CO_2$ that has been geologically stored, and (iv) completing a best practices manual for site selection, characterization, site operations, and closure practices. DOE notes that "[o]nly by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020."[108] In summary, EPA's position that the "remaining steps for CCS are well established" ignores the many additional steps required to assure the commercial availability of these technologies for the greatly increased amounts of $CO_2$ generated by coal-based generating units. EPA also simply ignores the fact that much more development is needed to address the multitude of technical, regulatory, legal, financial, and societal barriers associated with widespread deployment of this technology.

In terms of sequestration, EPA cites four projects around the globe that are capturing and geologically storing $CO_2$ to indirectly suggest that the technology is readily available for sources to use in complying with the proposed rule. Although these projects further demonstrate the potential of CCS as a control technology, they are insufficient to address the scope of development barriers that remain for CCS to be commercially acceptable for coal-based generation. This is, in part, because these projects are not being demonstrated at a coal-based power plant, and therefore do not address the related technical challenges associated with process integration, or the significant cost barriers for capture systems. Further, the projects do not address the technical, regulatory, and legal barriers to geologic sequestration that impede the development of commercially available CCS for coal-based power generation.

EPA also identifies various regulatory programs that apply to the geologic storage of $CO_2$, namely the Underground Injection Control Class VI rule, the Greenhouse Gas Reporting Program, and proposed revisions to the RCRA program. EPA notes that "[t]ogether, these actions help create a consistent national framework to ensure the safe and effective deployment of geologic sequestration."[109] These actions are a start, but fall far short of sufficiently resolving the many critical regulatory and legal issues that have been widely recognized as impeding the

[108] Department of Energy / National Energy Technology Lab. Feb 2011. p. 10.
[109] 77 Fed. Reg. at 22,415.

commercialization of CCS. For example, the President's Task Force on CCS concluded that "for widespread cost-effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship" and that "regulatory uncertainty has been widely identified as a barrier to CCS deployment."[110] The National Coal Council has advised the Secretary of Energy that "[t]he management of long-term liability risks is [a] critical consideration for CCS projects...[U]ncertainty regarding long-term liability options remains a challenge."[111] Further, a 2011 study from the Harvard Kennedy School's Energy Technology Innovation Policy Research Group similarly found that, for the commercial-scale CCS demonstration projects in Phase III of the DOE's Regional Carbon Sequestration Partnerships Program, "[l]iability for sequestration of $CO_2$ and lack of coordination among regulatory authorities" would pose "significant barriers."[112]

EPA's position on the feasibility and availability of CCS in the proposed rulemaking are in many ways contradictory to its assessment of the technical feasibility, cost-effectiveness, and commercial availability of CCS in the *PSD and Title V Permitting Guidance for Greenhouse Gases* document. Throughout the guidance document, EPA suggests that CCS be considered in a BACT analysis and that CCS will likely not apply because it is not technically feasible and/or because it is not cost-effective - both reasons highlight the fact that CCS is not commercially available. The examples below from the guidance document indicate that CCS will likely not qualify as BACT. If the level of development is insufficient to generally apply CCS as BACT, it is necessarily also insufficient to support the effective use of CCS as a basis for NSPS.

- "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[113]

- "Based on these [technical, cost, logistical, etc] considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors."[114]

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[110] Report of the Interagency Task Force on Carbon Capture and Storage, pp. 10-14 (Aug 2010).
[111] Expediting CCS Development: Challenges and Opportunities, p. 83 (Mar 2011).
[112] Craig A. Hart, Putting It All Together: The Real World of Fully Integrated CCS Projects, Discussion Paper 2011-06, Belfer Center for Science and International Affairs (June 2011) available at http://belfercenter.ksg.harvard.edu/files/Hart%20Putting%20It%20All%20Together%20DP%20 ETIP%202011%20web.pdf).
[113] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36.
[114] Id.

- "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 [Technical Feasibility Analysis] of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 [Economic, Energy, and Environmental Impacts Analysis] of the BACT analysis, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible."[115]

#### ii. Second EPA basis: "Expected reduction in CCS costs"[116]

The proposed rule states that "DOE/NETL estimates that using today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal plant, and around 35 percent...for a new advanced...IGCC plant."[117] The statement is pulled directly from the 2010 DOE CCS Roadmap report, but it lacks important context from the report that elaborates that CCS is not yet commercially available. For example, the report notes that the DOE RD&D effort "involves pursuing advanced CCS technology...so that full-scale demonstrations can begin by 2020" in order to "enable broader commercial deployment of CCS to begin by 2030." The report also notes that "advanced technologies developed in the CCS RD&D effort need to be tested at full scale....*before* they are ready for commercial deployment."[118] It is clear from the scope of RD&D identified by DOE, that CCS is not commercially available for coal-based generation. Furthermore, the fact that CCS has been estimated to add 80% to the cost of electricity in and of itself speaks to its lack of commercial viability and the infancy of the technology as a potential emissions control option for coal-based generation.

EPA attempts to address the CCS cost issue by equating the development of CCS to the development of other emissions control technologies. The proposed rule notes that "significant reduction in the cost of $CO_2$ capture would be consistent with the overall experience with the cost of pollution control technology." Further, "[r]eductions in the cost of air pollution control technologies...have been observed over the decades. We [EPA] expect that the costs of capture

[115] Id. at. pp 42-43.
[116] 77Fed. Reg. at 22,415.
[117] Id. at 22,415-22,416.
[118] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap, pp. 10-11 (Dec. 2010) (emphasis added).

technology will follow this pattern."[119] In general, the cost and performance of any technology should improve with broader commercial deployment, but as noted in the recent CRS report (*see supra*), the knowledge gained though research, demonstration, and initial operating experience sometimes results in *increased* costs during the development period, and the magnitude and rate of development is not a one-size-fits-all trend.[120]

The scope and complexity of development issues for CCS are dramatically different than for other emission controls such as flue gas desulfurization ("FGD") or selective catalytic reduction ("SCR") technologies. The development challenges of CCS at coal-based power plants are unique due to the greater complexity of process integration, magnitude of operational considerations, and the significant increases to cost of electricity production. CCS for coal-based generation is also very unique with respect to the magnitude of $CO_2$ byproduct that must be handled, transported, and stored in geologic formations. For example, coal-combustion ash and FGD-related solids by-products are solid materials that can be handled and stored in a landfill, while $CO_2$ is generally captured and compressed to a supercritical liquid which must be stored in deep geologic formations, and will be subject to a more extensive, diverse, and in many cases undeveloped set of regulatory and legal requirements. EPA has acknowledged in their guidance document for PSD permitting for greenhouse gases that the scope of design, construction, and operation considerations are much different and unique for CCS compared to other emission control systems by noting:

> "EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage."[121]

Shoehorning the development of CCS technologies into historic developmental and cost reduction curves for existing emission control systems is inappropriate and results in unrealistic

[119] 77Fed. Reg. at 22,416.
[120] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700, at pp. 6, 9 (April 23, 2012).
[121] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

expectations of the performance, timing, and cost of CCS commercialization. EPA references one study by Rubin, et. al that applies this very methodology to predict that based on "typical development curves," $CO_2$ capture costs will be reduced by as much as 26% for coal-based generation "*after* installation of the first 100 GW of capacity."[122] Again, the preamble to the proposed rule does not include important context that is necessary to understand the results. The study itself notes that "there is currently little empirical data to support the assumptions and models used to calculate future $CO_2$ capture costs for power plants," and that "there are no easy or reliable methods...to quantify the magnitude of potential cost *increases* commonly observed during early commercialization." In regards to the methodology applied in the analysis, the study notes that "[o]ne drawback of this approach is that is does not explicitly include potential cost *increases* that may arise when building or combining components that have not yet been proven for the application and/or scale assumed." The study correctly notes that "an important caveat...is to recall that the cost and learning curve estimates in this study do not include the costs of $CO_2$ transport and storage." Also, the authors point out that "a study of this nature...has other important limitations that must be recognized. For one, the concept of a constant learning rate... often...is an over-simplification of actual cost trends for large-scale technologies."[123] Rather than assuming that any *decrease* in the costs associated with CCS at coal-fired generating units will occur during EPA's study period, EPA should be assuming that costs may increase, and could increase dramatically as new information is discovered.

Results of this study fail to provide a definitive assessment of first-of-a-kind ("FOAK") or $N^{th}$-of-a-kind ("NOAK") costs, performance, or risk, and represent, at best, conjecture. To begin, reliable FOAK estimates are difficult to generate in large part because commercial-scale CCS processes on a coal-based power plant have *not* yet been demonstrated. AEP completed a front-end engineering and design estimate for a commercial-scale CCS project at our Mountaineer Plant, which was designed to capture $CO_2$ from approximately 20% (235 MWe) of the combustion gas, was greater than $1 billion.[124] That project was cancelled, but it highlights the fact that first-mover CCS projects will be very expensive and that more reliable cost information for FOAK can only be derived from *operating* commercial-scale CCS demonstration

[122] Id. (emphasis added).
[123] Rubin, E.S., et. al. "Use of experience curves to estimate the future cost of power plants with CO2 capture." International Journal of Greenhouse Gas Control I, pp. 189-196 (2007) (emphasis added).
[124] Final Technical Report, Mountaineer Commercial Scale CCS Project, DE-FE0002673, pp. 7-8 (Dec 8, 2011).

projects at coal-based power plants. Reliable baseline cost, performance information, and lessons learned from FOAK CCS deployments and operation are required before the true scope of development challenges can be identified to support realistic projections for achieving a commercially acceptable NOAK CCS process. In short, accurate FOAK project cost and performance estimates require completion of commercial-scale demonstrations. Beyond that, NOAK project cost and performance estimates require a sound understanding of all aspects of the FOAK project, followed by further research, development, and refinement. Where we stand on that timeline today makes estimates for NOAK systems nothing more than fanciful speculation.

Further, assuming that the results of the Rubin, et al study cited by EPA accurately predict the development of commercial CCS, EPA should consider what the results actually say with respect to the magnitude and timescale of development. First, as noted previously, the study estimates $CO_2$ capture costs will be reduced by as much as 26% for coal-generation "*after* [emphasis added] installation of the first 100 GW of capacity." For context, the authors note that "the nominal value for this study is 100 GW – equivalent to roughly the first 25 years of experience for $NO_x$ and $SO_2$ capture systems at coal-fired power plants."[125] Assuming 600 MW per unit, then 100 GW is equivalent to approximately 170 new coal generating units. Therefore, the study is suggesting that if the commercial development of CCS parallels the development of $NO_x$ and $SO_2$ emission controls, then after 25 years and/or approximately 170 CCS projects, the cost of CCS for coal-based generation "can be expected" to be reduced by as much as 26%. As previously mentioned, the proposed rule estimates that "available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal plant … ." Even with a 26% reduction in capture cost, the impact to the cost of electricity from CCS would preclude it from being commercially acceptable. Therefore, it cannot be concluded from the study referenced by EPA that the cost of $CO_2$ capture for coal-based generation will be sufficiently reduced to enable commercial acceptance of CCS in time to meet the requirements of the proposed NSPS. To the contrary, the study confirms that significant cost and development challenges remain before CCS becomes a commercially viable emission control option.

[125] Rubin, E.S. et. al. p. 192.

### iii. Third EPA basis: "Limited amount of construction of new coal-fired power plants"[126]

EPA estimates that only a few new coal-based power plants will be built by 2020 and that as a result, these projects will have greater access to various financial incentives and funding mechanisms. In no way does this suggest that CCS is feasible as a practical matter or commercially available. Financial incentives are customarily required to support the development of technologies that are not ready for commercial deployment. As discussed previously, significant barriers to commercial acceptance remain that can only begin to be addressed through the deployment of numerous commercial-scale demonstration projects. It is unrealistic to assume that the limited number of new coal plants projected by EPA would shoulder the burden for the industry of overcoming CCS development barriers, while trying to operate as required to justify the investment. In other words, a new coal plant is designed to safely and reliably produce a commercial product – electricity; it would not be designed for the primary purpose of CCS research and development.

### iv. Fourth EPA basis: "State Requirements for CCS"[127]

EPA cites state regulatory programs in Montana and Illinois as indicators of CCS feasibility. These are regulatory programs that limit greenhouse emissions, not affirmations that CCS is feasible as a practical matter or commercially acceptable. In fact, no commercial-scale CCS projects on a coal-based generating unit are operating in either state, and none has been identified that is currently under construction.

EPA also references operating or planned $CO_2$ capture processes. The systems in operation provide $CO_2$ to the food processing industry and to a soda ash plant. Another is a synthetic natural gas plant that provides $CO_2$ for enhanced oil recovery. The AEP Mountaineer CCS project is referenced, but as noted previously, this was not a commercial-scale project. Only one of the four remaining planned projects identified was at commercial scale.

These examples point to the potential of CCS for coal-based power plant operations and to the ongoing efforts to development of the technology. However, the information presented by

[126] 77 Fed. Reg, at 22,416.
[127] Id.

EPA does not indicate that commercially available CCS technology is a viable emission control option for meeting the proposed NSPS requirements.

## VI. Response to Technical Questions For Which EPA Requested Comments

In the proposed rule, EPA requested comment on several technical issues. Responses to those requests are provided below:

### A. Use of gross-based output limits[128]

EPA requested comment on the use of gross-based output standards. Earlier this year in the NSPS for Subpart Da conventional emissions EPA did not require a net output approach "[d]ue to the lack of net-output-based emission rates for multiple type of EGUs with various control configurations over a range of operating conditions."[129] EPA should be consistent in the use of gross-based output standards in this rulemaking. However, the use of gross-based generation results in a number of complex technical and operational considerations that can influence emission rates and unit efficiencies. These issues warrant a much greater technical analysis, which further supports that finalization of these standards is premature and that the proposed rule should be changed to an advanced notice of proposed rulemaking so that the agency can fully evaluate the implications and design of gross-based output standards.

### B. Adequacy of the proposed 1,000 lb/MWh NSPS[130]

EPA requested comment on whether the proposed standard of 1,000 lb/MWh should more appropriately be set within the range of 950 and 1,100 lb/MWh.[131] Based on the lack of commercially available $CO_2$ control technologies for fossil-fired generation and expected higher capacity factors of new natural gas combined cycle ("NGCC") units compared to historic operations, it is recommended that a more appropriate standard for new NGCC units is 1,100 lb/MWh or more. A separate standard specific to new coal units should be established that reflects the best demonstrated performance of existing advanced coal technologies.

[128] Id. at 22,416.
[129] 73 Fed. Reg. 33642 at 4.
[130] 77 Fed, Reg, at 22,414.
[131] Id.

### C. CCS as the best system of emission reductions

The proposed rule states that "[a]lthough we [EPA] are not proposing that CCS, including the 30-year averaging compliance option, does or does not qualify as the BSER adequately demonstrate, we also solicit comment on that issue."[132] As shown by the technical comments of CCS above, CCS clearly does not qualify as the Best System of Emission Reductions within the meaning of section 111(a) of the Clean Air Act.

### D. Coal refuse[133]

EPA solicits comments on developing a subcategory for electric generating units that burn over 75% coal refuse on an annual basis. AEP supports EPA's proposed subcategory that would exempt such units from the proposed NSPS requirements. Further, AEP supports additional fuel-specific subcategorization that establishes a coal-specific standard that reflects the best demonstrated performance of existing advanced coal technologies.

### E. Combined heat and power[134]

The proposed rule states that EPA is "also considering and requesting comment on if exempting all CHP facilities where useful thermal output accounts for at least 20 percent of the total useful output from this proposed rule." AEP supports an EPA's proposed exemption for such facilities.

### F. Stationary simple cycle turbines[135]

EPA requests comments on the exemption of stationary simple cycle turbines from the proposed rule. AEP supports EPA's proposed exemption for such facilities. Additionally, in the case where simple cycle turbines are constructed with the intent to operate prior to the future construction of a heat recovery steam generator (HRSG), such turbines should be exempted from the proposed rule until such time that construction of the HRSG and related equipment is completed and the unit commences operation in a combined cycle mode.

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[132] Id. at 22,420.
[133] Id. at 22,431.
[134] Id.
[135] Id. at 22,431-22,432.

## VII. Conclusion

For all of the foregoing reasons, EPA's proposed NSPS for the new category of fossil fuel-fired electric generating units created specifically in Subpart TTTT is fatally flawed and should be withdrawn. If EPA chooses to proceed with the current rulemaking, such substantial additional information and analysis is required that a new proposed rule must be issued. Therefore, an alternative might be to issue a notice that the current proposal will be deemed an advance notice of proposed rulemaking, have no immediate effect, and to solicit information necessary to determine the "best system of emission reduction" that is adequately demonstrated for the existing source categories in Part 60. In particular, the following issues must be addressed before establishing a legitimate standard of performance for GHG emissions from EGUs.

### A. Fuel-specific standards should be established in lieu of a one-size-fits-all approach that effectively requires one fuel (coal), but not another (natural gas) to use an undeveloped control technology

If EPA chooses to move forward with this rulemaking, then EPA's recognition of the fundamental differences between natural gas and coal infrastructure and markets, and between gas-fired generation technologies and coal-fired generation technologies, requires the two source categories to remain separate for purposes of category-appropriate Section 111 performance standards for GHGs. Alternatively, EPA could create separate source subcategories with subcategory-appropriate GHG performance standards. Regardless, EPA's proposed performance standard is supported only for, and should be limited to only, the source category or subcategory of NGCC EGUs. EPA recognizes that no existing technology has been deployed that would allow coal-based EGU's to meet the same standard. Integrated gasification combined cycle (IGCC) units should be maintained in a separate category or subcategory. There are currently only two operating IGCC units in the United States, and separate greenhouse gas performance standards are needed for this unique emerging technology.

Moreover, based on the factual errors identified above, EPA needs to undertake additional analyses to accurately describe both the costs and benefits of this rule. Should the direct benefits of the rule not greatly exceed the costs, EPA should pull the rule entirely, and propose a standard that can be achieved using commercially available technologies at a reasonable cost. EPA must:

1. Quantify the costs of the rule using at least a 30-year time horizon.
2. Analyze the regional differences in fuel supply that may alter new generation economics and lead to additional costs associated with this national standard.
3. Include other modeling scenarios which explore other factors that may influence natural gas prices that reflect the range of pricing and price spreads between coal and gas experienced in the past decade, and that may plausibly occur in the long term future.
4. Rerun IPM with revised capital costs for new NGCC and PC units.
5. Recalculate the levelized cost of electricity using more plausible capacity factors for new natural gas combined cycle units.
6. Remove from the RIA speculative dialogue on the Societal Cost of Carbon and health benefits, as the numbers presented are overly speculative and arbitrary.

EPA has applied a double-standard, rationalizing the need for greenhouse gas emission reductions and the availability of CCS as it relates to coal-based generation, and ignoring its potential applicability to natural gas combined cycle generating units. EPA claims in the proposed rule that "[H]uman-induced climate change has the potential to be far-reaching and multidimensional," and that climate change "threatens public health," "is expected to have numerous effects on public welfare," "threaten[s] energy, transportation, and water resource infrastructure," and "will fundamentally rearrange U.S. ecosystems."[136] Further, the agency expresses an urgency to address these impacts by stating that "the environmental, economic, and humanitarian risks of climate change indicate a pressing need for substantial action" and that "[e]ach additional ton of greenhouse gases emitted commits us to further change and greater risks."[137]

To address these issues, EPA proposes a standard of 1,000 lb/MWh "based on the performance of widely used natural gas combined cycle (NGCC) technology."[138] The proposed limit is intended to have minimal, if any, impacts on the design, cost, operations, or prospects for new NGCC units, but will significantly impact, if not effectively eliminate the development of

[136] 77 Fed. Reg. 22402
[137] Id. 22395 (citation omitted).
[138] Id. 22392

new coal units unless $CO_2$ control technologies become commercially available. EPA downplays this concern by noting that "[c]apture of $CO_2$ from industrial gas streams has occurred since the 1930s..." The agency concludes that "the costs of $CO_2$ capture and compression represent the largest stumbling block to widespread commercialization of CCS," but that "significant reductions in the cost of $CO_2$ capture" are expected. To support this claim, EPA cites a study that estimates capture costs will decline by 40% for NGCC units and by up to 26% for coal-based generating units.[139] Based on these references and other information, EPA concludes that CCS is an available control option for coal-based generation. Yet, despite referencing that $CO_2$ capture has been used in the natural gas industry, and presenting estimates that capture costs will drop more significantly for NGCC than for coal, EPA does not require NGCC developers to use this undeveloped emission control technology. In fact, EPA is silent as to why CCS is or is not equally applicable to NGCC.

By 2020, EPA estimates that nearly 25 GW of new NGCC capacity will be developed, and that no new coal units beyond those already on the books will be constructed.[140] Based on conservative estimates, potential $CO_2$ emissions from this new natural gas capacity alone would be over 90 million tonnes per year.[141] EPA notes that "under a wide range of future market conditions, this proposed EGU GHG NSPS is not expected to change GHG emissions for newly constructed EGUs."[142]

But if the magnitude of climate change impacts are as severe as EPA has stated; if the significance of these risks requires immediate reductions of GHG emissions; and if EPA's logic for determining that CCS is available for coal-based generation is equally applicable to NGCC, then why doesn't EPA require NGCC units to use CCS to reduce the potential 90 million tonnes of new $CO_2$ emissions from these sources as well? The answer is two-fold. One, as noted in prior sections, CCS is *not* commercially available for coal-based generation or NGCC units. Moreover, the development of CCS for *any* EGU faces significant technical, financial, and legal barriers. And two, the proposed rule, according to EPA "does encourage the current trend towards cleaner generation" and "will send a strong signal both domestically and internationally..... to consider less GHG-intensive forms of power generation." In other words,

[139] Id. 22415-22416
[140] Proposed EGU GHG NSPS. Regulatory Impact Analysis. Mar 2012. p. 5-14.
[141] Calculation: (24.8 GW new NGCC) * (950 lb $CO_2$/MWh) * (1 tonne / 2204.6 lb) *(1000 MW/GW) *(8760 hr/yr) = 93,615,894 tonnes/yr
[142] Proposed EGU GHG NSPS. Regulatory Impact Analysis. Mar 2012. p. 5-1.

the proposed rule supports a policy that effectively eliminates new coal-based power generation - that is not the purpose of the NSPS regulatory program.

The purpose of the NSPS regulatory program is to establish a standard of performance that "reflects the degree of emission limitation achievable through the application of the best system of emission reduction."[143] NSPS is not an appropriate vehicle for establishing a domestic energy policy that effectively restricts fuel choices and technologies by requiring only certain sources to employ control technologies that are not commercially available and are not expected to be available for many years. EPA should establish fuel-specific NSPS that represent a standard of performance that has been demonstrated to be achievable with commercially available control technologies.

**B. EPA should not base a standard on technology that is not commercially available, but if EPA insists on promulgating a standard based on projected future technology developments, the long-term average limit should be revised to align with a more realistic CCS development timeline**

As discussed in the prior sections, commercial CCS technology is not currently available for coal-based generation, and is not expected to be commercially available within the next decade. In proposing the 30-year average option, EPA is essentially acknowledging that the significant development of CCS technology remains and that at least ten years (the point in time when a more stringent limit becomes applicable) is needed for that development. Instead of requiring a new coal-based unit to achieve an emission limit that, in essence, mandates the immediate use of a technology that is not commercially available (option one: annual limit), or an emission rate that is premised on the hope of technology development (option two: 30-year limit), EPA should establish a coal-specific limit based on the performance of operating advanced coal generation processes. As noted above, EPA may not establish standards "solely on the basis of ...'crystal ball inquiry.'"[144] Accordingly, the proposed standard should be revised, the existing separate source categories should be retained, and different standards should apply to NGCC units and the various fuel-based subcategories of steam EGUs.

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[143] Clean Air Act. Section 111(a)(1)
[144] Essex Chem. Corp. v. Ruckelshaus, 486 F.2d at 433.

However, if EPA decides to retain the option for a longer-term average, the duration of the average should be increased to a 40- or 50-year average. This would recognize that CCS for coal-based generation is currently not commercially available and, at the current pace of development, will not be viable in the next decade. The time period also approximates the 2050 date by which President Obama set a goal of reducing greenhouse gas emissions in the United States by 83 percent. EPA could revisit the efficacy of the long-term average in context with the state of CCS development during the required 8-year NSPS review cycle.

The long-term limit also should be designed so that applicable limits during the non-CCS phase of operations (which in the proposed rule would be ten years) accurately reflect the best demonstrated emission rate achieved by operating advanced coal technologies. The current assumed rate of 1,800 lb/MWh should be revisited. AEP is currently constructing an ultra-supercritical unit, which is employing state-of-the-art advanced coal technology. Even this unit would not be able to reliably achieve an 1,800 lb/MWh rate, and it will be the only unit in the United States with such an advanced steam cycle. Based on the subbituminous fuel used and the projections for load fluctuation and periodic unit startups, AEP estimates an annual gross $CO_2$ emission rate closer to 1,900 lb/MWh.

Further, the proposed 10-year threshold for becoming subject to a lower emission limit is too stringent and does not parallel the expected timeframe for when CCS will be commercially acceptable. In context with the above comments regarding the need for a longer overall averaging period (40-50 year average), it is recommended that a lower emission limit not become effective until year 21 of the long-term average.

### C. EPA should either withdraw its proposed rule or convert it to an advance notice of proposed rulemaking, and continue gathering information

EPA’s proposed Subpart TTTT has many of the characteristics of an advance notice of proposed rulemaking. EPA has acknowledged that it lacks sufficient information to propose greenhouse gas NSPS for modified and reconstructed electric utility generating units or for electric utility generating units located outside the continental United States. Yet, EPA's lack of adequate information to set EGU GHG performance standards for modifications, reconstructions, and units located outside the continental United States is no greater than its lack of information to set GHG performance standards for new coal-fired electric generating units. EPA's information on CCS, moreover, is incomplete, flawed, and insufficient for the standard proposed. And, there is an important legal difference between a proposed performance standard and an advanced notice of proposed rulemaking – the applicability trigger date is the date of proposed rulemaking under Clean Air Act § 111(a).[145] Thus, failure to withdraw these proposed rules would set a de facto GHG standard that is not realistically achievable for coal-fired EGUs.

Based on the legal concerns described above, EPA must withdraw its proposed Subpart TTTT or convert it to an advance notice of proposed rulemaking. EPA may then properly determine **separate** greenhouse gas new source performance standards for stationary sources that are subject to Subpart Da and for natural gas combined cycle systems in Subpart KKKK. Such a revision of Subparts Da and KKKK would be unnecessary, pursuant to the "efficacy" principle of Section 111(b)(1)(B) of the Clean Air Act. According to statute, the Administrator need not review and revise any new source performance standard "if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard."[146] Here, revising Subpart Da would not be efficacious because EPA projects that no new coal-fired electric generating units will be subject to the proposed standard before 2020 anyway.[147] Moreover, the obligation to install Best Available Control Technology for greenhouse gases under the Tailoring Rule obviates the need for, and benefits of, a GHG performance standard for new coal-fired electric generating units. Thus, revising Subpart Da now would be no more efficacious than waiting to obtain more information before regulating $CO_2$ emissions from new coal-fired electric utility generating units.

[145] See 42 U.S.C. § 7411(a)(2) (defining "new source" to include any stationary source constructed "after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance . . . which will be applicable to such source.").
[146] 42 U.S.C. § 7411(b)(1)(B).
[147] See 77 Fed. Reg. at 22,398-99.

## Appendix A - Assessments of the State of CCS Development for Coal-Based Electric Generation

| Organization | Date | State of CCS | Barriers to Commercially Acceptable CCS | Prospects for CCS Development |
|---|---|---|---|---|
| President Obama's Interagency Task Force on Carbon Capture and Storage. Report of the Interagency Task Force[148] | Aug. 2010 | "Current technologies could be used to capture $CO_2$ from new and existing fossil energy power plants; however, they are not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application." (p.50)<br><br>"CCS technologies...are not likely to be widely deployed at coal-fired power plants....without additional knowledge generated by research, development, and demonstration activities." (p.87) | "Though CCS technologies exist, "scaling up" these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges." (p.9)<br><br>"..barriers hamper near-term and long-term demonstration and deployment of CCS technology." (p.14)<br><br>"A concerted effort to properly address financial, economic, technological, legal, institutional, and social barriers will enable CCS to be a viable climate change mitigation option..." (p.8) | "Administration analyses of proposed climate change legislation suggest that CCS technologies will not be widely deployed in the next two decades..." (p.8)<br><br>"The focus of CCS RD&D is....to facilitate widespread cost-effective deployment after 2020." (p.9) |
| The National Coal Council (a Federal Advisory Committee to Secretary of Energy Chu). *Expedited CCS Development: Challenges & Opportunities*[149] | Mar. 2011 | "..a range of issues must be addressed before CCS processes are commercially acceptable for coal-based electric generating units. ...key development concerns include the fact that commercial-scale CCS processes have *not yet* been demonstrated on a coal-fired generating unit" (p.1) | "...the current CCS demonstration program in the [U.S.]...is not on pace to significantly advance CCS development in the near-term due to technical and equally non-technical obstacles.... Challenges to CCS development...can be broadly categorized into technical, financial, and regulatory areas." (p.1) | "At the current [development] rate, CCS technologies will continue to be in an early development stage by 2020." (p.64)<br><br>"Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050." (p.14) |
| DOE / NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update[150] | May 2011 | "...in their current state of development [the $CO_2$ capture technologies being used in industrial applications] are not ready for implementation on coal-based power plants" (p.4) | "[$CO_2$ capture] technologies are not ready for implementation on coal-based power plants [because] (1) they have not been demonstrated at the larger scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support $CO_2$ capture would decrease power generating capacity...; and (3) if successfully scaled-up, they would not be cost effective at their current level of process development." (p.4) | "It is anticipated that successful progression from laboratory- to full-scale demonstration will result in several of these [$CO_2$ capture] technologies being available for commercial deployment by 2030." (p.10) |
| DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap[151] | Dec. 2010 | "...cost-effective and efficient CCS technologies will need to be developed and demonstrated at full-scale prior to their availability for widespread commercial deployment." p. 5<br><br>"...at their current state of development these [$CO_2$ capture] technologies are not ready for implementation on coal-based power plants." (p.21) | "...advanced technologies developed in the CCS RD&D effort need to be tested at full scale in an integrated facility before they are ready for commercial deployment." (p.11) | "....the overall timeline for RD&D....involves pursuing advanced CCS technology from the fundamental / applied stage through pilot-scale so that full-scale demonstrations can begin by 2020. The RD&D effort will produce the data and knowledge needed to establish the technology base, reduce implementation risks by industry, and enable broader commercial deployment of CCS to begin by 2030." (p.10) |
| DOE / NETL Carbon Sequestration Program: Technology Program Plan[152] | Feb. 2011 | "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020." (p. 10) | "To accomplish widespread [commercial] deployment [of CCS by 2020], four program goals have been established:<br>(1) [reduce CCS related costs];<br>(2) [improve the] ability to predict $CO_2$ [geologic] storage capacity;<br>(3) develop technologies to demonstrate that...$CO_2$ remains in the injection zones;<br>(4) complete Best Practices Manuals...for site selection, characterization, site operations, and closure practices." (p. 10) | "Only by accomplishing these goals [of the DOE Carbon Sequestration Program] will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades." (p.10) |

[148] "Report of the Interagency Task Force on Carbon Capture and Storage." Aug 2010. www.fe.doe.gov/programs/sequestration/ccs_task_force.html
[149] "Expediting CCS Development: Challenges and Opportunities." Mar 2011. Library of Congress Catalog #2011926623. www.nationalcoalcouncil.org
[150] Department of Energy / National Energy Technology Lab. May 2011. www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/
[151] Department of Energy / National Energy Technology Lab. Dec 2010. www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[152] Department of Energy / National Energy Technology Lab. Feb 2011. www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf

## Appendix E

## Supplemental AEP Comments on the 2012 Proposed NSPS for New Sources

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**ATTN: Docket ID No. EPA-HQ-OAR-2011-0660**

**Re: Supplemental Comments on Proposed Rule to Set Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units**

American Electric Power (AEP) is submitting the following supplemental comments to the Environmental Protection Agency (EPA or Agency) as it develops a revised proposal to set a new source performance standard (NSPS) for carbon dioxide ($CO_2$) emissions from fossil-fueled electric generating units (EGUs) under section 111 of the Clean Air Act (CAA or the Act).[1] The agency's initial proposal, published in April 2012,[2] would have adopted a single standard for a combined source category including solid, liquid, and gaseous fossil fuel fired electric generating units, but the stringency of the standard would have effectively banned the construction of any new units other than highly efficient combined cycle natural gas fired units.

On June 25, the President announced his "Climate Action Plan," a series of executive actions designed to reduce carbon emissions in the U.S., prepare for the impacts of climate change, and emerge as a leader in international discussions. The accompanying Presidential Memorandum directed EPA to issue a revised proposal no later than September 20, 2013, for new sources, and to undertake the development of a proposal for modified, reconstructed, and existing sources that would be issued by June 1, 2014, and finalized by June 1, 2015. As part of the development process, the agency was instructed to directly engage with States, tribal leaders, leaders in the power sector, labor leaders, non-governmental organizations, and other experts on issues that would inform the design of the program, specifically focusing on ways to reduce costs, ensure that the standards enable continued reliance on a range of energy sources and technologies, and allow for the continued provision of reliable and affordable electric power. The memorandum expressly

[1] *Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generation Units*, 77 Fed. Reg. 22,392 (April 13, 2012).
[2] *Id.*

states that it is not intended to impair or otherwise affect the authority granted by law to any department, agency, or the head thereof.

The primary purpose of these supplemental comments is to clarify and further explain the limits on EPA's authority to adopt a $CO_2$ performance standard for new fossil fuel-fired EGUs under section 111(b) of the Clean Air Act, and why a standard that effectively bans the use of coal, the most dominant energy resource in America, for the generation of electricity exceeds the limits of EPA's authority.

It is critical for EPA to distinguish between the narrow authority granted to the agency under the Clean Air Act, and the traditional states sovereign powers related to such matters as the regulation of electricity that are reserved to the states under the Tenth Amendment to the U.S. Constitution. The structure of the Clean Air Act deliberately confines EPA's authority to the areas in which its expertise is greatest: the evaluation of technologies to reduce or eliminate emissions; the applicability of those technologies to various classes and categories of sources; the cost of employing such technologies; and the energy and non-air environmental impacts associated with the use of those technologies. By contrast, well-established Supreme Court precedent clearly bars EPA from overriding or infringing upon a traditional state sovereign function unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes the agency to do so. As discussed below, neither section 111 nor any other provision of the Clean Air Act contains any explicit authority for EPA to usurp the role of the states in evaluating the mix of options used to generate electricity, authorizing the addition of specific new generation resources, or siting new generation resources within the state. This lack of express authority confirms Congress' intent to respect and preserve the states' historic role in the regulation of electricity, and confirms that EPA lacks the authority to adopt a $CO_2$ standard that effectively bans the use of coal for new electricity generation units.

This clear limitation of EPA's authority is equally applicable to the second rulemaking EPA has been directed to initiate for modified, reconstructed, and existing sources under sections 111(b) and (d) of the Clean Air Act. For the same reasons discussed herein, this limitation requires the agency to respect and preserve state sovereign powers over matters relating to electricity generation, such as determining the appropriate mix of generating resources within a state.

AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S. and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a roughly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power Company (in Virginia, West Virginia and Tennessee), Indiana Michigan Power Company, Kentucky Power Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

## I. OVERVIEW OF AEP'S SUPPLEMENTAL COMMENTS

### A. Legal Flaws of EPA's Proposed $CO_2$ NSPS

On April 13, 2012, EPA proposed to establish a NSPS limit of 1,000 pounds of $CO_2$ per megawatt-hour (MWh) of electricity generated on a gross basis and averaged over a 12-month annual period.[3] This $CO_2$ emissions limit applies (with certain limited exceptions)[4] to each new fossil-fueled EGU that commences construction after April 13, 2012, and that has "a base load rating of more than 73 megawatts ... heat input of fossil fuel."[5] According to EPA, the proposed 1,000 pounds/MWh $CO_2$ limit is "based on the performance of widely used natural gas combined cycle (NGCC) technology" without requiring any further $CO_2$ emissions controls on such gas-fueled units.[6] By contrast, a new coal-fueled EGU can comply with the proposed $CO_2$ limit only through the use of carbon capture and storage (CCS) technology – a technology that EPA has determined is not adequately demonstrated or available on a commercial scale today.[7] The EPA proposal attempts to bridge this technology gap for coal-fueled power plants by establishing an alternative 30-year averaging compliance option for new coal-fueled EGUs that is intended to provide additional time for the demonstration and deployment of the CCS technology on any new unit subject to the proposed $CO_2$ NSPS limit.[8]

AEP submitted detailed comments on EPA's proposed NSPS rule on June 25, 2012. These comments identified the many legal, policy, and technical flaws in the EPA proposal and explained why these flaws leave EPA with no choice but to withdraw the $CO_2$ NSPS proposal in its entirety. Notable flaws identified in AEP's June 25th comments include the following:

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[3] *See* proposed 40 C.F.R. § 60.5520(a), as set forth in 77 Fed. Reg. at 22,436.
[4] The EPA proposal would exempt from the proposed $CO_2$ NSPS three minor categories of steam electric generating units, including those units under development that meet the criteria established for "transitional sources." *See* 40 C.F.R. § 60.5510(b), as set forth in 770 Fed. Reg. at 22,436.
[5] *See* proposed 40 C.F.R. § 60.5509, as set forth in 77 Fed. Reg. at 22,436.
[6] 77 Fed. Reg. at 22,392.
[7] In the preamble to the proposed NSPS rule, EPA specifically declined to select CCS as the "'best system of emissions reduction' that 'has been adequately demonstrated' for new coal-fired power plants." 77 Fed. Reg. at 22,411. In addition, the Agency determined in a 2010 Interagency Task Force report that CCS technologies "are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application." Report of the Interagency Task Force on Carbon Capture and Storage, August, 2010.
[8] *See* proposed 40 C.F.R. § 60.5520(b), as set forth in 77 Fed. Reg. at 22,436.

- The NSPS proposal violates the CAA because it sets a $CO_2$ performance standard based on a technology that is not "adequately demonstrated" and not "achievable" for all power plants within the electric power source category. The CAA requires EPA to adopt a $CO_2$ performance standard that is "adequately demonstrated" and "achievable" for all sources within a particular source category.[9] In the NSPS proposal, EPA is proposing a single uniform $CO_2$ performance standard that is achievable only by natural gas combined cycle units. The standard is infeasible for coal-fueled power plants because CCS technologies, the only option for coal-fueled plants to meet the standard, are not adequately demonstrated or available on a commercial scale today.

- Providing a 30-year averaging period as an alternative compliance option for new coal-fueled power plants does not cure this legal flaw. EPA's standards must be based on technologies that are demonstrated today, not technologies that may be available in the future. Moreover, such an alternative is not a realistic solution to bridging the technology gap for meeting the proposed $CO_2$ performance standard. Neither developers nor lending institutions will be willing to make a multi-billion dollar investment in a new coal-fueled plant unless and until they can secure adequate assurances that a CCS technology capable of achieving the $CO_2$ performance standard can be installed and operated reliably within the initial ten-year period.

- The NSPS proposal is unlawful because it mandates the use of a particular technology. The CAA clearly states that EPA is not authorized "to require ... any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[10] Yet, this is what EPA has done by proposing a 1,000 lb/MWh standard for all fossil-fueled power plants. No adequately demonstrated technology makes it possible for coal-fueled power plants to comply because the only feasible means of complying with the proposed performance standard is through the use of natural gas combined cycle technology. EPA's proposal is a mandate for the construction of new gas-fired generation, and a ban on construction of new coal-fueled plants.

### B. Additional legal reasons why EPA lacks authority to finalize the proposed $CO_2$ NSPS

The purpose of these supplemental comments is to highlight an additional fundamental principle of statutory construction that both informs and limits the exercise of EPA's authority under section 111 of the CAA. This principle of statutory construction derives from the historic role of the states in regulating the generation of electricity, and from the constitutional underpinnings of American federalism. This principle further underscores

[9] Section 111(a)(1) of the Clean Air Act (defining "standard of performance").
[10] Section 111(b)(5) of the Clean Air Act.

EPA's lack of authority to adopt a $CO_2$ performance standard that could interfere with or infringe on state regulation of electricity generation by effectively banning the construction of any new coal-fueled EGUs. For these reasons, AEP continues to believe the proposed rule to set a $CO_2$ NSPS for power plants is legally deficient and, as a result, the Agency has little choice but to withdraw its NSPS proposal in its entirety.[11]

As discussed below in greater detail, it is a well-established rule of statutory construction that EPA cannot rely on a broad delegation of authority to regulate air emissions to override a traditional and fundamental state sovereign function reserved to the states under the tenth amendment of the Constitution. This rule of construction clearly bars EPA from using a general delegation of authority under CAA section 111(b) to adopt a $CO_2$ performance standard that effectively bans the construction of new coal-fired EGUs. EPA lacks the authority to adopt such a fuel-discriminatory performance standard unless Congress makes its intention "so 'unmistakably clear' in the language of the statute" that EPA can override states' long-standing traditional powers to regulate matters pertaining to the generation of electricity.[12]

A review of the relevant provisions of Act reveals that Congress has not adopted such unmistakably clear statutory language to ban coal use, or otherwise regulate the generation of electricity under section 111(b) or any other provision of the CAA. Furthermore, Congress' failure to do so provides further confirmation that EPA lacks the authority to adopt a $CO_2$ performance that would effectively override a traditional and fundamental sovereign function of the states.

## II. FEDERAL AGENCIES MAY NOT OVERRIDE OR INFRINGE ON TRADITIONAL STATE SOVEREIGN POWERS UNLESS EXPRESSLY AUTHORIZED TO DO SO.

Well-established court precedent clearly bars a federal agency from overriding or infringing upon a traditional state sovereign power unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes the agency to do so.

One leading Supreme Court decision that concisely enunciates this fundamental principle of statutory construction is *Will v. Michigan Department of State Police*.[13] In *Will*, the Supreme Court describes this principle as an "ordinary rule of statutory construction that

[11] The Utility Air Regulatory Group (UARG), a not-for-profit association of individual electric generating companies and national trade associations of which AEP is a member, submitted supplemental comments to the docket for this rulemaking on May 16, 2013, responding to two notice of intent to sue letters that had been sent to the Agency with regard to this rulemaking. As UARG noted in that letter, because the one-year deadline for taking final action on the proposed rule has passed, the proposed rule has terminated and formal withdrawal of the rule is not necessary. Nevertheless, formal withdrawal of the April 2012 proposed rule by EPA would benefit the public, particularly in light of the direction EPA has been given to issue a new proposal, so as to avoid confusion regarding the April proposal's legal effect.

[12] *Will v. Michigan Department of State Police*, 491 U.S. 58 (1989).

[13] 491 U.S. 58 (1989). *See* also *Altria Group, Inc. v. Good*, 555 U.S. 70, 77 (2008) (providing a concise summation of the fundamental principle of statutory construction that was articulated in *Will*).

if Congress intends to alter the 'usual constitutional balance between the States and the Federal Government,' it must make its intention to do so 'unmistakably clear in the language of the statute.'"[14] The Court goes on to state that "Congress should make its intention 'clear and manifest' if it intends to pre-empt the historic powers of the States"[15] and that "'the requirement of clear statement assures that the legislature has in fact faced, and intended to bring into issue, the critical matters involved in the judicial decision.'"[16]

The principle has been applied in cases across a broad spectrum of federal legislation. One notable case is *Rapanos v. United States*, [17] in which the Supreme Court affirmed the clear limitations placed on a federal environmental agency's authority to intrude or infringe upon traditional state sovereign powers. In *Rapanos*, the U.S. Army Corps of Engineers (Corps) broadly interpreted the phrase "waters of the United States" to include "ephemeral streams," "drainage ditches," and other structures or channels that are "typically dry" or "have little flow in a year."[18] In rejecting this expansive reading of an admittedly ambiguous statutory phrase, the Supreme Court ruled that the Corps' interpretation would "result in a significant infringement of the States' traditional and primary power over land and water use" and that such regulation "is a quintessential state and local power."[19] Furthermore, the Court stressed that the Corps' efforts to expand its jurisdictional authority over wetlands would allow "the Corps to function as a *de facto* regulator of immense stretches of intrastate land – an authority the agency has shown its willingness to exercise with the scope of discretion that would befit a local zoning board." Finally, in summing up its rationale for invalidating the Corps' regulation, the Court underscored: "We ordinarily expect a 'clear and manifest' statement from Congress to authorize an unprecedented intrusion into traditional state authority. The phrase 'the waters of the United States' hardly qualifies."[20]

Other cases abound in which the Supreme Court has insisted upon an "unmistakably clear" statement from Congress before it will affirm a federal agency's authority to override or infringe on a traditional state sovereign power. Among them is *Solid Waste Agency of Northern Cook County v. United States Army Corps of Engineers* (*SWANCC*),[21] a case in which the Supreme Court held that Army Corps of Engineers cannot exercise federal jurisdiction over isolated ponds and mudflats used by migratory birds because it would result in a significant impingement of states' traditional and primary power over land and

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[14] *Will*, 491 U.S. at 65 (citing *Atascadero State Hospital v. Scanlon*, 473 U.S. 234, 242 (1985) and *Pennhurst State School and Hospital v. Halderman*, 465 U.S. 89, 99 (1984)).
[15] *Will*, 491 U.S. at 65 (citing *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218 (1947)).
[16] *Will*, 491 U.S. at 65 (citing *United States v. Bass*, 404 U.S. 336, 349 (1971)).
[17] 547 U.S. 715 (2006) (plurality opinion). Significantly, Justice Kennedy's concurring opinion in *Rapanos* accepted the "clear and manifest" principle as stated in the plurality's decision, but disagreed with the need for the application of the principle in *Rapanos* due to the statutory limitations placed on the Corps' authority by the phrase "navigable waters." 547 U.S. at 776.
[18] 547 U.S. at 725, 727.
[19] 547 U.S. at 738.
[20] 547 U.S. at 738 (citing *BFP v. Resolution Trust Corporation,* 511 U.S. 531, 544 (1994).
[21] 531 U.S. 159 (2001)

water use without a clear legislative authorization for such impingement.[22] In so ruling, the Court emphasized that the Corps was not entitled to any "*Chevron* deference" in those situations "where the administrative interpretation alters the federal-state framework by permitting federal encroachment upon a traditional state power" – such as, in the case of *SWANCC*, the federal environmental regulation of matters pertaining to "land and water use."[23]

## III. The regulation of electricity generation is a traditional state sovereign power that courts have respected and preserved.

Courts have recognized the regulation of electricity generation as a quintessential state sovereign function that federal agencies have a legal obligation to respect and preserve unless Congress has otherwise made its intentions clear and manifest. This perspective was clearly articulated by the Supreme Court in *Pacific Gas & Electric v. State Energy Resource Conservation & Development Commission*,[24] a case in which the Court ruled that state laws requiring new nuclear power plants to have adequate storage capacity for spent nuclear fuel are not preempted by the Atomic Energy Act of 1954. In so ruling, the Court stated:

> Need for new power facilities, their economic feasibility, and rates and services are areas that have been characteristically governed by the States. ... With the exception of the broad authority of the Federal Power Commission, now the Federal Energy Regulatory Commission, over the need for and pricing of electrical power transmitted in interstate commerce, ... these economic aspects of electrical generation have been regulated for

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[22] *SWANCC*, 531 U.S. at 174

[23] In addition, there are many other instances in which courts have insisted upon an unmistakably clear statement from Congress before the court will affirm that a federal agency has authority to override or infringe on traditional state sovereign power. One such example is *Will v. Michigan,* in which the Court held that the term "person" in a civil rights law does not include the States acting in their sovereign capacity. 491 U.S. 58, 65 (1989). Another notable example is *Nixon v. Missouri Municipal League*, in which the Supreme Court invoked its "working assumption that federal legislation threatening to trench on the States' arrangements for conducting their own governments should be treated with great skepticism, and read in a way that preserves a State's chosen disposition of its own power, in the absence of [a] plain statement [of congressional intent]" and that "[t]he want of any 'unmistakably clear' statement to that effect ... is grounds for the Court's ruling to respect states' sovereign powers on these telecommunication matters." 541 U.S. 125, 140-41 (2004). A third example is *Gregory v Ashcroft*, in which the Supreme Court rejected efforts to interpret broadly a federal age discrimination law that generally prohibits states from discharging employees over 40 years old due to their age. 501 U.S. 452, 466-67 (1991). In so doing, the Court emphasized that it would be inappropriate to extend this federal prohibition to state judges given that the qualification requirement for judges "is a decision of the most fundamental sort for a sovereign entity" and for which "Congressional interference would upset the usual constitutional balance of federal and state powers" and that, as a result, "'it is incumbent upon the federal courts to be certain of Congress' intent before finding that federal law overrides' this balance." 501 U.S. at 460 (citing *Atascadero*, 473 U.S. at 243).

[24] 461 U.S. 190 (U.S. 1983).

> many years and in great detail by the States. As we noted in *Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, ... "There is little doubt that under the Atomic Energy Act of 1954, state public utility commissions or similar bodies are empowered to make the initial decision regarding the need for power.' Thus, 'Congress legislated here in a field which the States have traditionally occupied. ... So we start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress."[25]

In *Pacific Gas & Electric*, the Court held that Congress did not make its intentions clear and manifest because the Atomic Energy Act of 1954 only regulated the "safety aspects involved in the construction and operation of nuclear plants" and did not expressly authorize any federal agency to make decisions on the need, cost, reliability, and feasibility of building a nuclear power plant (which are matters traditionally reserved to states).[26] As a result, the Court was unwilling to interpret broadly the Atomic Energy Act to override a Californian law that the Court determined had been adopted to address the "economic problems" that could result from constructing a new nuclear power plant without insufficient spent fuel storage capacity.[27]

On other occasions, however, Congress has made its intentions clear and manifest when enacting federal laws that involve the regulation of electricity generation. One such case is section 201(b) of the Federal Power Act,[28] in which Congress expressly authorized the Federal Energy Regulatory Commission and its predecessor agency, the Federal Power Commission, to regulate the interstate sale of electricity at wholesale, and the transmission of electricity in interstate commerce, but also specified that this jurisdiction did not extend to the generation of electricity.

In addition, Congress developed a number of related federal policies that specifically directed EPA or other federal agencies to encourage the use of coal to generate electricity in response to the energy crises during the 1970's. One such example is the Energy Supply and Environmental Coordination Act of 1974,[29] which authorized the Federal Energy Administrator to issue orders requiring <u>existing</u> power plants to convert from using natural gas or fuel oil to coal for the generation of electricity. Similarly, Congress enacted into law the Power Plant and Industrial Fuel Use Act of 1978,[30] which – among other things – prohibited the construction of any <u>new</u> baseload power plant that did not have "the capability

[25] 461 U.S. 190, 205-206 (U.S. 1983) (citations omitted).
[26] 461 U.S. at 190.
[27] 461 U.S. at 222-23.
[28] 16 U.S.C. 824b(b)
[29] The Energy Supply and Environmental Coordination Act of 1974, codified at 15 U.S.C. 792. The authority of the Federal Energy Administrator to issue orders requiring coal conversions expired on December 31, 1978. *See* 15 U.S.C. 792(f).
[30] 42 U.S.C. 8301 et seq.

to use coal or another alternate fuel as a primary energy source."[31] In both cases, Congress provided explicit and unmistakably clear authority to regulate electricity generation, a traditional state sovereign function, in order to conserve the use of natural gas and petroleum for uses other than the generation of electricity.[32]

## IV. EPA LACKS AUTHORITY TO ADOPT A PROPOSED NSPS THAT REGULATES THE GENERATION OF ELECTRICITY.

### A. The CAA does not contain "unmistakably clear" language authorizing EPA to regulate electricity generation.

As the discussion above indicates, the regulation of electricity generation is a quintessential state sovereign function that EPA has an obligation to respect and preserve. Furthermore, well-established court precedent clearly prohibits EPA from adopting regulations or requirements relating to electricity generation, such as the use of any particular fuel or electric generating technology, unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes EPA to do so. A review of relevant statutory language indicates that neither section 111 nor any other provision of the CAA expressly authorizes EPA to adopt its "no-new-coal" energy policy that would be implemented by the proposed $CO_2$ NSPS for power plants.

Section 111 of the Act does not reflect a clear and manifest intent of Congress for EPA to adopt performance standards that require the use of any particular fuel or technology.[33] Rather, the statute confines EPA authority to only one matter – the establishment of performance standards for air pollutants emitted from new stationary sources falling within a source category listed for regulation under section 111(b)(1). In particular, section 111(a)(1) directs EPA to establish performance standards that "reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which ... the Administrator determines has been adequately demonstrated." In making this determination, EPA is allowed only to consider "the cost of achieving such reduction" as well as "any non-air quality health and environmental impact

[31] 42 U.S.C. 8311(a), (d).

[32] In addition, Congress' clear and manifest intent for the federal government to intrude upon a traditional state sovereign function is further evidenced by a conforming amendment that Congress adopted in 1978 to the Clean Air Act. This amendment clarified that a "coal conversion by reason of an order issued" under the Energy Supply and Environmental Coordination Act of 1974 or other related federal statutory provisions "shall not be a modification" for purposes of the NSPS or New Source Review (NSR) programs. *See* Section 111(a)(8) of the Clean Air Act. Congress added this new provision in order to prevent the stringent NSPS and NSR requirements from preventing or delaying a coal conversion.

[33] In its recent decision in *City of Arlington, Texas et al., v. FCC*, No. 11-1545, decided May 20, 2013 (holding that "courts must apply the *Chevron* framework to an agency's interpretation of a statutory ambiguity that concerns the scope of the agency's statutory authority (i.e. its jurisdiction)"), the Supreme Court held that intrusion on matters of traditional state and local concern was not an issue because the relevant statutory provision explicitly supplanted state authority. Slip op. at 14. No such clear and manifest indication of intent is applicable to EPA's proposal to ban coal use or otherwise regulate the generation of electricity under section 111(b) or any other provision of the CAA.

and energy requirements." However, nothing in section 111 or other provisions of the CAA expressly authorizes EPA to regulate the generation of electricity or other such energy regulatory matters traditionally reserved to states. This lack of express authority confirms Congress' intent to respect and preserve the states' historic role over the regulation of EGUs on electricity generation matters.

The CAA also contains explicit language indicating Congress' clear intent that EPA should not get involved in electricity generation matters relating to the use of any particular fuel or technology. This congressional intent is reflected in section 111(b)(5), which expressly bars EPA from requiring "any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[34] In effect, this statutory prohibition makes it crystal clear that Congress has no intent of authorizing EPA to regulate electricity generation, let alone manipulate fuel markets, or to pick winners and losers among alternative electric generation technologies. Picking winners and losers is, transparently, EPA's true purpose here. EPA's proposal would effectively implement a "no-new-coal" energy policy for electricity generation and would do so by adopting a $CO_2$ performance standard that only NGCC units would be able to achieve.

### B. EPA has respected and preserved states' sovereign authority to regulate electricity generation in past NSPS rulemakings.

Since the early 1970's, EPA has adopted NSPS for fossil-fueled power plants on many different occasions. None of these NSPS rules have imposed requirements that regulate electricity generation, let alone ban the future use of coal to generate electricity by new power plants. Moreover, the Agency has not just historically respected and preserved states' sovereign function to regulate electricity generation in past NSPS rulemakings, but has gone to great lengths to adopt performance standards that are technology and fuel neutral.

One notable example is the Subpart Da NSPS that the Agency promulgated for coal-fired EGUs in 1979. In this instance, EPA carefully crafted a stringent $SO_2$ performance standard that mandated the use of flue gas desulfurization (FGD) systems for the first time, but did so in a manner that would not preclude the use of significant portions of the nation's high-sulfur coal reserves. EPA accomplished this objective by adopting a new $SO_2$ percent reduction requirement for the FGD system,[35] but retaining the existing $SO_2$ emissions limitation of 1.2 lbs/MMBtu, as established under Subpart D, for coal-fired EGUs. Notably, EPA's rationale for retaining the current $SO_2$ limitation was that a more stringent $SO_2$ standard could preclude the use of "a significant portion (up to 22 percent) of the high-sulfur

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[34] This statutory prohibition is subject to one exception for work practices or operational standards under section 111(h) of the CAA, which is not relevant to EPA's proposal. *See* Section 111(a)(5) of the Clean Air Act.

[35] Notably, EPA set a variable $SO_2$ percent reduction requirement (70 percent to 90 percent reduction) in order to "provide an opportunity for dry $SO_2$ technology to be developed for all low-sulfur coal reserves." In so doing, the variable NSPS standard "serves to expand environmentally acceptable energy supplies without conveying a competitive advantage to any one coal producing region." 44 Fed. Reg. at 33,583.

coal reserves in the Eastern Midwest and portions of Northern Appalachian coal regions."[36] Specifically, EPA concluded that a tightening of the $SO_2$ limit – although technically feasible – "could create a significant disincentive against the use of these [high-sulfur] coals and disrupt the coal markets in these regions."[37]

Similarly, EPA has gone to great lengths over the last 40 years not to adopt NSPS limits for any air pollutant that might preclude the use of any particular fuel for the generation of electricity. This was most recently reflected in the revisions to the NSPS that EPA adopted in 2012 for fossil-fueled EGUs. In that prior rulemaking, the Agency concluded it was unreasonable to establish performance standards for conventional air pollutants (*i.e.*, $SO_2$, $NO_x$, and PM) that are achievable by only gas-fired power plants. In particular, the EPA provided the following rationale for its conclusion in the response to comments on the final NSPS rule:

> Basing the standards on [natural gas or distillate oil] would result in standards that are neither technically nor economically achievable for a coal-fired [power plant]. Basing the amended standards on the use of natural gas would preclude the development of new coal-fired [power plants] since the standards would not be technically achievable . … Therefore, basing the NSPS on [natural gas] emissions would not be achievable for coal-fired [power plants] with any technology that EPA is aware of.[38]

For these reasons, the Agency rejected adoption of performance standards based on emissions from a natural gas-fired power plant that would "essentially prohibit the construction of new coal-fired [power plants]."[39]

## V. CONCLUSION

In the case of the Clean Air Act, Congress did not provide any specific authority for EPA to adopt federal laws that preempt or otherwise intrude upon traditional state sovereign powers to determine the need for, and economics of electricity generating capacity, or to preclude the use of particular fuels or technologies to generate electricity. Notwithstanding the lack of any such clear and manifest intent of Congress, EPA has attempted to use its general authority under section 111 to regulate emissions from new fossil-fueled power plants in order to adopt a "no-new-coal" energy policy that overrides state energy laws and thereby infringes upon a sovereign regulatory function reserved to the States by the tenth amendment of the Constitution and the federal system. Congress' failure in the CAA to

[36] 44 Fed. Reg. at 33,596.
[37] 44 Fed. Reg. at 33,596.
[38] EPA, Response to Public Comments on Rule Amendments Proposed May 3, 2011, Section 2 at 1-2 (December 2011) (herein after referred to as "EPA Response to Public Comments on 2011 NSPS Proposal").
[39] EPA Response to Public Comments on 2011 NSPS Proposal, Section 2, at 2.

provide an explicit "unmistakably clear" authorization for EPA to regulate energy matters pertaining to the use of coal and other fossil fuels to generate electricity is another reason why EPA lacks authority to adopt the proposed $CO_2$ performance standard that bans the use of coal. For this reason, as well as the reasons presented in AEP's initial comments filed on June 25, 2012, EPA's proposed NSPS rule is fatally flawed and therefore should be withdrawn in its entirety.

AEP strongly supports the decision for EPA to develop a new $CO_2$ NSPS proposal for new EGUs. In developing that new proposal, EPA must respect and preserve the states' historic role over electricity regulation, and not develop a standard that has the effect of regulating energy production. These matters are quintessentially outside the purview of the regulatory programs entrusted to EPA.

The same limitations apply to any standards developed for modified, reconstructed, or existing sources. And for these standards EPA must keep in mind the broad discretion granted to the states in fashioning programs to implement the federal emission guidelines for existing sources under section 111(d). State energy and environmental authorities can examine any performance standard developed by EPA and determine if more flexible means are available to achieve the same goals at a more affordable cost, without compromising electric reliability, and taking into account the broader economic implications of altering the mix of generating resources within the state. EPA should not foreclose states from exploring such opportunities in the development of plans to implement any standards adopted under Section 111(d), but the timing, stringency, and optimal mix of resources dedicated to achieving the standards adopted by EPA are matters clearly entrusted by Congress to the states.

Should you have any questions or need clarification regarding these supplemental comments, please direct them to me at (614) 716-1268 or Janet Henry, Deputy General Counsel, at (614) 716-1612.

Respectfully Submitted,

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**J. McCabe, US EPA Acting Administrator Air & Radiation**
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# Appendix F

## AEP Comments Submitted on the Social Cost of Carbon

<u>**Comments of American Electric Power**</u>

**Technical Support Document, Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866**

**Submitted Electronically to: The Office of Management and Budget**

**Attention: Docket OMB-OMB-2013-0007**

**February 26, 2014**

**Summary**

American Electric Power (AEP) believes the Social Cost of Carbon (SCC) is inadequate and flawed mechanism to monetize benefits that may accrue from reductions in domestic greenhouse gas emissions. The lack of transparency in model development, lack of peer review, as well as the inclusion of a broad number of unsubstantiated assumptions makes the SCC values developed highly speculative and not appropriate for use in policy development or Regulatory Impact Analysis. Additionally, the post-processing of the Integrated Assessment Model (IAM) results, using averages of various model outputs and scenarios, is completely arbitrary for the evaluation of emission reduction benefits. Furthermore, the model's geographic scope and time period analyzed in development of the SCC values is completely inconsistent with corresponding analysis of regulatory costs. Until these issues can be resolved with firm scientific and public consensus or an alternative valuation system be developed, the SCC should not continue to be used in Regulatory Impact Analysis. AEP encourages the Interagency Working Group to explore alternative systems to more appropriately value carbon costs and benefits in the future.

**The Use of Integrated Assessment Models for SCC Value Calculations is Highly Problematic**

Underpinning the Social Cost of Carbon values are Integrated Assessment Models (IAMs), which are designed to evaluate the interplay between environmental impacts and economic conditions. These models were developed to explore the possible future trajectories of human and natural systems, answer key questions regarding climate policy development, coordinate assumptions and identify future research needs. As the IAM models are designed for largely exploratory purposes, many of their assumptions and functions still lack a firm routing in proven scientific or economic theory at this point. The Interagency Working Group has pointed this fact out numerous times in the SCC technical documentation and concludes they are in fact "imperfect and incomplete." IAMs are not meant to be predictive tools but rather producers of what-if scenarios of an evolving world.

While the IAM models used to develop the Social Cost of Carbon have been routinely cited in peer-reviewed literature, it is unclear that the models have been subject to direct peer review. As the assumptions play a paramount part in driving the results and conclusions, each assumption parameter and variable needs to be appropriately documented and peer reviewed. This type of work is already done with many models used to calculate policy costs, such as the IPM model used by EPA, and a similar structure should be followed for the IAM models. The lack of consistency and consensus as to these assumptions is evident in the inconsistent and conflicting results of different model running the same scenarios. As an example, in the low temperate increase scenario, one of the models predicts net benefits while two other models predict significant costs. Furthermore, past assessments of IAM model results have concluded that the calculated climate damages are often derived from very different sources (e.g. market, non-market & catastrophic) suggesting further disagreement and inconsistency.[1] **These conflicts need to be reconciled before the model outputs can be deemed ripe for use in regulatory development or analysis.**

**Economic Damage Functions used to Calculate the SCC are Highly Speculative**

The IAM models are populated with a chain of assumptions and functions used to translate Greenhouse Gas (GHG) emissions into changes in atmospheric GHG concentrations, GHG concentrations into temperature changes and temperature changes into economic damages. These estimates include economic growth, emissions projections, carbon cycle response, atmospheric concentrations, climate sensitivity, temperature increases, weather effects, and damage functions. The use of damage functions is particularly troubling as there is only a small amount of economic theory and literature to support them and what supporting literature has been developed is not necessarily representative globally. Additionally, the types of damages assessed appear to vary greatly between the three IAM models.

Robert Pindyck perhaps best characterized this situation in stating: "damage functions used in most IAMs are completely made up, with no theoretical or empirical foundation."[2] The Interagency Working Group substantiates these findings concluding there is a "limited amount of research linking climate impacts to economic damages" and that there is "the need for additional research." **However, the avoided economic damages pulled from the IAM models are in fact the sole output that is used to derive SCC values. Thus the SCC values are inherently rooted in incomplete science and economic theory.**

**IAM Models Fail to Adequately Account for Climate Adaptation**

There is also concern about how the IAMs incorporate adaptation as a means to abate economic damage. First, there is no consistent framework for treating adaptation between the three models, which may account for the significant difference in model results. Also, it appears some abatement opportunities are treated exogenously while others are treated endogenously. Many of these assumptions surrounding abatement appear to be crude and arbitrary with no recognition of increased technical abilities likely to emerge in the future. Additionally, it does not appear abatement opportunities are characterized for each sector in which damages may be calculated. **There needs to be**

[1] Joseph E. Aldy, et al, "Designing Climate Mitigation Policy", Resources For the Future, RFF DP 08-16, May 2009. P. 50. http://www.rff.org/RFF/Documents/RFF-DP-08-16.pdf

[2] Robert S. Pindyck, "Climate Change Policy: What Do The Models Tell Us?" National Bureau of Economic Research, Working Paper 19244, July 2013.

**further research into adaptation functions to ensure that the estimated damages are not significantly overstating the true economic cost of climate change.**

**The Emission/Economic Scenarios Bias SCC results to Improbably High Values**

Five emission and economic scenarios were modeled in development of the Social Cost of Carbon, based on EMF-22 scenarios, representing a range of emission trajectories. However, four out the five scenarios suggest that emissions will continue to rise largely unabated through 2100, reflecting in the words of the Interagency Working Group, business as usual (BAU) or an emission "pathway absent mitigation policies." This seems widely inconsistent with both current U.S. policy objectives and plausible reality.

Actions by the U.S., European Union, Japan, Australia and a number of other nations to abate emissions show that there is a growing consensus that climate action is taking place and further action is needed going forward. This would suggest that the high emission growth scenarios are likely not to occur due to action already occurring and likely to continue in more substantial fashion going forward with other nations beginning to plan for emission reduction pathways, most notably the world's largest GHG emitter, China.

In the high unlikelihood that large-scale international climate action does not occur in the next few decades, there still remains a large number of years (until the end of the IAM assessment period in 2300) in which to better and more precisely detect actual climatic impacts, characterize future climatic impacts and conclude that emission reduction actions or adaptation measures are needed. These actions could dramatically change the emission and temperature trajectories and thus static assumptions on emission trajectories, particularly those extrapolated post-2100 are highly arbitrary and likely not to transpire. **These conclusions regarding climate action suggest that the BAU scenarios used in SCC development are in fact not likely and are skewing the damages to higher values than otherwise probable.**

The choice of running the IAM model scenarios out to the year 2300 is also concerning. While CO2 has a long atmospheric lifetime and the carbon cycle has inertial effects, making assumptions about socioeconomic factors and climatic factors over such a long time horizon is very tenuous at best. In fact, all data past 2100 is extrapolated, as EMF-22 assumption data ends at that point. To suggest that trends continue in a linear or constant fashion out until 2300 is highly arbitrary. The world of 2300 is likely to look much different that today, thus using assumption and linkages supported by narrow bands of data today may not be technically sound in a much different future. **AEP would suggest using a shorter time for analysis in which the assumptions can be more readily supported.**

**U.S. Specific SCC Values should be used for U.S. Regulatory Evaluations NOT Global Values**

In addition to the uncertainty in regional IAM model assumptions, inputs and outputs, there no regional differentiation of the ultimate model results. Simply assuming that the U.S. bears a proportion of the global economic damages is highly arbitrary and almost certainly wrong. **Social Cost of Carbon**

**values for use in U.S. specific analysis should be derived solely from calculated U.S. economic damages.**

Most economists would agree that due to the high level of economic development within the U.S., the U.S. will be better able to adapt and respond to any climatic effects than less developed countries. This suggests using an average marginal global value, in addition to being incorrect in practice, is likely significantly overstating the marginal damages that may accrue to the U.S.

The sensitivity of the results to discount rate indicates that some of the major economic damages may not occur until well into the future. **The undiscounted impacts should be disclosed on a year-by-year basis to allow for evaluation of the timing of impacts over such as long time horizon.** This will better aid policy makers in making balanced policy decisions affecting current society given the uncertainty in the projections. Additionally, there is concern with using discount rates below previous guidance given by OMB.

**The Development of SCC Values is Not Analytically Correct**

As stated previously, IAMs are not meant to be predictive tools, but rather producers of what-if scenarios in an evolving world. However, in the case of the Social Cost of Carbon, a methodology is employed to use model outputs to produce absolute values regarding the level of carbon abatement that is current economically optimal. **As a result of the SCC development process and the focus on a central value for regulatory analysis, the models are in-fact being used as a predictive tool, which is not what they are designed for.**

The Social Cost of Carbon values are based the average marginal abatement values across the three models and the five socioeconomic scenarios for each discount rate. It is improper to use such a wide range of emission scenarios in the modeling process in the development of the SCC. While there is uncertainty of future international action, as previously commented upon, one must assume that current political efforts and basic human nature in response to impending impacts will in fact result in emission reductions, particularly given the long time horizon for analysis, leading to lower and narrower emission paths than currently assessed. The wide-band of scenarios currently analyzed also accentuates any tail-effects the models may pick up from scenarios with high levels of temperature increase and skew the average.

Due to the inconsistent results and wide range of impacts, averaging the model outputs is a not a statistically sound way to aggregate the data. Extreme values in certain model scenarios drive average values higher. Absent evidence these extreme values not outliers, using a median value approach may be more statistically sound in developing a central value. However the publishing of undiscounted damage values and types of impacts expected would allow for proper assessment of the statistical method required, taking into account risk tolerance.

There is considerable uncertainty as to the proper discount rate to use for intergenerational accounting, but the discount rate used in climate change cost-benefit analysis is highly important given the fact, that as currently modeled, the majority of damages appear to be loaded in later years. Use of a low discount rate would suggest allocation of current capital resources to emission abatement efforts at the expense of current growth as higher yielding near-term investments might not be allocated capital. This is concerning in light of all the uncertainty in the models. As mentioned previously, several of the discount rates used currently used are lower than OMB guidance.

**Costs-Benefits Do Not Match Spatially or Temporally**

As mentioned previously, the SCC values are established based on a global measure of benefits. This is inconsistent with current policy as to benefit evaluation of domestic regulation, which is calculated on solely a U.S. basis, based on guidance given through Executive Orders. Potential costs or benefits to other nations are not assessed within analysis of domestic policy. In order for a proper cost-benefit test to be conducted, **both cost and benefit analysis should be conducted with the same geographic scope.** As U.S. regulations are meant to protect the rights of U.S. citizens and residents both costs and benefits should be evaluated on solely the basis of domestic impact. Matching geographic scope is especially important with respect to carbon emissions, as emission leakage is a well-established phenomenon, as discussed later.

The SCC values being developed based on modeling out until the year 2300 also creates a major temporal disconnect between how costs and benefits are evaluated. Typical cost analysis of regulatory proposals only runs for a decade or two at most, with most Regulatory Impact Analyses citing uncertainty or lack of concrete data beyond that point preventing longer-term analysis. **While, it is encouraged that the SCC analysis be truncated well prior to 2300, it also is recommended that assessments of policy costs with respect to carbon take on a similar, longer time-period for analysis, regardless of uncertainty.**

**There Will Be Negative Trade Impacts of SCC Use on the U.S. and Emissions Leakage Problems**

The SCC values, as currently developed, expose U.S. businesses to a trade disadvantage, as other countries are not using similar carbon values in their policy regimes. Carbon allowances in the European Union and Australia for instance (with limited scope of coverage), trade far below the values that are currently being applied to regulations across all industries in the U.S. in policy analysis. Furthermore, China, a major importer of goods to the U.S., has no national carbon price. As the costs of additional regulation driven by SCC values ripple through the economy, businesses that produce carbon intensive goods will be subject to higher costs and become less competitive. Furthermore, the push to include these SCC valuations in regulatory analysis ignores the fact that U.S. emissions have declined while emissions from developing countries are likely to increase.

International competitiveness will be particularly important going forward with the ongoing development of GHG regulations for the electric sector. As the electric sector is carbon intensive and a large amount of goods produced in the U.S. have value added through electricity, additional costs associated with carbon regulation will translate in to higher domestic production costs. U.S. manufactured goods will be placed at an economic disadvantage to those produced abroad and production of these goods and corresponding GHG emissions will shift elsewhere. Emission leakage is well-established phenomenon that occurs between markets that place a different value on emissions or reductions. Leakage can also occur through regulation displacing domestic demand for fossil fuels, thus lowering the price and encouraging additional consumption in other sectors and in other countries. These types of shifts in emissions have not been considered to date in Regulatory Impact Analysis. **Without taking into account leakage, forecasting emission reductions in one sector and applying the Social Cost of Carbon will result in an overstating of net emission benefits. This area needs further exploration by the Interagency Working Group and OMB and firm guidance should be provided to address leakage.**

Social Cost of Carbon values can also be routinely updated exposing U.S. industry to never-ending policy uncertainty, which will play havoc on capital allocation. As many of the assumptions and linkages within the model are not well understood, a single variable could change the SCC values quite dramatically. This was recently evident as the updated SSC values were more than 50% larger than those previously published. **Thus, there needs to be a fixed period for peer-review and public comment to update the SCC values. Given capital allocation looks out over a long time horizon, a 10-year review cycle or longer is warranted.**

**Cost-Benefit Assessments Must Also Include the Economic Benefits of Lower Cost Energy**

Last, the calculation of the social cost of carbon values focuses almost entirely on the negative impacts associated with global climate change and ignores the benefits provided from the use of low-cost energy resources in lieu of more expensive albeit lower carbon alternatives. While the costs of abating emissions are generally picked up as part of a regulatory assessment of costs, the indirect benefits to economic growth, human health and well-being are not typically analyzed. **If an effort is being made to internalize all externalities within cost-benefit analysis, these types of benefits also need to be considered.**

**Final Recommendations**

The Social Cost of Carbon should not be used in further Regulatory Impact Analysis until outstanding issues regarding its development can be rectified. Among the major issues to be resolved are including public input and peer review of all model assumptions, ensuring calibration and agreement between models, use of narrower emission scenarios, using only projections of domestic damages, truncating model results to be consistent with evaluation of policy costs, providing for appropriate analysis of emission leakage and providing a consistent long-term period for updating of SCC values.

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EPA Docket Center
U.S. Environmental Protection Agency
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1200 Pennsylvania Ave., NW
Washington, DC 20460
ATTN: Docket ID No. EPA-HQ-OAR-2013-0602

Re: *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* EPA-HQ-OAR-2103-0602; Proposed Rule 79 Fed. Reg. 34829 (June 18, 2014)

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* 79 Fed. Reg. 34,829 (June 18, 2014), under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP affiliates that own and operate electric generating units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

Re: *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* EPA-HQ-OAR-2103-0602; Proposed Rule 79 Fed. Reg. 34829 (June 18, 2014)

AEP's comments cover a wide range of issues, including EPA's interpretation of the scope of its legal authority to control all aspects of the generation, transmission, distribution and use of electric energy, as well as a detailed examination of the technical information underlying EPA's calculation of individual state emission rate "goals," the proposed schedule for development and submission of state plans, and the challenges of demonstrating compliance with the interim and final goals. Based on these concerns, AEP recommends that EPA withdraw the current proposal, address the significant legal, technical, and practical flaws that exist, and re-propose the guidelines for public comment. A summary of our comments and key recommendations are provided in the executive summary that follows below.

In addition to these comments, AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), the Electric Power Research Institute (EPRI), and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

We appreciate the opportunity to submit these comments, and hope to continue the dialog the agency has conducted during the development of this proposal. These issues have vast energy, economic, and environmental implications, and deserve thoughtful consideration.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

John M. McManus

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American Electric Power

Comments to EPA Regarding the

*Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* Proposed Rule
EPA-HQ-OAR-2103-0602
79 Federal Register 34829
(June 18, 2014)

Submitted December 1, 2014

**Executive Summary and Recommendations:**

EPA states that the proposed Clean Power Plan ("CPP") is "*an important step toward achieving the GHG emission reductions needed to address the serious threat of climate change.*"[1] However, in taking that step, EPA has overstepped its statutory authority, and ignored the legal, technical, and practical limitations that govern the production, delivery, and use of electricity in the United States. Efforts have already been made, and continue to be made, by AEP and others to reduce greenhouse gas emissions from fossil-fueled electric generating units ("EGUs"). Additional dramatic changes in the nation's portfolio of generation resources and their associated emissions will continue in the near-term due a number of regulatory, market, and other drivers. For example, implementation of the Mercury and Air Toxics Standards.[2] and Regional Haze requirements[3] will result in AEP alone permanently removing over 6,000 megawatts ("MW") of coal-fired generating capacity from service and converting an additional 730 MW from coal- to gas-firing. Others are taking similar steps. Yet EPA provides no comprehensive assessment of the emission reductions resulting from these actions in order to determine whether, and if so, how much more reduction can and should be achieved, consistent with the requirements of section 111 of the Clean Air Act.

In its fact sheet released with the CPP, EPA claimed that the proposal would result in a 30 percent reduction in $CO_2$ emissions from 2005 levels for the power sector by 2030.[4] However, based on the guidance released on November 13, 2014, the actual reduction in $CO_2$ emissions from the existing fossil fleet required by this proposal on a mass basis is 30 percent *from 2012 levels* by 2030.[5] For the AEP fleet, this means that the 20 percent reduction in emissions already achieved from 2005 levels is completely disregarded, and deep additional cuts will be required to satisfy the goals established by EPA.

Section II of these comments provides a brief overview of the CPP, and a description of EPA's statutory authority under section 111(d) is provided in Section III. In the detailed sections that follow, AEP discusses the legal flaws in EPA's interpretation of the phrase "best system of

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[1] 79 Fed. Reg. 34,833.
[2] 40 CFR Part 63, Subpart UUUUU.
[3] 40 CFR §51.308.
[4] http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-overview.
[5] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice, Additional information regarding the translation of emission rate-based $CO_2$ goals to mass-based equivalents,* 79 Fed. Reg. 67,406 (November 13, 2014).

emission reduction" ("BSER"), and the legal and technical deficiencies in EPA's development of each of the building blocks. A brief summary of the balance of AEP's comments follows.

Summary of Section IV – EPA's Interpretation of "BSER" is Fatally Flawed

This proposal is wholly different from any prior emission limitation, standard, or guideline developed by EPA under the CAA. If adopted, the CPP would establish an expansive and unprecedented program to regulate the production, delivery, and use of electricity in the United States. The assumptions that EPA uses to develop state goals supersede the authority granted to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, contain significant and fundamental technical flaws regarding the nature and operation of electricity generators and the electricity grid, and intrude upon authority reserved to the states. The proposal also is contrary to the express requirements of section 111 of the CAA, and EPA's own regulations, in several significant respects.

A fatal defect in EPA's CPP is the proposal's dependence upon an abstract, out-of-context interpretation of "system" in the phrase "best system of emission reduction" in the section 111 definition of "standard of performance." EPA's unprecedented interpretation of the word "system" in the "standard of performance" definition is disassociated from, and in conflict with, the interlinked CAA definitions of "stationary source," "existing source," "emission limitation," and "performance standard," and with the legislative history of Section 111. It is also in conflict with EPA's existing regulations that implement section 111, and at odds with EPA's interpretation and application of section 111 throughout its 44-year history. Rather than reflecting the degree of emission limitation achievable by applying a demonstrated technology-based (or work practice) system of emission reduction to the affected EGU, as the statute plainly directs, the proposal requires a reduction in the hours of operation and/or rate of production (or complete shutdown) of affected EGUs, a result contrary to the text and structure of the statute, and that could not have been imaginable to the Congresses that enacted and amended the CAA in 1970, 1977, and 1990.

Never before has EPA claimed the authority to limit productive capacity or control the rate of customer usage of a particular product, and the assertion of authority to do so here has no foundation in the CAA. Because EPA's interpretation would purport to give EPA broad power to regulate human behavior, EPA's interpretation of "system of emission reduction" must be rejected.

Summary of Section V - Building Block 1 Comments

EPA mischaracterizes observed variability in heat rate at coal units as being "evidence" that existing coal-based generating units are not being adequately operated or maintained.[6] Heat rate performance is influenced by a variety of known and unknown, controllable and uncontrollable factors, whose interaction is unit-specific and varies throughout the life of the unit. Moreover, EPA's examination of opportunities to improve heat rate either ignores or does not fully consider the following factors:

- the availability, technical viability, and economic feasibility of potential improvement opportunities at individual units;
- heat rate improvement measures that have already been implemented;
- unit-specific factors that influence the magnitude and sustainability of potential heat rate improvements; and
- other environmental regulatory requirements that may mask or eliminate opportunities for potential heat rate improvements.

There is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed units within the existing fleet (both coal-fired and non-coal units) to maintain and improve efficiency through adoption of best practices. Had EPA fully considered these factors, the agency would have correctly concluded that both the proposed 6% and alternative 4% targets for heat rate improvements are overly aggressive, and cannot feasibly be implemented by the majority of existing coal-based generating units because:

- There is a wide range of inherent limitations on the potential for heat rate improvements, including original design, geographic location, availability of space, emission controls, and prior improvement efforts;
- Unit efficiency naturally degrades over time;
- There is no accurate method to measure heat rate in real time;
- Heat rate improvements may be masked by control technology installations or changes in duty cycle; and
- Remaining useful life will affect the economic feasibility of continued efficiency investments.

There is no single emission standard or limitation that is achievable or adequately demonstrated for all regulated sources. Instead, EPA should rely on Section 111(h)(1) of the

[6] "GHG Abatement Measures TSD". U.S. EPA. June 10, 2014. p. 2-1

CAA, which authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof, when it is not feasible to establish a standard of performance, and develop a work practice standard for EGUs. Such a standard would assure that cost-effective changes are routinely made at existing units, consistent with the criteria contained in section 111(d).

Summary of Section VI - Building Block 2 Comments

Building block 2 is based on EPA's generalized assumption that *all* existing NGCC units can be redispatched to sustainably achieve a 70% capacity factor, and that the additional generation provided by the existing NGCC units will *exclusively* offset generation from other, higher-emitting, existing fossil-fueled units. The underlying analysis that supports this assumption relies on inaccurate data, and generally represents a poor understanding and application of the basic concepts and operating metrics used to assess historic and future unit performance. The result is an assumed level of performance that simply has not been adequately demonstrated to be achievable across the fleet of existing NGCC units.

Further, EPA fails to explain how this building block is consistent with section 310 of the Clean Air Act,[7] which specifically preserves the authority of all other federal agencies, when such requirements for "environmental dispatch" would effectively override the system of security constrained economic dispatch created by the Federal Energy Regulatory Commission ("FERC") and implemented through regional transmission organizations ("RTOs"), independent system operators, and other balancing authorities, as required by the Federal Power Act.[8]

Even if such a concept could be incorporated into a section 111(d) standard, the level of operation assumed by EPA in calculating the state goals contains fundamental errors, such as: (1) relying on nameplate capacity instead of net demonstrated capacity (which results in about a 10% increase in the goals that cannot reasonably be achieved); (2) including units that are not designated facilities; (3) failing to accurately and consistently account for units that operated for only a portion of 2012, or were not yet operating; and (4) failing to adequately evaluate the availability of gas pipeline capacity to deliver fuel and transmission capacity to deliver power, and the time and cost necessary to increase capacity if it is not already available. EPA's own

[7] 42 U.S.C. § 7610(a).
[8] 42 U.S.C. § 824(b).

policy case modeling does not achieve the level of operation assumed by EPA in calculating the state goals.

EPA must present a proposal that, at a minimum, is grounded in accurate, complete data and that reflects the actual operation of the electricity grid. Given the egregious nature and scope of concerns to be resolved in building block 2 *alone*, EPA should withdraw the current proposal and publish a new proposed rule for public comment.

Summary of Section VII - Building Block 3 Comments

EPA has not cited, and AEP has not discovered, any statutory basis for the inclusion of generation from new and existing non-emitting nuclear and renewable resources in its calculation of state goals to regulate emissions of fossil-fueled EGUs. Such units are not "affected facilities" in the listed source categories for which these guidelines are proposed, nor would they be subject to any standards under section 111 if they were "new." EPA's expansion of its regulatory grasp far exceeds the scope specifically authorized by Congress, and invades the reserved powers of the States under the Tenth Amendment to the U.S. Constitution.

Moreover, EPA's use of individual state renewable portfolio standards to establish "regional goals" that each state must achieve is ill-informed, and overlooks distinctions among these state standards that either significantly reduce the absolute value of those standards, or rob the states of flexibility in implementing the goals, or both. EPA has also insufficiently evaluated the technical potential and cost of renewable resources across the states, and ignored significant questions related to the expansion of both intrastate and interstate transmission resources, regulatory processes, cost allocation, and timing.

Any goals established by EPA in the final rule cannot rely on nuclear or renewable resources. However, EPA should prescribe procedures for the development of state plans that allow states to determine if or how renewable resources may be included in their compliance plans.

Summary of Section VIII - Building Block 4 Comments

EPA also does not have clear authority from Congress to dictate energy policies that control customer demand, including the degree to which energy efficiency ("EE") measures should be adopted by individual customers.[9] Even if such authority existed, EPA has failed to demonstrate that the level of EE used to calculate the state goals is achievable or has been adequately demonstrated. Specifically, EPA ignores the expert evaluations of the majority of states regarding a reasonably achievable level of EE, the pace of increase in EE achievement, and a reasonable level of costs to achieve those proposed EE levels. Further, the data and methodology that the agency used in establishing these levels for all states in a one-size-fits-all manner ignores many fundamental differences between the states that affect the nature and scope of achievable EE measures and rates of growth. EPA did not use a transparent process in estimating the costs of the proposed EE levels, did not consider all cost elements of EE, and did not give adequate consideration to the ways such costs will affect customers. EPA's failure to specifically identify the evaluation, measurement and validation ("EM&V") methods required for a satisfactory state plan, and its failure to assess whether such EM&V measures are currently applied in the programs identified as "best practice standards," provide an inadequate basis for commenters to determine the actual impact of the proposed guidelines. Accordingly, EPA should not assume specific levels of EE achievement in developing any state-specific goals, but states should retain the flexibility to determine if or how EE measures may be included in their compliance plans.

Summary of Section IX – Implementation Concerns

The flaws identified within each of the building blocks collectively lead to serious concerns related to the practical implementation of the CPP. Because the errors identified in the development of each building block lead to a significant overstatement of its potential contribution to reductions in emissions from existing fossil-fueled EGUs, the combined whole represented in the state goals has not been adequately demonstrated and is not achievable. All

[9] Indeed, in the context of EPA's authority under Section 169 of the CAA to specify what is the "best available technology" for regulated pollutants in a new source review ("NSR") permit, the Supreme Court noted with approval that, "BACT may not be used to require 'reductions in a facility's demand for energy from the electric grid,'" and that "BACT should not require every conceivable change that could result in minor improvements in energy efficiency, such as the aforementioned light bulbs." Rather, the Court confirmed that BACT can only be required for pollutants that the source itself emits, and that permitting authorities should consider whether the proposed regulatory burden outweighs any emission reductions that can be achieved. *UARG v. EPA,* 134 S.Ct. 2427, 2448 (2014). These same principles should apply to the BSER, which is based on technology that can be applied to emissions from the regulated source, and must satisfy the statutory balancing of costs, other environmental affects, and the emission reductions actually achieved.

flexibility that would have been present had EPA accurately assessed each building block evaporates.

Moreover, EPA's proposal to extend compliance responsibilities to entities other than the "designated facilities" exceeds EPA's and states' authorities under the CAA, creates uncertainty regarding the ultimate enforceability of the state goals, and raises procedural and substantive due process concerns for sources within the regulated source categories if states elect to follow EPA's advice and reduce their plan requirements to goals enforceable only against those sources. EPA has ignored the requirement under section 111(d) to provide states with the flexibility to adjust the stringency of the final performance standard or the timing of the ultimate compliance schedule based on the remaining useful life of the regulated sources. And the timeline to achieve compliance is unreasonable, particularly for building blocks 1 and 2, both of which are proposed to be fully implemented by 2020. EPA has no authority to dictate the timing of implementation or to establish interim goals, and these are issues that should be reserved to the states as they develop final performance standards.

Summary of Section X – Transmission and Reliability Issues

The reliability and resource adequacy analysis performed by EPA is incomplete and inaccurate. It asks the wrong questions and provides answers developed using the wrong tools. Any analysis of the achievability of the CPP must be based on the tools used by reliability organizations to assess power flows under the conditions projected to occur as the CPP is implemented. Because EPA assumes that there will be dramatic changes in the composition, location, and characteristics of the generation fleet as a result of the CPP, such an analysis must be performed iteratively by organizations with the expertise and knowledge to analyze the dynamic nature of the impacts of these changes.

The North American Electric Reliability Corporation ("NERC") recently released a preliminary assessment of the stability and reliability of the grid if the changes envisioned in EPA's modeled outputs for its cost-benefit analysis actually occurred in 2020.[10] These changes will strain reliability and essential services, require expansion of the transmission grid, and are inconsistent with the planning horizons used to implement transmission reliability enhancements. The Southwest Power Pool ("SPP") has performed a similar analysis of the potential reliability

[10]http://www.nerc.com/pa/RAPA/ra/Reliaiblity%20Assessment%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

impacts within the SPP region. SPP found that: "1) the CPP will impact the reliability of the bulk electric system; 2) the timing proposed by EPA for compliance is infeasible; and 3) the proposed CPP will have material impacts on the market-based dispatch of electric generating units within the SPP region."[11] AEP's own internal analysis of the SPP and PJM regions within which it operates yielded similar results. Any future proposals must be accompanied by a comprehensive analysis that demonstrates that the security and reliability of the bulk power system will not be compromised.

Summary of Section XI – Assessment of EPA's Regulatory Impact Analysis ("RIA")

EPA's RIA lacks information on the full range of issues that should inform its assessment of the costs and benefits of the proposed CPP. There are startling inconsistencies between the assumptions used to calculate individual state goals and the results of EPA's modeled implementation that suggest that the assumptions underlying the individual building blocks are unreasonable, or that practical and economic constraints would produce results that vary significantly from those assumptions. EPA failed to include in its base case the existing and planned levels of EE based on current state program requirements, thus overstating the "benefits" of the CPP.

Further, the RIA has substantially underestimated the costs and the negative macroeconomic impacts (e.g. large job losses) of the CPP. This includes data errors and flaws in methodologies, which results in significant overstatement of the reduction capabilities of each of the four EPA building blocks and at the same time understates the actual costs of achieving these building block reductions. The RIA also fails to consider serious reliability constraints, which will require major electricity transmission investments as well as new natural gas pipelines and infrastructure. Not only will these investments result in significantly higher costs, they will also make achievement of the CPP interim reduction goal requirements infeasible in a number of states. EPA's analysis also improperly uses the "social cost of carbon" and collateral reductions of criteria air emissions to justify increases in the cost of electricity that will be disproportionately borne by those of low or fixed incomes.

[11] http://www.spp.org/publications/CPP %20Reliability%20Analysis%20Results%20Final%20Version.pdf

Summary of Section XII – Miscellaneous

There are important additional issues concerning EPA's lack of authority to regulate EGUs given its prior regulation of this source category in the MATS rule, the unlawful takings that would arise if the rule is implemented and enforced to require reduced utilization or retirement of existing units with remaining useful lives, the illegality of EPA's proposal to regulate modified and reconstructed units as both "new" and "existing" units, EPA's failure to clearly delineate the Title V requirements that will apply to area sources as a result of this proposal, the lack of coordination between this proposal and the anticipated issuance of a proposed ambient standard for ozone, and its failure to provide a reasonable opportunity for comment on the many additional issues raised for the first time in the notice of data availability ("NODA") released on October 30, 2014. Several of these issues are discussed at length in the comments of others, and those comments are incorporated by reference in this section.

Recommendations (Section XIII)

Electricity serves as the foundation of our nation's safety, security, and prosperity. EPA must take the time to carefully consider all of the comments submitted, and to issue guidelines that strike the appropriate balance between environmental protection and economic well-being. EPA should develop and issue for comment a proposal that includes the following elements:

(1) Heat rate improvements can be cost-effective ways to reduce $CO_2$ emissions, or to mitigate increases in $CO_2$ emissions, over the life of a fossil-fueled generating unit, regardless of fuel type or unit design. However, given the inherent variability in heat rate due to duty cycles and other uncontrollable factors, and the lack of an effective real-time heat rate measurement technique, it is infeasible to establish traditional emission limitations or standards based on improved heat rates. EPA should collect sufficient information about the techniques that could potentially be adopted to varying degrees at existing units (considering costs, lack of physical space, degree of prior adoption, remaining useful life, and other factors) and formulate a proposed guideline for a work practice standard that would allow for periodic evaluation of cost-effective heat rate improvement opportunities on a unit-specific basis, that can then be integrated into regularly planned outages across the existing fleet. Such a measure would ensure sustained adoption of available efficiency improvements within the existing fleet, which is the "best system of emission reduction" for these designated facilities.

(2) Encouraging reduced utilization of certain existing units and increased utilization of others is not authorized as a "means of emission limitation" under Section 302, and is inconsistent with the authorities granted to the Federal Energy Regulatory Commission (FERC) and the regional reliability organizations under the Federal Power Act (FPA). Section 310 of the Clean Air Act clearly states that EPA's authorities cannot be interpreted in such a way as to intrude upon the implementation of security constrained economic dispatch of the bulk electric system through the mechanisms FERC has developed under the FPA. However,

future emission reductions will occur through the natural aging of the existing fleet, and plans could be established based on the remaining useful life of existing units consistent with the express language of section 111(d). EPA should allow states to examine the emission reductions that will occur within the existing fleet as units near and reach the ends of their useful lives, and establish a glide path to lower total mass emissions from the existing fossil fleet. EPA should allow states to calculate the "degree of emission reduction" achieved through such a procedure, and to develop the path for reductions that is consistent with the energy and economic needs of the states. EPA has no authority to dictate arbitrary "interim" goals that the states must meet.

(3) Nothing in the Clean Air Act gives EPA the authority to specify the types of new generation resources that should be constructed to fulfill a utility's obligation to serve. This authority has been specifically reserved to the states under the FPA, and no Congress has yet passed laws to establish national renewable portfolio standards. However, EPA should allow states to examine the planned additions of renewable and other low- or non-emitting resources under existing integrated resource plans and other siting or certification requirements, and use any approved, cost-effective resource additions as creditable emission reductions, to facilitate the transition of the existing fleet to a cleaner, more modern system.

(4) Energy efficiency targets and goals have also been used by state utility regulators and state energy resource planning agencies as a means to delay the need for additional capital-intensive base-load generating resources, and to manage peak loads. States should be given the option to take credit for these efforts if they prove to be cost-effective, and as new technologies develop. However, EPA is not an energy planning expert or rate regulator, and these measures can only be developed consistent with the reserved power of the states for retail energy rate regulation. There is no single "best practice" that can be established for all states. Each state should be allowed to incorporate its energy planning strategy into a plan under section 111(d) to the extent it determines is appropriate.

Like the Clean Power Plan, the four recommendations listed above are not mandatory or federally enforceable requirements; they are merely guidelines to be used by the states as one of many factors that will contribute to the development of final state and regional plans. States would be free to identify other measures in their plans, if they are more cost-effective or better suited to individual state policies and resources. EPA's backstop authority under Section 111(d) would permit it to develop a federal implementation plan if a state fails to submit a satisfactory plan, but it could be based on only the first two recommendations, which directly control emissions from the regulated sources. Additional measures based on recommendations three and four would help states accommodate needs for increased flexibility, such as allowing the states to address units that have no cost-effective options for heat rate improvements due to site-specific factors, or where replacement of existing resources will require a longer compliance time frame due to the need for transmission mitigation or reinforcement, or other infrastructure additions.

**COMMENTS OF THE OPERATING COMPANIES OF THE AMERICAN ELECTRIC POWER SYSTEM ON THE CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE, 79 Fed. Reg. 34829 (June 18, 2014) EPA-HQ-OAR-2013-0602**

OUTLINE:





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document that “reflects the best system of emission reduction ... for *designated facilities*.”

E. EPA’s broad interpretation of “system of emission reduction” conflicts with its more limited interpretation of “system” in Subpart B and its current interpretations of “system” in other rulemakings.

F. EPA’s emission guidelines permit states to apply emission standards to both “designated facilities” and other entities, but Subpart B permits the application of emissions standards only to “designated facilities.”

V. The Emission Reductions Required by Building Block 1 Are Not Achievable

A. EPA should objectively and holistically consider the full range of issues that influence heat rate performance
    1. Heat rate improvement opportunities are unique to each unit
    2. Actual heat rate performance varies due to a number of known and unknown, controllable and uncontrollable factors
    3. EPA has overstated the potential heat rate improvements related to operating practices
        a. The design of EPA’s statistical analysis is fundamentally flawed
        b. EPA’s dataset contains inherent sources of variability
        c. EPA failed to account for physical and operational changes at existing units that affect potential heat rate improvement opportunities

B. EPA has overstated heat rate improvements related to equipment upgrades
    1. EPA’s use of a 2009 Sargent & Lundy study does not support the BSER determination on heat rate improvements from equipment upgrades
    2. EPA’s review of other documents discussing heat rate improvements does not support the BSER determination on heat rate improvements from equipment upgrades
    3. The unit-specific examples identified by EPA do not demonstrate that its heat rate improvement targets are achievable or adequately demonstrated.
    4. EPA fails to adequately address NSR related issues that challenge the efficacy of heat rate improvement opportunities

C. EPA fails to evaluate whether the 2012 heat rate data is representative of typical unit operations or if the application of a 6% improvement is feasible given prior improvement efforts and historic unit trends

D. EPA failed to examine heat rate improvement opportunities at other designated facilities

E. EPA should develop a work practice standard for heat rate improvements at designated facilities

VI. Building Block 2 Exceeds EPA's Authority and Is Based on Flawed Data and Methods

A. EPA lacks the statutory and regulatory authority to redispatch EGUs

B. EPA has not demonstrated that a 70% capacity factor is achievable by all existing NGCC units

C. The criteria used by EPA to evaluate NGCC performance and to determine a redispatch capacity factor as the BSER is flawed

D. EPA provides no legitimate rationale for determining that a 70% capacity factor is achievable by the entire NGCC fleet

E. EPA has not fully evaluated the transmission and gas supply infrastructure issues that may significantly impact the feasibility and amount of potential redispatch
   1. EPA should thoroughly evaluate natural gas supply issues
   2. EPA should thoroughly evaluate electric transmission issues

F. EPA failed to evaluate existing air permit conditions that may significantly impact the feasibility and amount of potential redispatch

G. EPA should exclude combined heat and power facilities from the building block two calculations for NGCC units
   1. CHP units should be considered separately from NGCC units
   2. EPA should evaluate whether individual CHP units are affected sources subject to the 111(d) guidelines
   3. EPA incorrectly applies the electric output associated with useful thermal output from CHP units in the building block two calculations

H. EPA has significantly overestimated the amount of NGCC capacity available for redispatch due to egregious methodological issues and data quality errors
   1. EPA incorrectly uses "nameplate" capacity in the block 2 calculations
   2. EPA incorrectly includes simple-cycle and gas boiler units in their calculation of "existing" NGCC capacity
   3. Building block two incorrectly and inconsistently includes NGCC units that were constructed after 2011
      a. In the calculation of existing NGCC capacity available in 2012, EPA incorrectly included units that had/have not yet been commissioned
      b. EPA has incorrectly calculated the post-2012 "under construction" NGCC capacity for <u>all states</u> where the agency determined it applied
      c. EPA fails to consider certain existing NGCC units that were commissioned during or after 2012
      d. EPA incorrectly accounts for NGCC units commissioned during 2012 in their calculation of potential redispatch amounts
   4. EPA must resolve significant data quality issues
   5. Building block two calculations are incorrect for all states identified by EPA as having applicable NGCC units

6. EPA must revise all aspects of the proposed rule that are impacted by the data quality and methodological issues identified for building block 2

I. Building Block 2 Comments related to EPA's NODA
   1. Phased Implementation of Building Block 2
   2. Consideration of Minimal NGCC Utilization in the BSER
   3. Regional Approach to Building Block 2

VII. Building Block 3 is unachievable

A. Renewable resources must be excluded from the determination of the best system of emission reductions for existing fossil fuel electric generating units
   1. Renewable resources are not affected sources under 111(b) and therefore cannot be regulated under 111(d)
   2. EPA has infringed upon States Tenth Amendment Rights

B. EPA's use of existing renewable portfolio standards to determine state renewable energy targets is fundamentally flawed
   1. EPA has mischaracterized and overstated the renewable energy development associated with existing renewable portfolio standards
   2. EPA's methodology for calculating renewable energy goals is flawed
   3. The state renewable goals calculated by EPA are flawed and inconsistent with the assessment and experience of individual states
   4. EPA should more robust data as the baseline for building block 3

C. EPA's alternative approach for calculating renewable energy goals is fundamentally flawed
   1. EPA overstates the technical potential of state renewable resources and calculates growth rates for renewable energy development that are flawed
   2. EPA uses unsubstantiated assumptions on future costs to estimate the market-based potential for state renewable energy development
   3. The alternative methodology produces absurd results as applied to state emission rate goal

D. Building Block 3 Comments related to EPA's NODA
   1. The alternative approach proposed in NODA is flawed
   2. State goal calculation method for Building Blocks 3 and 4

E. EPA did not fully consider transmission issues that impact the feasibility, cost, and timing for developing renewable resources

F. EPA does not fully consider the technical, cost, regulatory, and practical challenges of increasing renewable resources

G. EPA should exclude nuclear energy from state goal calculations

H. Recommendations regarding building block 3.

VIII. Building Block 4 Comments

A. Flaws in EPA's EE Achievability Analysis

1. Base Data Inconsistencies
2. Invalid extrapolations
    a. Relative size of customer classes not comparable
    b. Commercial and industrial opt-out provisions not considered
    c. Customers subject to section 111 of the CAA should be excluded
    d. Average temperatures and electricity consuming devices are not comparable
    e. Temporal considerations
    f. Other options
3. Customer economic challenges
4. Market potential studies
5. States uses as proxies
6. Illustrated example
7. EE growth estimates

B. Cost Estimates

C. Measurement and Accounting

1. Attribution
2. Evaluation, Measurement, and Validation
3. Impacts

D. Ancillary Issues

1. Municipal and Co-operative utilities
2. C&I opt-out / Self-direct provisions
3. Variety of EE sources
4. Cost-effective EE not included in base case
5. Beneficial use
6. Timing

IX. EPA has failed to describe the mechanisms states can use to develop and implement a plan that will reliably demonstrate compliance.

A. Errors and uncertainties in EPA's state goal calculations creates significant uncertainty regarding the actual goal to be met and viability of available compliance options

B. Issues within each building block make implementation unworkable

1. Improvements made through building block 1 cannot be reliably projected or enforced
2. Building block 2 cannot require states to interfere with the economic dispatch or reliable operation of the grid
3. Building blocks 3 and 4 are not enforceable against designated facilities

C. Uncertainties with the state plan development process and design options must be resolved before states can propose implementation plans to EPA

1. EPA's Proposal to Allow State Plans to Include Federally Enforceable Obligations on "Affected Entities" Exceeds EPA's Statutory Authority.
2. EPA's Proposal to Regulate States or State Agencies as "Compliance Entities" Is Inconsistent with the Clean Air Act's Premise of Cooperative Federalism and Raises Serious Enforceability Concerns
3. Uncertainties Affect Plan Development Due to Reliability Issues
4. Uncertainties Regarding Multi-State Plans

D. EPA has overstated the degree of implementation "flexibility" available to states
   1. Significant compliance flexibility will be eliminated if EPA corrects the technical errors associated with building blocks one and two
   2. Potential compliance options referenced by EPA outside of the building blocks do not provide additional "flexibility"
   3. EPA's proposed alternative mass-based program does not provide additional compliance flexibility

E. EPA must not infringe on the statutory authority granted state plan development, including consideration of the remaining useful life of the existing source

F. EPA cannot regulate affected sources under both 111(b) and 111(d)

G. EPA's proposed implementation timeline is unachievable

X. EPA Failed to Conduct An Adequate Reliability Analysis, and Does Not Provide Adequate Time in Its Implementation Schedule to Address Electric Infrastructure Needs

   A. EPA Lacks the Tools and Expertise to Assess Transmission Reliability
   B. AEP and Industry Analyses Demonstrate Real Reliability Concerns
   C. CPP Compliance Plans Are Not Viable without a Regional Transmission Analysis
   D. Interim Goals Incompatible with Transmission Infrastructure Requirements
   E. Assumptions for Renewable Expansion Must Also Consider Transmission Requirements
   F. Transmission Recommendations

XI. Assessment of Regulatory Impact Analysis

   A. Lack of Information on State Compliance Actions
   B. Conflicts Between Results and Purported BSER elements
   C. Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs
   D. Incomplete Assessment of Employment Impacts
   E. Improper Treatment of Energy Efficiency
   F. Improper Use of Social Cost of Carbon

## I. Introduction

On June 2, 2014, the United States Environmental Protection Agency ("EPA") issued a proposal entitled *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule*,[1] (also referred to as the Clean Power Plan or "CPP"). If adopted, the CPP would establish an expansive and unprecedented program to regulate the production, delivery, and use of electricity in the United States. Based on the legal analysis and principles laid out in the proposed CPP, EPA is claiming authority to regulate the electric grid and the use of electricity, in pursuit of greenhouse gas emission reductions, that is virtually unlimited. If upheld by the courts, there is no reason to believe that EPA would be reluctant to extend these legal theories and principles to other source categories, leading to an unprecedented degree of control over the productive capacity of those sources and consumer choices about the use of those products.

However, the Supreme Court has recently stated, in the context of another EPA rulemaking for greenhouse gases, that "When an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' … we typically greet its announcement with a measure of skepticism."[2] Such skepticism is warranted here as well. The statutory authority for this proposal is claimed to reside in a section of the Clean Air Act ("CAA") that has rarely been used and that does not support the breadth of this regulatory proposal. Instead of identifying the degree of emission reduction that can be achieved by "existing sources" that are "designated facilities" within a "source category," as authorized by Congress, EPA instead has identified an "emission rate" that cannot be achieved by the "designated facilities" alone, and that presumes implementation of a multitude of electricity-related activities throughout each individual state, including activities to reduce electricity usage by individual electricity customers. The emission rate is based on an equation that includes not only the generation and emissions from "designated facilities" to which a section 111 standard would apply if those facilities were "new," but also the production of electricity from emitting and non-emitting sources outside the designated source category, and avoided generation attributed to customer end-use efficiency measures. All of these activities are identified as part

[1] 79 Fed. Reg. 34,829 (June 18, 2014).
[2] *UARG v. EPA,* 134 U.S. 2444 (2014) (citations omitted).

of an overall "best system of emission reduction" ("BSER") that is inconsistent with the statute, EPA's own regulations, and its historic implementation of this CAA provision.

EPA uses this equation to establish emission rate targets for individual states to meet through the development of individual state or regional plans. States will not be able to alter the emission rate once EPA finalizes the CPP, and EPA will judge the adequacy of each state's plan against the targets ("state goals") once the proposed rule is finalized. The targets include both "interim" and "final" goals, but the "interim" goals represent 50-90 percent of the required reductions in most states, and average over 60 percent of the final goals. States must complete substantial actions toward a final approved plan within one year after the guidelines are final, and there could be as little as 6 - 18 months between the federal approval of a state plan and the beginning of the first compliance year.

The operating companies of the American Electric Power (AEP) System appreciate the opportunity to submit the attached comments on the CPP. AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states, and will be directly affected by the requirements of the final rule. AEP companies also own the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

## II. Overview of the CPP

On June 23, 2013, President Obama announced a "Climate Action Plan" to address greenhouse gas ("GHG") emissions from a number of different sectors of the economy, which included a specific schedule for the EPA to propose and finalize a GHG program for electric generating units ("EGUs"). The President's plan called for EPA to issue its proposal for EGUs on June 1, 2014. The anticipated time frame for finalizing and implementing the CPP is as follows:

- Proposed CPP published in the *Federal Register* June 18, 2014;
- Public comment period on the proposed CPP ends December 1, 2014;
- Final CPP to be issued by June 1, 2015;
- Individual plans to be submitted by the states by June 30, 2016, but EPA may grant one-year extensions for state plan submittals and two-year extensions for states that commit to develop multi-state regional plans;
- EPA has up to one year to approve state plans, which could occur as early as June 2017, or as late as June 2019 or beyond;
- Under the proposed CPP, the initial compliance period begins January 1, 2020.

The proposed CPP is based on four "building blocks" which EPA uses to calculate proposed state goals that focus on reducing carbon dioxide ("$CO_2$") emission intensity from this sector. The state goals are expressed as pounds of $CO_2$ emissions per net megawatt-hour of electricity ("lbs./MWh net"). The four building blocks and the assumptions used in the calculations in the proposed CPP are as follows:

- Building Block 1: All existing coal plants are assumed to improve their collective average heat rate by 6%, resulting in a corresponding reduction of 6% in the $CO_2$ emission rates for these units.
- Building Block 2: All existing natural gas combined cycle ("NGCC") units (including those currently under construction) are assumed to increase their collective average utilization to at least a 70% capacity factor. The increased energy produced by NGCC units is assumed to displace higher $CO_2$-emitting generation (from coal-, gas-, and oil-fired steam units).
- Building Block 3: All states will implement regionally identified "best practices" to incorporate increasing amounts of renewable energy ("RE") into their generation portfolios, achieving in effect a 13% national renewable portfolio standard ("RPS") by 2030. EPA also assumes the continued operation of existing nuclear units (including nuclear units currently under construction) at a 90% or better capacity factor, and that no additional nuclear units will retire. The goal calculation for states with existing nuclear capacity assumes 6% of the nuclear capacity in the state

displaces carbon-emitting generation. EPA also includes the full amount of any new nuclear capacity currently under construction in the calculation of the emission rate for those affected states.

- Building Block 4: States will implement "best practices" to encourage customers to use energy efficiently ("EE"), achieving incremental savings, presumed to displace up to 1.5% of electricity sales annually and up to 10% by 2030 and thereafter.

EPA also requests comment on a set of alternate less stringent state goals that would require final compliance by 2025 instead of 2030. For the alternate goals, the 'building blocks" assume the following activities:

- Building Block 1: achieve a 4% improvement in heat rate at existing coal units
- Building Block 2: increase utilization of existing NGCC capacity to 65%
- Building Block 3: increase renewable energy to 9.4% of energy sales; and
- Building Block 4: increase EE to 5.2% cumulative energy savings by 2025 and thereafter

EPA relies on all four of these "building blocks" to establish the overall targets for each state. The state goals can generally be expressed by the following formula:

$$\frac{CO_2 \text{ emissions from all affected fossil EGUs (in pounds) + other emissions}}{\text{Generation from (fossil EGUs + 6\% nuclear + renewables}^{3}\text{) + UTO}^{4}\text{ + EE savings (in MWh)}}$$

Using this calculation and output from its Integrated Planning Model (IPM), EPA established an "interim" goal for each state based on full implementation of the changes required under building blocks 1 and 2, and a glide path of incrementally more stringent annual goals based on gradual implementation of the measures required under building blocks 3 and 4, until the "final" goal is achieved in 2030, and maintained in each year thereafter (on a three-year average basis). EPA proposes that the "interim" goals can be met on a 10-year average basis, with annual reporting and corrective measures if states fall behind in their implementation. Because the amount of electricity and emissions from fossil generation in each state vary significantly, as do the capacity and performance of renewable resources, and the applicability and penetration of energy efficiency measures, the goals calculated for each state have a very wide range.

In the 1975 rulemaking finalizing EPA's implementing regulations for §111(d), EPA explained that, "[a]lthough the general principle (application of best adequately demonstrated

[3] Renewable resources do not include existing hydroelectric generation resources. In addition, EPA is unclear on how biomass will be treated under the program.

[4] UTO = Useful Thermal Output associated with combined heat and power facilities.



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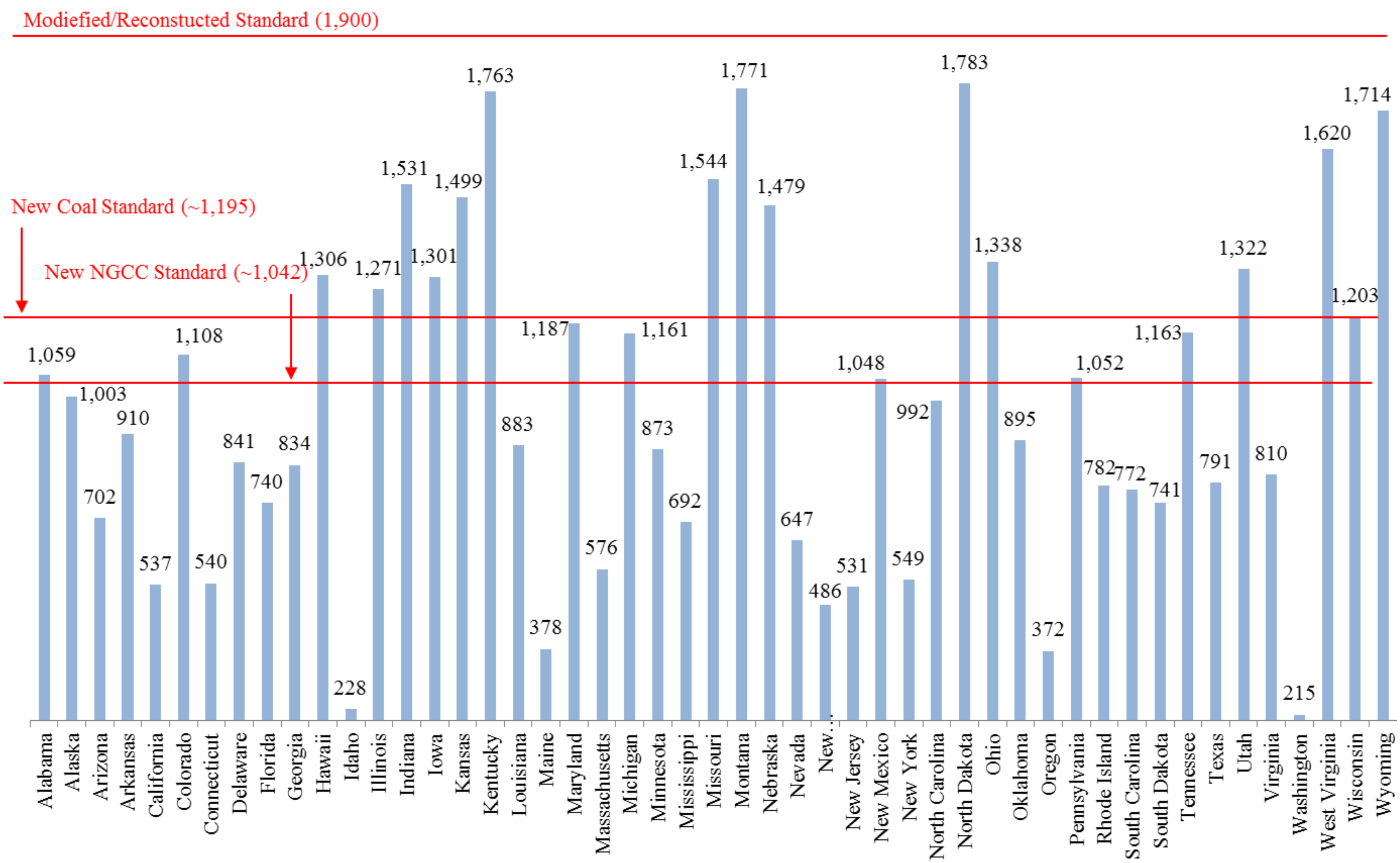
control technology, considering costs) will be the same [under sections 111(b) and 111(d)], the degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources."[5] In EPA's Clean Power Plan, in comparison, approximately half of the states' $CO_2$ emission performance goals are less than the standards for new electric utility boilers.[6] While these state goals are not, themselves, standards of performance, EPA has said that "each state will determine, and include in its plan, emission performance levels for its affected EGUs that are equivalent to the state-specific $CO_2$ goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal."[7] Consequently, for over half of the United States, EPA's Clean Power Plan would impose more stringent emission reduction requirements for existing EGUs than the performance standards EPA is proposing for new EGUs. A comparison of the final state goals to the standards EPA has proposed for "new" fossil-fueled electric generating units is shown below.

[5] 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).
[6] *See* Proposed Subpart UUUU, Table 1.
[7] 79 Fed. Reg. at 34,837.

**Proposed Existing Source 111(d) Final Goals vs. New Source 111(b) Standards (lb CO2/MWh net)**



For the states in which the AEP companies operate, the interim and final goals, and the relative contribution of each building block to the ultimate reductions are summarized in the table below.

**State Goals and Relative Reductions Contributed by Each Building Block**

| | 2012 Average State Coal Emission Rate | 2012 Average State NGCC Emission Rate | Interim Goal | Final Goal | Block 1 | Block 2 | Block 3 | Block 4 |
|---|---|---|---|---|---|---|---|---|
| | (lb. $CO_2$ / MWh net) | | | | % of 2030 Rate Reduction | | | |
| Arkansas | 2,276 | 827 | 968 | 910 | 9% | 60% | 14% | 17% |
| Indiana | 2,158 | 914 | 1,607 | 1,531 | 24% | 11% | 17% | 48% |
| Kentucky | 2,166 | n/a | 1,844 | 1,763 | 29% | 15% | 8% | 48% |
| Louisiana | 2,323 | 766 | 948 | 883 | 7% | 54% | 16% | 22% |
| Michigan | 2,255 | 810 | 1,227 | 1,161 | 13% | 32% | 19% | 37% |
| Ohio | 2,216 | 963 | 1,452 | 1,338 | 16% | 14% | 32% | 38% |
| Oklahoma | 2,305 | 891 | 931 | 895 | 9% | 50% | 21% | 20% |
| Tennessee | 2,244 | 813 | 1,254 | 1,163 | 10% | 10% | 51% | 29% |
| Texas | 2,239 | 837 | 853 | 791 | 8% | 44% | 28% | 20% |
| Virginia | 2,268 | 903 | 884 | 810 | 6% | 33% | 31% | 24% |
| West Virginia | 2,056 | n/a | 1,748 | 1,620 | 27% | 0% | 52% | 21% |

The CPP proposal is wholly different from any prior emission limitation, standard, or guideline developed by EPA under the CAA. The assumptions that EPA uses to develop state goals supersede the authority granted to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, contain significant and fundamental technical flaws regarding the nature and operation of electricity generators and the electricity grid, and intrude upon authority reserved to the states. The proposal also is contrary to the express requirements of Section 111 of the CAA, and EPA's own regulations, in several significant respects.

The following comments outline the requirements for rulemaking under section 111(d), and the principles that in the past have guided, and should in this case guide, EPA's determination of the "best system of emission reduction" ("BSER") for existing fossil fuel-fired steam electric- and combustion turbine-based generating units. They then examine the individual building blocks and point out ways in which EPA's determinations are inconsistent with the physical and practical limitations that affect the electricity system, are based on inaccurate information, contain fundamental errors in methodology, or are otherwise arbitrary and capricious. Finally, the comments examine the challenges states will face in attempting to implement the requirements of the proposal, address the reliability concerns raised by the proposal, and analyze the shortcomings in EPA's cost-benefit analysis. The comments conclude with suggestions for implementing a practical program to achieve $CO_2$ emission reductions from existing fossil fuel-fired electric generating units that is consistent with the CAA and acknowledges the primacy of the states in implementing such programs.

## III. Basis for Rulemaking Under Section 111(d)

Ultimately, EPA's proposed CPP must be evaluated based on the authority granted to the agency by Congress. Under section 111(d) of the CAA, the Administrator of EPA is authorized to "prescribe regulations which shall establish a *procedure* similar to that provided by section [110] of this title."[8] Section 110 is the section under which each state develops its state implementation plan ("SIP") to assure attainment and maintenance of the national ambient air quality standards ("NAAQS"). Unlike section 110, however, section 111 does not contain any specific timelines for the development of EPA's guidelines, the submission of state plans, or the time within which EPA must review and approve or disapprove a state plan. In 1975 EPA adopted a set of regulations setting forth procedures to govern how each state develops a plan that establishes standards of performance for existing sources covering certain air pollutants that would be subject to standards under section 111(b) of the CAA if such existing sources were "new sources" as defined in section 111(a)(2) of the CAA.[9] Those regulations are set forth in 40 CFR Part 60, Subpart B, and are called the section 111(d) "implementing regulations" by EPA. EPA's implementing regulations provide certain default time periods for submission, review, and approval of state plans, but EPA has proposed alternate time periods for these activities in the CPP.

The implementing regulations require the Administrator to publish a draft guideline document, at the same time or after she proposes standards of performance for new sources in the category under section 111(b). The guideline document must contain "information pertinent to control of the designated pollutant from designated facilities." After EPA receives public comments and issues the new source standards in final form, EPA issues the final guideline document along with other information the Administrator thinks may contribute to the

[8] 42 U.S.C §7411(d) emphasis added.
[9] 42 U.S.C. §7411(d).

development of state plans.[10] States then develop and submit their plans for review by the Administrator.

The Administrator issued proposed standards for new EGUs in January of 2014, and in June 2014 issued a proposed standard for modified and reconstructed EGUs (which are considered "new sources" under section 111(a)(2) of the CAA) concurrently with the proposed existing source guideline document. The standards for new, modified, and reconstructed sources are specified emission rates for specific types of individual generating units, the "designated facilities" mentioned in 40 CFR § 60.22. In contrast, EPA's proposal for existing sources under section 111(d) goes far beyond the sources covered under its proposed "new source" standards, and fails to acknowledge the governing law that assigns states the responsibility for developing plans and grants states substantial discretion to vary from the guidelines under appropriate circumstances. In particular, EPA's interpretation of the phrase "best system of emission reduction" for purposes of this proposal departs in several significant respects from the plain language of section 111 of the CAA.

## IV. EPA's Interpretation of the "Best System of Emission Reduction" Is Fatally Flawed

A fatal defect in EPA's CPP is the proposal's dependence upon an abstract, out-of-context interpretation of "system" in the phrase "best system of emission reduction" in the section 111 definition of "standard of performance." EPA's unprecedented interpretation of the word "system" in the "standard of performance" definition is disassociated from, and in conflict with, the interlinked CAA definitions of "stationary source," "existing source," "emission limitation," and "performance standard," and with the legislative history of section 111. It is also in conflict with EPA regulations that implement section 111, and at odds with EPA's interpretation and application of section 111 throughout its 44-year history.

Another fatal defect in EPA's proposal is the dubious way it attempts to ignore the phrase "standards of performance for any existing source" in section 111(d), by reinterpreting the word "for." In Humpty Dumpty fashion,[11] EPA concludes that a performance standard "for" an existing source may apply to "other entities whose actions would reduce generation, and thus

[10] 40 CFR §60.22.

[11] "When *I* use a word, Humpty Dumpty said, in a rather scornful tone, "it means just what I choose it to mean – neither more nor less."
"The question is," said Alice, "whether you *can* make words mean so many different things." *Through the Looking Glass, available at* www.gutenberg.org/files/12/12-h/12-h.htm.

emissions" from the existing source. "For any existing source" is not the same thing as "for other entities." If it were, the resulting authority to mandate reduced production from existing sources and replace that production with actions by "other entities," heretofore hidden in section 111(d), would greatly expand EPA's powers over the American economy.

EPA's flawed, out-of-context interpretations of "system" and "for" lead to proposed "emission guidelines" and "state goals" that necessitate command and control of the performance of "entities" that are outside the affected EGU source category, and contrary to the plain language of the statute. EPA's proposed emission guidelines rely on restrictions that would affect the behavior and obligations of electricity consumers, balancing authorities, electricity distribution companies with no generating capacity, natural gas pipeline suppliers, and the states themselves. Rather than reflecting the degree of emission limitation achievable by applying a demonstrated technology-based (or work practice) system of emission reduction to the affected EGU, as the statute plainly directs, the proposal requires a reduction in the hours of operation and/or rate of production (or complete shutdown) of affected EGUs, a result contrary to the text and structure of the statute, and that could not have been imaginable to the Congresses that enacted and amended the CAA in 1970, 1977, and 1990. For all of these reasons, as explained below, EPA's Proposed CPP is contrary to statute, contrary to EPA's own regulations, unworkable, and unlawful.

### A. EPA's Proposed Action Is Unlawful and Not Entitled To Deference, Because It Conflicts In Multiple Ways With The CAA's Unambiguous Text

It is axiomatic that an administrative agency may not write, or re-write, its own enabling legislation. EPA is "a creature of statute," and has "only those authorities conferred upon it by Congress."[12] Since Congress is the source of an agency's powers, the absence of express Congressional constraint does not imply a delegation of legislative rulemaking authority to the agency. Congress does not delegate to an agency every authority that it does not explicitly withhold or prohibit.

In construing an agency's enabling legislation, when "Congress has directly spoken to the precise question at issue[,]" and "the intent of Congress is clear, that is the end of the matter; for

[12] *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001); *see also Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988) ("It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress.").

the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress."[13] As the Supreme Court held in its most recent CAA decision, it is a "core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate."[14] Also, "[a] court's prior judicial construction of a statute trumps an agency construction ... if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion."[15]

It is for the reviewing court to determine, "employing the traditional tools of statutory construction," whether or not the intent of Congress is clear.[16] Determining whether a given word or phrase is ambiguous, moreover, typically requires a court to review more than just the word or phrase itself. "In making the threshold determination under *Chevron*, 'a reviewing court should not confine itself to examining a particular statutory provision in isolation.'"[17] Instead, the court must review the phrase "in context,"[18] with an eye to its "'place in the overall statutory scheme.'"[19] "Thus, an agency interpretation that is 'inconsisten[t] with the design and structure of the statute as a whole[ ]' ... does not merit deference."[20]

1. EPA's broad interpretation of "best system of emission reduction" conflicts with the narrower definitions Congress gave related terms in the Act.

EPA's BSER determination is based on the mistaken presumption that "the CAA does not define the term 'system,'" and that "the context in which 'standard of performance' ... is found does not add additional constraints."[21] In fact, the CAA contains several relevant definitions that require EPA to construe "system of emission reduction" in a more narrow and specific fashion.

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[13] *Chevron, U.S.A., Inc. v. NRDC, Inc.*, 467 U.S. 837, 842-843, 104 S.Ct. 2778 (1984).
[14] *Util. Air Regulatory Grp. v. EPA*, 134 S.Ct. 2427, 2446 (2014).
[15] *Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 982, 125 S.Ct. 2688, 2700 (2005).
[16] *Chevron*, 467 U.S. at 843 n. 9.
[17] *Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 666, 127 S.Ct. 2518, 2534 (2007), quoting *FDA* v. *Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 132, 120 S. Ct. 1291 (2000).
[18] *Brown & Williamson Tobacco Corp.*, 529 U.S. at 132 (citation omitted).
[19] *Id.* at 133, *quoting Davis v. Michigan Dept. of Treasury,* 489 U.S. 803, 809, 109 S. Ct. 1500 (1989). *See also Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 471, 121 S.Ct. 903 (2001) (indicating that a provision of the CAA must be "interpreted in its statutory and historical context and with appreciation for its importance to the CAA as a whole").
[20] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2442, *quoting University of Tex. Southwestern Medical Center v. Nassar*, 570 U.S. ___, ___, 133 S. Ct. 2517, 186 L. Ed. 2d 503 (2013).
[21] Legal Memorandum at 51-52.

Under section 111(d)(1), EPA is required to prescribe by regulation procedures under which states will develop and submit plans that establish "standards of performance" for certain existing sources.[22] "Standard of performance" is defined to mean "a standard for emissions of air pollutants which reflects the degree of *emission limitation* achievable through the application of the best *system* of *emission reduction* which the Administrator determines has been adequately demonstrated."[23] It is also defined, in section 302, to mean "a requirement of continuous emission reduction ...."[24] "Emission limitation" is not defined in section 111. But it is defined in section 302 to mean "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous *emission reduction*, and any design, equipment, work practice or operational standard promulgated under this chapter."[25] Congress directed that the CAA's section 302 definitions apply whenever "used in this chapter," including when they are part of the more specific definitions in section 111. Together, these definitions require any "emission limitation" or "standard of performance" to limit emissions on a "continuous" basis. These definitions make two more things clear:

- Congress understood an "emission limitation" to be the means to accomplish "emission reduction."

and

- Congress understood "emission limitation" to mean a continuous quantity-, rate-, or concentration-based limit on a relevant pollutant emitted by a stationary source; or a design standard, equipment standard, work practice standard, or operational standard for control of emissions from a stationary source.

The general provisions in section 302 also contain a definition for a term closely related to "system of emission reduction." The CAA defines "means of emission limitation" to mean "a system of continuous emission reduction (including *the use of specific technology* or *fuels with specified pollution characteristics*)."[26] And, section 111 includes a definition for "technological system of continuous emission reduction," which it defines as:

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[22] 42 U.S.C. § 7411(d)(1).
[23] 42 U.S.C. § 7411(a)(1) (emphasis added).
[24] 42 U.S.C. § 7602(l).
[25] 42 U.S.C. § 7602(k) (emphasis added).
[26] 42 U.S.C. § 7601(m) (emphasis added).

- a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or
- a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.[27]

As shown above, there is no meaningful difference between the phrases "system of emission reduction" and "system of continuous emission reduction." Based on the clear language of the CAA, then, there is no doubt about the kinds of things that Congress considered to be "systems of emission reduction." Importantly, they are all measures that would be taken at individual units and directly reduce emissions from those units on a continuous basis.[28]

Given the clear direction provided by Congress, EPA may not simply pick a broad definition out of the dictionary and say that its choice is entitled to deference; the agency also has to look to "contextual indications" to determine whether that definition is a "permissible interpretation."[29] EPA's second, third, and fourth building blocks, which would collectively reduce utilization of certain affected EGUs, but increase utilization of others, are nothing like the systems of emission reduction listed in the CAA or discussed in the legislative history. Rather than changing a regulated source's fuel, production process, or method of operation, or installing pollution controls at the source, EPA's building blocks would require the use of a different *source* altogether. Nothing in the CAA's definitions of "system of continuous emission reduction" or "technological system of continuous emission reduction" supports an interpretation of "system" that includes creating a preference for the operation of one type of source over another, or dictates that wholly unregulated sources should be encouraged not to retire or to be constructed in order to replace the output from sources EPA has listed within a section 111 source category. Indeed, section 111(d)'s requirement that EPA allow states to adjust compliance obligations and schedules in order to take into consideration, among other factors, the remaining useful life of existing source, is a clear indication that Congress did not mean for EPA to require wholesale changes in capital stock as a means of reducing emissions. The goals of the CAA incorporate both protecting and enhancing air quality, and promoting the productive

[27] 42 U.S.C. § 7411(a)(7) (emphasis added).
[28] Section 111 provides additional flexibility by allowing the Administrator and the states, in appropriate circumstances, to establish work practice standards in lieu of specific emission limitations, or to adopt market-based emission allowance programs. 42 U.S.C. § 7411(a)(1), (k).
[29] *MCI Telecomms. Corp. v. AT&T Co.*, 512 U.S. 218, 226, 114 S.Ct. 2223, 2229 (1994).

capacity of the Nation's population.[30] Because the proposed interpretation of "system of emission reduction" that underlies EPA's Clean Power Plan is inconsistent with Congress's intentions for that term, as illuminated by Congress's definitions of related terms in the Act, EPA's interpretation is unreasonable and unlawful.

2. EPA's interpretation of "system of emission reduction" to include reduced utilization is incongruous with the Act's requirement that any such system be "adequately demonstrated."

EPA's assertion that "system of emission reduction" can be interpreted to include reduced utilization is also contrary to the CAA's requirement that any such system be "adequately demonstrated." Section 111(a)(1) defines "standard of performance" to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which … the Administrator determines has been *adequately demonstrated*."[31] The D.C. Circuit Court of Appeals has explained that Congress added the requirement that any "best system of emission reduction" be "adequately demonstrated" in order to ensure that the chosen emission control technology would be commercially available:

> The language in section 111 was the result of a Conference Committee compromise, and did not incorporate the language of either the House or Senate bills. The House bill would have provided that "the Secretary ... [give] appropriate consideration to technological and economic feasibility," while the Senate would have required that standards reflect "the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.
>
> The Senate Report made clear that it did not intend that the technology "must be in actual routine use somewhere." The essential question was rather whether the technology would be available for installation in new plants. The House Report also refers to "available" technology. Its caution that "in order to be considered 'available' the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution" merely reflects the final language adopted, that it must be "adequately demonstrated" that there will be "available technology.[32]

The court has explained that "where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated … on mere speculation or

[30] 42 U.S.C. §7401(b)(1).
[31] 42 U.S.C. §7411(a)(1).
[32] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

conjecture, but EPA may compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries."[33] In 1973, the D.C. Circuit also held that "[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[34]

These 1973 and 1999 opinions reflect the D.C. Circuit's assumption that a "best system of emission reduction" would be a technological system of emission reduction, even though section 111 of the 1970 CAA and the 1990 CAA did not include the word "technological" at the times the court issued those opinions. Equally importantly, however, they are incompatible with the concept of reduced utilization as a "system of emission reduction." Reduced utilization does not need to be purchased. EPA would not need to determine whether reduced utilization was "reliable" or "efficient." EPA would never need to determine whether reduced utilization had performed well in other industries. In short, EPA would never need to determine whether reduced utilization was "adequately demonstrated." Interpreting "system of emission reduction" to include reduced utilization would render the requirement to determine whether a potential BSER was "adequately demonstrated" a nullity. Thus, that interpretation must be rejected; courts are " 'reluctant to treat statutory terms as surplusage' …[,] [and] especially unwilling to do so when the term occupies so pivotal a place in the statutory scheme … ."[35]

The Act's requirement that any "best system of emission reduction" be "adequately demonstrated" conclusively proves that reduced utilization was not within Congress's conception of a "system of emission reduction." EPA's proposal to accept reduced utilization as a "building block" of BSER is contrary to the statute and, therefore, is unreasonable and unlawful.

3. EPA's broad interpretation of "best system of emission reduction" conflicts with Congressional intent, as illuminated by legislative history

A more narrow and specific understanding of "system of emission reduction" is not only evident from the language and structure of the CAA; it is, unsurprisingly, reflected in the legislative history as well. The committee reports for the bills that ultimately became the 1970

[33] *Lignite Energy Council v. U.S. E.P.A.*, 198 F.3d 930, 933-934 (D.C. Cir. 1999).
[34] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-434 (D.C. Cir. 1973).
[35] *Duncan v. Walker*, 533 U.S. 167, 174, 121 S.Ct. 2120, 2125 (2001).

CAA Amendments suggest that Congress understood a "system of emission reduction" to be something that would be installed in, or otherwise designed into, new sources at the time of construction. The House Committee on Interstate and Foreign Commerce, reporting H.R. 17255, described its proposed Section 112 as requiring that sources be "designed and equipped to prevent and control ... emissions to the fullest extent compatible with the available *technology* and economic feasibility as determined by the Secretary."[36] And, the Senate Committee on Public Works' report for the Senate bill, S. 4358, explained that "'standards of performance' ... refers to the degree of emission control which can be achieved through *process changes, operation changes, direct emission control*, or other methods."[37] Ultimately, these proposals were combined in conference committee to form section 111. A "Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970," inserted into the Congressional Record, described the NSPS regulations as requiring "new major industry plants ... [to] achieve a standard of emission performance based on the *latest available control technology, processes, operating methods*, and other alternatives"[38] – a list of "systems of emission reduction" substantially similar to that currently found in the Act. Although this legislative history refers to section 111(b), and notes 111(d), both sections rely on the same definition of "standard of performance" set forth in section 111(a)(1).

In 1990, Congress amended the definition of "standard of performance" once more to return it to something closely resembling its original 1970 form.[39] The Report of the Committee on Energy and Commerce of the U.S. House of Representatives explained that the purpose of the amendment was to "repeal[ ] the 'percent reduction' requirement" added in the 1977 CAA amendments, which EPA had interpreted to require new coal-fired power plants to "reduce emissions by a fixed percentage" and "effectively require[ ] the installation of scrubbers on all new plants."[40] Congress instead ordered EPA to "promulgate revised NSPS within three years" that would result in the same emissions, but "give units the flexibility to meet the emission rates established under the new standards through whatever combination of *fuels and emission*

[36] H.R. Rep. No. 91-1146, at 9 (1970) (emphasis added).
[37] S. Rep. No. 91-1196, at 16 (1970) (emphasis added).
[38] 116 Cong. Rec. 42,383 (1970) (emphasis added).
[39] *See* CAA Amendments of 1990, Pub. L. 101-549, 104 Stat. 2399, § 402 (1990).
[40] H.R. Rep. 101-490 at 3413 (1990).

*controls* the units choose."[41] Thus, a review of the legislative history for the 1977 and 1990 Clean Air Amendments reinforces that Congress intended "standard of performance" to mean an emission limitation that would be accomplished at individual units through the use of low-emitting fuels, process changes, operation changes, or direct emission controls. EPA's proposed, broad interpretation of "system" – "[a] set of things working together as part of a mechanism or interconnecting network"[42] – is inconsistent with both the examples of "systems of emission reduction" found in the Act and the examples of "systems" found in the legislative history.

EPA argues that "Congress has recognized reduced utilization in several contexts as a method to reduce air pollution."[43] More to the point, EPA argues that Congress has recognized "closing plants [as] a method of reduction pollution," and that the difference between closing plants and reduced utilization is just a matter of degree.[44] But, the only example EPA provides that is directly on point is a provision in the 1970 version of section 110 that *explicitly* authorized the imposition of "transportation controls."[45] That provision, which is no longer in the statute, does not support EPA's position, because nothing in section 111 explicitly authorizes the use of reduced utilization as a system of emission reduction. EPA's other examples – a provision in section 110 allowing for temporary emergency suspensions to prevent plant closures,[46] and one Senator's statement (in the legislative history for the 1970 amendments) that section 112 emission limitations may be set at a level that some plants cannot meet[47] – are simply not analogous. Congress's acknowledgment that the imposition of emission limitations under sections 110 or 112 could lead to the closing of some sources is far from a "recognition that closing plants is a method of reducing pollution"[48] or authorization to require reduced utilization of any existing sources as a section 111 performance standard. In other words, the fact that Congress acknowledged the possibility that some CAA requirements could *result* in plant closures does not demonstrate that Congress authorized EPA to *pursue* plant closures as a method of pollution control for existing sources under section 111. To the contrary – section 111 explicitly requires EPA (if it crafts a federal implementation plan for a state) and authorizes the

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[41] *Id.* (emphasis added).
[42] 79 Fed. Reg. at 34,885 (quoting Oxford Dictionary of English (3rd ed.)).
[43] Legal Memorandum at 82.
[44] *See* Legal Memorandum at 84.
[45] Legal Memorandum at 83 n. 64.
[46] *See* 42 U.S.C. § 7410.(g)(1).
[47] *See* Legal Memorandum at 84 n. 66.
[48] Legal Memorandum at 84.

states (if they craft their own implementation plans) "to take into consideration ... the remaining useful life of the existing source to which [a standard of performance] applies."[49] The fact that some sources have *chosen* to reduce their generation to comply with the requirements of various cap-and-trade programs, including the CAA's Acid Rain program, EPA's NOx SIP Call, or EPA's Clean Air Interstate Rule,[50] does not mean that Congress intended EPA to select reduced utilization as a form of section 111, technology-based pollution control, particularly in light of the command that the Administrator allow states to consider the remaining useful life of a source in developing a section 111(d) plan.[51] As is demonstrated below, in each prior determination under section 111 for new or existing sources, including EPA's recent proposals to regulate $CO_2$ from new EGUs, EPA's analysis has focused on technologies and operating practices that can be applied at the source and reduce emissions while the source is operating at its maximum capacity. Not once in the history of the CAA has EPA determined that emission reductions should be based on limiting production or prematurely retiring units with substantial remaining useful life. Such action is not authorized by section 111, and EPA's attempt to compel such actions here should be rejected.

4. If EPA's BSER building blocks are a "system," they cannot be severable.

In EPA's CPP, the agency argues that its combination of multiple measures into one "system of emission reduction" is justified by the "broad" definition of a "system" as a "set of things working together as parts of a mechanism or interconnecting network."[52] This characterization of EPA's BSER suggests that the building blocks are like the gears of a watch – interdependent. On the other hand, EPA has asserted that its "proposed findings of the BSER with respect to the various building blocks" are "severable," such that any one or more of its building blocks could stand on its own if a court were to find that the other building blocks are unlawful.[53] EPA similarly asserts that each block "independently" meets the necessary criteria for inclusion in EPA's chosen BSER:

> [E]ach of the four building blocks is a proven way to support either improvements in emissions rates at affected EGUs or reductions in EGU mass emissions; each is in

[49] 42 U.S.C. § 7411(d)(1).
[50] Legal Memorandum at 84-85.
[51] 42 U.S.C. § 7411(d)(1).
[52] 79 Fed. Reg. at 34,885 (quoting *Oxford Dictionary of English* (3rd ed.)).
[53] 79 Fed. Reg. at 34,892.

> widespread use *and is independently capable of supporting significant $CO_2$ reductions from affected EGUs*, either on an emission rate or mass-emissions basis, at a reasonable cost consistent with ensuring system reliability.[54]

These two positions are incompatible, and neither entirely aligns with EPA's description of the four building blocks that make up its proposed BSER.

EPA's BSER analysis shows that two of the building blocks are somewhat dependent on each other. EPA has noted there could be a "rebound effect" if building block 1 were "applied in isolation."[55] Heat rate improvements at coal-fired EGUs could make those generating units more competitive, resulting in their greater use, "absent other incentives to reduce generation and $CO_2$ emissions from coal-fired EGUs."[56] According to EPA, building block 2 (re-dispatch) provides the necessary incentive to reduce generation from coal-fired EGUs. Thus, building blocks 1 and 2 are interrelated. A determination that building block 2 is unlawful would require EPA to reconsider its BSER determination in its entirety, or at least the inclusion of building block 1 as a component of BSER.

On the other hand, EPA makes no effort to demonstrate that building blocks 3 and 4 are "interconnected" with building blocks 1 and 2, so as to make the combination of all four measures a "system."[57] EPA suggests that the four building blocks are a system "in light of the integrated nature of the electricity grid."[58] But, it is the building blocks, not the regulated source category, that must be interconnected under EPA's proposed new definition of "system." And, as noted above, EPA repeatedly argues that "the building blocks can be implemented independently of one another," which suggests they are not really a "system" at all.[59] A multiplicity of independent, free-standing elements cannot be a "system" of emission reduction under any reasonable interpretation of that term.

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[54] *Id.* at 34,878 (emphasis added).
[55] 79 Fed. Reg. at 34,882.
[56] *Id.*
[57] EPA has suggested in a recent notice of data availability, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units,* Notice of Data Availability, 79 Fed. Reg. 64,543 (October 30, 2014) (hereinafter referred to as the "NODA"), that increased use of renewable energy resources and energy efficiency measures should be used to "reduce generation, and therefore emissions, from affected fossil fuel-fired generation," and therefore alter and make more stringent the individual state emission rate goals. 79 Fed. Reg. at 64,548. But this conclusion is at odds with the actual operation of the electricity system, which simply responds to load with the most economic available resources that can supply that load, and does not make any other distinctions based on the characteristics of the supply-side resources.
[58] Legal Memorandum at 50; *see also id.* at 54.
[59] 79 Fed. Reg. at 34,895.

In sum, EPA's argument that its BSER components are severable is fundamentally incompatible with its argument that its BSER components combine to form a "system of emission reduction." Either the building blocks "work[ ] together as parts of a mechanism or interconnecting network"[60] or they are severable, but they cannot be both. If EPA finalizes its new approach to determining BSER, it must relinquish its argument that its BSER components are severable. Any finding that a building block is unlawful or invalid will require a reconsideration of the BSER determination as a whole.

### B. EPA's Interpretations Of Section 111(d) Are Unreasonable, Arbitrary, and Capricious, And Are Not Entitled To Deference

"[W]hen an agency-administered statute is ambiguous with respect to what it prescribes, [courts will presume] Congress has empowered the agency to resolve the ambiguity."[61] In such instances, courts will defer to an agency's "permissible construction of the statute."[62] The agency's interpretation must be "reasonable," however.[63] Even where Congress has explicitly directed the agency to promulgate rules, courts will not give "[s]uch legislative regulations ... controlling weight [if] they are arbitrary, capricious, or manifestly contrary to the statute."[64] Courts will not defer when "the statute simply will not bear the meaning the [agency] has adopted."[65] For example, "[t]he EPA may not construe [a] statute in a way that completely nullifies textually applicable provisions meant to limit its discretion."[66]

In weighing an agency's interpretation, the court "must be guided to a degree by common sense as to the manner in which Congress is likely to delegate a policy decision of [significant] economic and political magnitude to an administrative agency."[67] Reviewing courts "expect Congress to speak clearly if it wishes to assign an agency decisions of vast 'economic and

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[60] *Id.* at 34,885 (citation omitted).
[61] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2439.
[62] *Chevron*, 467 U.S. at 843.
[63] *United States v. Mead Corp.*, 533 U.S. 218, 229, 121 S.Ct. 2164, 2172 (2001).
[64] *Chevron*, 467 U.S. at 844. *See also Mead Corp.*, 533 U.S. at 229 ("We have recognized a very good indicator of delegation meriting Chevron treatment in express congressional authorizations to engage in the process of rulemaking or adjudication that produces regulations or rulings for which deference is claimed.").
[65] *Pittston Coal Grp. v. Sebben*, 488 U.S. 105, 113, 109 S.Ct. 414, 420 (1988). *See also MCI Telecomms. Corp. v. AT&T Co.*, 512 U.S. 218, 245, 114 S.Ct. 2223, 2239 (1994) (stating, "an agency's interpretation of a statute is not entitled to deference when it goes beyond the meaning that the statute can bear").
[66] *Whitman*, 531 U.S. at 485.
[67] *Brown & Williamson Tobacco Corp.*, 529 U.S. at 133.

political significance.'"[68] Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes."[69] An agency interpretation that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization" will be rejected as unreasonable.[70]

1. EPA's proposal represents a significant self-expansion of EPA authority without Congressional permission or approval.

An agency's interpretation of its authorizing statute cannot be based on presumed delegation of legislative authority. But that is precisely what EPA's interpretation of the "best system of emission reduction" does. EPA finds in the statute such unbounded discretion, that it presumes the agency itself can write the outer limits on its own authority. EPA's plan stretches the scope of its authority under section 111(d) far beyond anything Congress has expressly delegated to the agency.

If "system of emission reduction" meant what EPA says it means section 111 would be a standardless and, thus, unconstitutional delegation of legislative power from Congress to EPA. Article I, Section 1 of the United States Constitution vests "all legislative Powers herein granted ... in a Congress of the United States." Because this text, by its own terms, actually permits no delegation of legislative powers, when Congress does confer legislative authority upon agencies, Congress must "lay down ... an intelligible principle to which the person or body authorized to [act] is directed to perform."[71] The Supreme Court has twice invoked the nondelegation doctrine to invalidate Congressional acts lacking any intelligible principle to guide executive discretion.[72]

As noted constitutional scholar Cass Sunstein explained, however, the nondelegation doctrine has evolved over time into a doctrine of statutory interpretation that evinces skepticism at overbroad claims of agency authority:

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[68] *Util. Air Regulatory Grp.*, 134 S.Ct. at ___(2014), citing *Brown & Williamson*, 529 U.S., at 159, and *MCI Telecommunications Corp.*, 512 U.S. at 231; *International Union Dept., AFL-CIO v. American Petroleum Institute*, 448 U.S. 607, 645-646 (1980) (plurality opinion).
[69] *Whitman*, 531 U.S. at 468, citing *MCI Telecommunications Corp.*, 512 U.S. at 231 (1994); *Brown & Williamson Tobacco Corp.*, 529 U.S. at 159-160.
[70] *Util. Air Regulatory Grp.*, 134 S.Ct. at 2444.
[71] *J.W. Hampton, Jr. & Co. v. United States*, 276 U.S. 394, 409, 72 L.Ed. 624, 48 S.Ct. 348 (1928) (emphasis added).
[72] *See Panama Refining Co. v. Ryan*, 293 U.S. 388, 405, 79 L.Ed. 446, 55 S.Ct. 241 (1935); *A.L.A. Schecter Poultry Corp. v. United States*, 295 U.S. 495, 537-542, 79 L.Ed. 1570, 55 S.Ct. 837 (1935).

> Federal courts commonly vindicate not a general nondelegation doctrine, but a series of more specific and smaller, though quite important, nondelegation doctrines. Rather than invalidating federal legislation as excessively open-ended, courts hold that federal administrative agencies may not engage in certain activities unless and until Congress has expressly authorized them to do so. *The relevant choices must be made legislatively rather than bureaucratically*.[73]

EPA's current proposal is a prime example of an agency seizing upon an undefined statutory term to make unprecedented legislative policy choices with enormous ramifications for the national economy – choices only properly made by Congress.

Professor Sunstein's above-quoted analysis in *Nondelegation Canons* proved prescient. The following year, in *Whitman v. Am. Trucking Assns.*,[74] the Supreme Court confronted a nondelegation challenge to section 109(b) of the CAA, which requires EPA to promulgate national ambient air quality standards (NAAQS) for various air pollutants. Although the Supreme Court in *American Trucking* rejected a nondelegation challenge to section 109(b) in that case, which had previously succeeded in the D.C. Circuit, the Supreme Court expressly cautioned that "Congress ... does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions -- it does not, one might say, hide elephants in mouseholes."[75] The Supreme Court also noted that Congress "must provide substantial guidance on setting air standards that affect the entire national economy."[76]

The so-called elephants-in-mouseholes doctrine, first expressly announced in those terms in *American Trucking*, "is thus one instance of what Cass Sunstein has dubbed 'nondelegation canons.'"[77] Under this doctrine, which has been applied in other contexts without express reference to elephants or mouseholes,[78] an agency cannot rely upon "vague terms or ancillary

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[73] Cass Sunstein, *Nondelegation Canons*, 67 U. Chi. L. Rev. 315, 315-316 (Spring 2000) (emphasis added).
[74] 531 U.S. 457, 149 L.Ed.2d 1, 121 S.Ct. 903 (2001)
[75] *Whitman*, 531 U.S. at 468.
[76] *Id.* at 475.
[77] Jacob Loshin & Aaron Nielson, *Hiding Nondelegation in Mouseholes*, 62 ADMIN. L. REV. 19 (Winter 2010) (citing Sunstein, *Nondelegation Canons*, *supra*).
[78] *See*, *e.g.*, *MCI Telecommunications Corp. v. American Telephone & Telegraph Co.*, 512 U.S. 218, 231, 129 L.Ed.2d 182, 114 S.Ct. 2223 (1994) (Scalia, J., writing that "[i]t is highly unlikely that Congress would leave the determination of whether an industry will be entirely, or even substantially, rate-regulated to agency discretion -- and even more unlikely that it would achieve that through such a subtle device as permission to 'modify' rate-filing requirements.") *See also FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133, 146 L.Ed.2d 121, 120 S.Ct. 1291 (2000) (Supreme Court holding that the Food and Drug Administration, pursuant to its authority to regulate "drugs" and "devices," could not regulate tobacco, saying "we must be guided to a degree by common sense as to the manner in which Congress is likely to delegate a policy decision of such economic and political magnitude to an administrative agency.")

provisions" in a statute (the mousehole) to alter "the fundamental details of a regulatory scheme" (the elephant).

The Supreme Court most recently revisited this doctrine in its 2014 decision in *UARG v. EPA*. In that opinion, the Court held that EPA is neither required, nor permitted, to require PSD or Title V permits based on a stationary source's GHG emissions.[79] In particular, the Court held that EPA could not reasonably interpret the term "air pollutant" in the context of the permitting triggers for the PSD and Title V programs to include greenhouse gases, because such an interpretation would overwhelmingly expand the scope of both programs:

> The fact that EPA's greenhouse-gas-inclusive interpretation of the PSD and Title V triggers would place plainly excessive demands on limited governmental resources is alone a good reason for rejecting it; but that is not the only reason. EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. When an agency claims to discover in a long-extant statute an unheralded power to regulate "a significant portion of the American economy," we typically greet its announcement with a measure of skepticism.[80]

Yet that is precisely what EPA proposes to do here. Relying upon an abstract and out-of-context interpretation of the term "system" in section 111(a)(1) of the Act, which it defines broadly (and unhelpfully) to mean "a set of things working together as parts of a mechanism or interconnecting network,"[81] EPA posits that it may impose unprecedented beyond-the-unit (and even beyond the source category) measures in establishing the emission guideline for existing EGUs. EPA asserts that a "system of emission reduction" can be "*virtually any 'set of things' that reduce emissions*."[82] EPA then asserts that the "[i]nterconnected nature of the electricity system" means that EPA's "best system of emission reduction" may include not only measures that increase the efficiency of individual affected EGUs, but also measures that "draw[ ] utilization away from higher-emitting fossil fuel-fired EGUs, thereby lowering those EGUs' emissions."[83] This includes measures to "reduc[e] overall electric demand through demand-side energy efficiency measures."[84] But if the "interconnected nature of the electrical system" permits EPA to bring all aspects of that system under the control of section 111(d), including the

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[79] *See Util. Air Regulatory Grp. v. EPA*, 134 S.Ct. 2427, 2449 (2014).
[80] *Id.* at 2444.
[81] 79 Fed. Reg. at 34,885 (citation omitted).
[82] Legal Memorandum at 51 (emphasis added).
[83] Legal Memorandum at 43.
[84] Legal Memorandum at 45.

end-users of electricity,[85] there is no apparent end to EPA's authority to regulate human behavior as a means to reduce $CO_2$ emissions.

EPA's website, for example, is full of tips for families and businesses to reduce their electricity consumption.[86] Each of these suggestions could be made mandatory and used as the basis for a BSER determination. For example:

- Energy Efficiency: "ENERGY STAR is a U.S. Environmental Protection Agency (EPA) voluntary program that helps businesses and individuals ... ' ... to identify and promote energy–efficient products and buildings in order to reduce energy consumption, improve energy security, and reduce pollution through voluntary labeling of or other forms of communication about products and buildings that meet the highest energy efficiency standards.'"[87] ENERGY STAR asserts that it helped Americans "prevent[ ] more than 277 million metric tons of GHG emissions ... in 2013 alone"[88] and "more than 1.9 billion metric tons of greenhouse gas emissions over the past two decades."[89] Under EPA's definition of "system of emission reduction," EPA could adopt emission performance goals that rely on every state's adoption of ENERGY STAR requirements as binding requirements for appliance manufacturers, residential and commercial developers, and consumers.
- Water Conservation: EPA's Climate Change website advises that "Three percent of the nation's energy is used to pump and treat water[,] so conserving water conserves energy that reduces greenhouse gas pollution."[90] EPA's WaterSense website, in turn, advises that installing water-efficient WaterSense products in homes throughout America would save trillions of gallons of water per year. For example, according to EPA, "if every home in the United States installed WaterSense labeled showerheads, we could save ...more than 260 billion gallons of water annually" and "avoid about $2.6 billion in energy costs for heating water."[91] As another example, "[i]f all old, inefficient toilets in the United States were replaced with WaterSense labeled models, we could save 520 billion gallons of water per year ... ."[92] And, according to EPA, "[w]e could save billions of gallons nationwide each year by retrofitting bathroom sink faucets with models that have earned the WaterSense label."[93] Under EPA's definition of "system of emission reduction," then, EPA could adopt emission performance goals that rely on every states' adoption of its WaterSense specifications as binding requirements for manufacturers, developers and consumers.

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[85] *See, e.g.,* 79 Fed. Reg. at 34,871; *see also* Legal Memorandum at 44.
[86] EPA, Climate Change, What You Can Do, http://www.epa.gov/climatechange/wycd/.
[87] ENERGY STAR, About ENERGY STAR, http://www.energystar.gov/about/.
[88] ENERGY STAR, *ENERGY STAR® Overview of 2013 Achievements*, www.energystar.gov/sites/default/uploads/about/old/files/EnergyStar_POY_4page_040414_PrintReady_508compliant.pdf.
[89] ENERGY STAR, About ENERGY STAR, http://www.energystar.gov/about/.
[90] EPA, Climate Change, What You Can Do: At Home, http://www.epa.gov/climatechange/wycd/home.html.
[91] EPA, WaterSense, Products, Showerheads, http://www.epa.gov/watersense/products/showerheads.html.
[92] EPA, WaterSense, Products, Toilets, http://www.epa.gov/watersense/products/toilets.html.
[93] EPA, WaterSense, Products, Bathroom Sink Faucets & Accessories, www.epa.gov/watersense/products/bathroom_sink_faucets.html.

EPA's new-found power would not just allow it to determine the kinds of appliances families and businesses can buy; it would also give EPA the power to restrict consumer choices in the supermarket. The "reduced generation" building block in EPA's alternative BSER approach – replacing "generation from higher-emitting affected sources in specific amounts" with "increased zero- or low-emitting generation [or] eliminat[ing] it by increased demand-side energy efficiency"[94] – is just an electricity-specific example of product substitution. "[E]lectricity and electricity services" are not the only products produced by stationary sources in a regulated New Source Performance Standard (NSPS) category that are "fungible."[95] EPA could, theoretically, adopt emission guidelines for magnetic tape coating facilities[96] that assume states will impose restrictions on the production of tape-based information storage media. Production would simply switch to CDs, DVDs, and thumb drives.[97] And, depending on whether EPA was more concerned with emissions from glass manufacturing plants[98] or the beverage can surface coating industry,[99] EPA could craft emission guidelines that effectively required beverage manufacturers to put more of their products into cans instead of bottles, or vice versa. In the guise of environmental regulation, EPA could assume increasing control over the products, raw materials, and production choices of numerous industries.

Clearly, EPA's proposed interpretation of "system of emission reduction" would bring about an "enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization."[100] An almost limitless interpretation of "system of emission reduction" that would expand EPA's authority to regulate not only all aspects of the national electricity system, but all end-users of electricity and purchasers of multiple consumer goods, must be rejected as unreasonable. EPA's limitless interpretation of BSER is wrong, and its proposal is properly subject to challenge under either traditional or modern, "relocated" nondelegation principles.

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[94] Legal Memorandum at 34.
[95] *Id.* at 44.
[96] *See* 40 C.F.R. Part 60, Subpart SSS.
[97] *See* 76 Fed. Reg. 65,653, 65,658 (Oct. 24, 2011) (noting that "the primary product of this industry has been superseded by ... optical storage media[.]").
[98] *See* 40 C.F.R. Part 60, Subpart CC.
[99] *See* 40 C.F.R. Part 60, Subpart WW.
[100] *See Util. Air Regulatory Grp.*, 134 S.Ct. at 2444.

2. EPA's interpretation of "system of emission reduction" is unreasonable because it is inconsistent with the agency's longstanding, and continuing, interpretation of that phrase as a technology-based system of emissions control.

EPA's proposed interpretation of "system" (in the phrase "best system of emission reduction") is not only contrary to the statute and Congressional intent, as discussed above, it is contrary to EPA's own historical *and current* interpretations of the same word as used in section 111(a)(1). EPA stated repeatedly, when it adopted Subpart B, that it read the legislative history as requiring EPA to take a "technology-based approach" to setting emission limitations.[101] In particular, EPA said that, in determining BSER, Congress intended EPA to use as "criteria for decision-making ... the availability and costs of control technology."[102] In other words, EPA said, "EPA's emission guidelines will reflect best available technology considering cost ... ."[103] Since then, EPA has repeatedly interpreted BSER as a control technology, for both new source and existing source performance standards.

Earlier this year, in the preamble to EPA's proposed NSPS for GHG emissions from new electric utility generating units, EPA commented that it has "frequently referred to [BSER] as the 'best demonstrated technology' (BDT)."[104] EPA was correct. EPA has traditionally explained the process by which it crafts emission guidelines as one in which it first defines the specific kind of apparatus to which the guidelines will apply, identifies the "best demonstrated technology" for that apparatus, and then develops guidelines based on the performance of that "best demonstrated technology." In a 1989 *Federal Register* notice, EPA stated:

> Emission guidelines for existing sources are the product of a series of decisions related to certain key elements for the source category being considered for regulation. The elements in this "decision" are generally the following:
>
> (1) Identification of source category to be regulated – usually an emission source category, but can be a process or group of processes within an industry.
>
> (2) Definition of designated facility – the piece or pieces of equipment that comprise the sources to which the guidelines apply.
>
> (3) Selection of designated pollutant(s) . . .
>
> (4) Identification of "*best demonstrated technology*" – the *technology* on which the guidelines are based ...

[101] 40 Fed. Reg. at 53,342.
[102] *Id.*
[103] *Id.*
[104] 79 Fed. Reg. 1430, 1444 n. 62 (Jan. 8, 2014).

(5) Selection of format for the guidelines – the form in which the guidelines are expressed, i.e., as a percent reduction in emissions, as emission limits, as pollutant concentrations, or as equipment or work practice guidelines.

(6) Development of actual guidelines – generally emission limits based on what "*best demonstrated technology*" can achieve. Only in unusual cases do guidelines require that a specific technology be used. In general, the source owner or operator may select any method for complying with the guidelines.

(7) Other considerations – in addition to emission limits, emission guidelines usually include: guidelines for visible emissions, modification/ reconstruction provisions, monitoring requirements, performance test methods and compliance procedures, and reporting and recordkeeping requirements.[105]

Since then, EPA has routinely repeated its understanding that a "system of emission reduction" (for purposes of determining BSER) is a technology:

- 2005: "As with any NSPS analysis, EPA evaluated the controls that effect the best emission reduction of the pollutant in question"[106]
- 2008: "[S]tandards of performance promulgated under section 111 are based on 'the best system of emission reductions' which generally equates to some type of control technology."[107]
- 2012: "NSPS are based on the effectiveness of one or more specific technological systems of emissions control, unless certain conditions are met."[108]

As recently as September 2013, EPA was describing BSER as emissions reduction technology:

> Section 111(a)(1) provides that NSPS are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of *control* is commonly referred to as *best demonstrated technology (BDT)*. In determining BDT, EPA typically conducts a technology review that identifies what *emission reduction systems* exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation. The resultant standard is commonly a numerical emissions limit, expressed as a performance level (i.e. a rate-based standard). ... Section 111(d)

[105] 54 Fed. Reg. 52,209, 52,211 (Dec. 20, 1989) (emphasis added).
[106] 70 Fed. Reg. 62,213, 62,216 (Oct. 28, 2005).
[107] 73 Fed. Reg. 72,962, 72,970 (Dec. 1, 2008).
[108] 77 Fed. Reg. 48,433, 48,439 (Aug. 14, 2012).

guidelines, like NSPS standards, must reflect the emission reduction achievable through the application of BDT.[109]

Even this year, outside this rulemaking, EPA has continued to construe BSER in the traditional fashion. For example, In July 2014, EPA proposed revisions to its NSPS for grain elevators.[110] EPA acknowledged that BSER "has been referred to in the past as 'best demonstrated technology' or BDT."[111] To conduct its BSER analysis, EPA "identified currently used, new and emerging control systems and assessed whether they represent advances in emission reduction techniques compared to the control techniques used to comply with the existing NSPS."[112] In particular, EPA looked at "control techniques" such as "application of mineral oil as a dust suppression technique," but identified "[n]o other [new] emission control technologies or work practices."[113] EPA did not mandate that elevator operators limit the storage of wheat in favor of storing more corn, because it produces less fugitive dust. And, in its rulemaking to establish NSPS for GHG emissions from EGUs, EPA commented that BSER is "generally, but not required to be always, a technological control."[114] EPA quoted the legislative history for the 1977 CAA Amendments, which described Congress's adoption of the BSER requirement in 1970 as "the first time [Congress] imposed a requirement for specified levels of control technology."[115] EPA took the position that the definition of "standard of performance" "makes clear that the standard of performance must be based on *controls* that constitute 'the best system of emission reduction ... adequately demonstrated' (BSER)."[116] And, ultimately, after "consider[ing] three alternative control technology configurations as potentially representing the BSER," EPA proposed that "efficient generating technology implementing partial [carbon capture and storage] is the BSER adequately demonstrated for [new fossil fuel-fired boiler and IGCC EGUs]."[117]

The only place EPA has proposed to interpret "system of emission reduction" so broadly as to mean "virtually any 'set of things' that reduce[s] emissions" is in EPA's proposed CPP. In

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[109] EPA, Background on Establishing New Source Performance Standards (NSPS) Under the CAA (*available at* www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf) (emphasis added).
[110] *See* 79 Fed. Reg. 39,242 (July 9, 2014).
[111] 79 Fed. Reg. at 39,245.
[112] 79 Fed. Reg. at 39,248.
[113] 79 Fed. Reg. at 39,249.
[114] 79 Fed. Reg. at 1463.
[115] 79 Fed. Reg. at 1465, *quoting* S. Rep. 95-127 at 17 (1977).
[116] 79 Fed. Reg. at 1443 (emphasis added).
[117] 79 Fed. Reg. at 1467-1468.

Subpart B, in 44 years of *Federal Register* notices, and even in other rulemaking notices published this year for new sources emitting the same pollutant, EPA has continued to interpret "system of emission reduction" to mean something akin to emission control equipment and process changes. Because EPA's proposed CPP contradicts its historical and on-going interpretation of "best system of emission reduction," it is unreasonable and unlawful.

3. EPA's chosen BSER is not "adequately demonstrated" as a whole.

The standards of performance that states include in their § 111(d) implementation plans must, under § 111(a)(1) of the Clean Air Act, reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[118] "An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[119]

Here, EPA proposes a "best system of emission reduction" that comprises (1) heat rate improvements, (2) re-dispatch to existing NGCC units, (3) increased use of renewable energy, and (4) increased use of demand-side energy efficiency. EPA asserts that the "combination of all four building blocks" is "adequately demonstrated" because, EPA says, it is "technically feasible; it is capable of achieving meaningful reductions in $CO_2$ emissions from affected EGUs at a reasonable cost; it satisfies the other BSER criteria as well; and its components are well-established."[120] In the Legal Memorandum, EPA asserts that "the measures in each of the building blocks are 'adequately demonstrated' because they are each well-established in numerous states, many of them have already been relied on to reduce air pollutants, including $CO_2$, from fossil fuel-fired EGUs and, as noted, they may be undertaken by the affected EGUs or, in general, required by the states."[121] In essence, EPA asserts that each building block is "adequately demonstrated" because those measures, individually, "already have been

[118] 42 U.S.C. § 7411(a)(1).
[119] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-434 (D.C. Cir. 1973).
[120] 79 Fed. Reg. at 34,885.
[121] Legal Memorandum at 15.

implemented in many states..."[122] With regard to the alternative approach to BSER, EPA asserts that reduced utilization is "adequately demonstrated" because affected EGUs can "adjust their own generation," states can "impose requirements," and "other entities that operate in the various types of markets in the states can be expected to respond to the reduction in generation from the fossil-fuel fired EGUs by undertaking the measures in the building blocks or other actions that would assure reliability."[123] But this, to some extent, begs the question. EPA does not point to any state that is currently utilizing *every* building block, combined, in the manner and at the levels proposed in the Clean Power Plan. EPA does not point to any state that has imposed operating restrictions on affected EGUs at the levels that would have to be imposed to meet EPA's proposed carbon intensity goals. EPA asserts that each building block, by itself, has worked in some state at some point, and thus assumes that they will work in combination. But an assumption is not a demonstration. EPA has not shown that either variation of its building block BSER is "adequately demonstrated."

4. EPA's broad interpretation of "system of emission reduction" would lead to absurd results.

As EPA has acknowledged in the past, "the literal meaning of statutory requirements should not be considered to indicate congressional intent if that literal meaning would produce a result that is senseless or that is otherwise inconsistent with – and especially one that undermines – underlying congressional purpose."[124] In other words, when interpreting statutes, "absurd results are to be avoided."[125] Yet, the boundless interpretation of "system of emission reduction" that EPA has proposed -- "a set of things working together as parts of a mechanism or interconnecting network"[126] opens the floodgates to absurd results.

On the one hand, EPA's proposed definition is too narrow. Burning low-sulfur coal, for example, is not alone a "set of things working together," but would clearly qualify as a "system of emission reduction" under section 301(m) and the 1990 amendments to the CAA. Indeed, the first building block of EPA's proposed BSER – heat rate improvements – would not, by itself, meet EPA's proposed definition of a "system of emission reduction." Nor would increased

[122] *Id.* at 67.
[123] *Id.* at 16.
[124] *See* 75 Fed. Reg. 31,514, 31,517 (June 3, 2010).
[125] *United States* v. *Wilson*, 503 U. S. 329, 334 (1992).
[126] EPA Legal Memorandum at 36-37, n. 31 (citing *Oxford Dictionary of English* (3rd ed. 2010)).

generation from NGCC units alone qualify as a "system of emission reduction." EPA asserts that "reduced generation is a 'set of things' – which include reduced use of generating equipment and therefore reduced fuel input – that the affected source may take to reduce its $CO_2$ emissions,"[127] but this increased utilization of a different source may not be within the control of the source whose emissions are to be reduced. This mangled reasoning ("a 'set of things' ... that the affected source may take") ignores the reality of the electricity generating system and stretches the meaning of "set of things" beyond any reasonable interpretation. "Reduced generation" is not a "thing," it is the product of a comparison between two operating states. It is, in fact, the *absence* of a thing – a quantity of generation. Even in EPA's model, this reduced generation must be offset by increased generation from other types of generators, most of which are not under common control. Thus, EPA's proposed definition excludes pollution control measures that are inarguably "systems of emission reduction" and would also exclude at least some of the new "systems of emission reduction" on which EPA's current BSER proposal relies.

EPA's proposed definition is also too broad. EPA interprets its new definition of "system of emission reduction" to "encompass[ ] virtually any 'set of things' that reduce emissions."[128] These "things," moreover, do not all take place at the existing sources in the source category being regulated. Two of the four "building blocks" in EPA's main BSER approach rely on using alternative sources of electricity (NGCC units or low- or zero-carbon generation).[129] The fourth building block is simply encouraging people to use less electricity.[130] Under EPA's interpretation of "system of emission reduction," EPA could have adopted a BSER that comprised only the last three building blocks. In other words, EPA could have selected a "best system for emission reduction" for affected EGUs that imposed no direct obligations on the category of existing sources that EPA is purportedly regulating. Indeed, under EPA's "portfolio approach," states could develop plans that only "impos[e] requirements on other entities," not including EGUs, "as long as, again, the required emission performance level is met."[131] In short, EPA has taken a statute that requires states to adopt plans that "establish[ ] standards of

[127] Legal Memorandum at 82.
[128] Legal Memorandum at 51.
[129] 79 Fed. Reg. at 34,858.
[130] 79 Fed. Reg. at 34,858.
[131] 79 Fed. Reg. at 34,853.

performance for any existing source,"[132] and interpreted it in a way that would allow states to adopt plans that impose *no* obligations on *any* existing source in the relevant source category.[133]

Moreover, if EPA's new interpretations allow the agency to base BSER on any measures that "displace, or avoid the need for, generation from the affected EGUs,"[134] there is no end to the restrictions on human and commercial activities that EPA could contemplate as BSER. As discussed above, under EPA's definition of "system of emission reduction," EPA could adopt emission performance goals that rely on every state's adoption of ENERGY STAR and WaterSense requirements as binding requirements for appliance manufacturers, developers, and consumers. But, EPA would not need to stop at regulating the kinds of homes and businesses people build, and the kinds of appliances their families and customers use.[135]

EPA's proposed interpretation of "system of emission reduction" and the new "portfolio approach" to setting inviolate state goals that EPA has proposed to adopt in its CPP, contains no limiting principle that constrains the agency's regulatory reach. Never before has EPA claimed the authority to limit productive capacity or control the rate of customer usage of a particular product, and the assertion of authority to do so here has no foundation in the CAA. Because EPA's interpretation would purport to give EPA broad power to regulate human behavior, EPA's interpretation of "system of emission reduction" must be rejected.

### C. The Proposed Guidelines Violate the Requirements of EPA's Own Implementing Regulations

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") recently confirmed the common-sense concept that federal agencies are bound by their own regulations. In *National Environmental Development Association's Clean Air Project v. EPA*, the court held:

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[132] 42 U.S.C. § 7411(d)(1).

[133] *See* Legal Memorandum at 94 ("The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance – and, for the portfolio approach, in imposing requirements on other entities – as long as, again, the required emission performance level is met.").

[134] Legal Memorandum at 96.

[135] The Center for Biological Diversity suggests that reducing population growth may be necessary to reduce greenhouse gas emissions, stating, "A 2009 study of the relationship between population growth and global warming determined that the 'carbon legacy' of just one child can produce 20 times more greenhouse gas than a person will save by driving a high-mileage car, recycling, using energy-efficient appliances and light bulbs, etc. Each child born in the United States will add about 9,441 metric tons of carbon dioxide to the carbon legacy of an average parent." The study concludes, "Clearly, the potential savings from reduced reproduction are huge compared to the savings that can be achieved by changes in lifestyle." Center for Biological Diversity, *Human Population Growth and Climate Change*, http://www.biologicaldiversity.org/programs/population_and_sustainability/climate/.

> It is "axiomatic[ ]" ... "that an agency is bound by its own regulations." *Panhandle Eastern Pipe Line Co. v. FERC*, 613 F.2d 1120, 1135 (D.C. Cir. 1979) (holding that an agency does not have authority to "play fast and loose with its own regulations"). "Although it is within the power of [an] agency to amend or repeal its own regulations, [an] agency is not free to ignore or violate its regulations while they remain in effect." *U.S. Lines, Inc. v. Fed. Mar. Comm'n*, 584 F.2d 519, 526 n.20 (D.C. Cir. 1978). Thus, an agency action may be set aside as arbitrary and capricious if the agency fails to "comply with its own regulations." *Environmental, LLC v. FCC*, 661 F.3d 80, 85 (D.C. Cir. 2011).[136]

Thus, to the extent that the CPP violates EPA's own regulations, it is unlawful.

EPA asserts that it developed its proposed emission guidelines "in accordance with sections 111(d) of the CAA and subpart B of this part."[137] Indeed, the proposed regulations explicitly require states to "follow the requirements of subpart B of this part (Adoption and Submittal of state plans for Designated Facilities) and demonstrate that they were met in [the] state plan."[138] The proposed regulations do state that, "[t]o the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply."[139] EPA's Legal Memorandum makes clear, however, that "the present rulemaking ... follow[s] the requirements of the implementing regulations, except that the EPA is extending certain timetables, as described in the preamble."[140] Thus, EPA acknowledges that its Clean Power Plan must comply with 40 C.F.R. Part 60, Subpart B (with the extended timetables). Nonetheless, several provisions of the CPP contradict the literal requirements of Subpart B, which, as explained below, are unlawful and must be removed from EPA's proposal.

### D. EPA's proposal reflects what EPA believes to be the best system of emission reduction for *states*, in violation of Subpart B's requirement to promulgate a guideline document that "reflects the best system of emission reduction ... for *designated facilities*."

EPA's rules for adoption and submittal of state plans for designated facilities are set forth in 40 C.F.R. Part 60, Subpart B. Subpart B instructs EPA that, "[c]oncurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information

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[136] *Nat'l Envtl. Dev. Ass'ns Clean Air Project v. EPA*, 752 F.3d 999 (D.C. Cir. 2014).
[137] Proposed 40 C.F.R. § 60.5700. *See also* 79 Fed. Reg. at 34,852 ("This proposed action is consistent with the requirements of CAA section 111(d) and the implementing regulations.").
[138] Proposed 40 C.F.R. § 60.5740(b).
[139] Proposed 40 C.F.R. § 60.5700.
[140] Legal Memorandum at 9; *see also* 79 Fed. Reg. at 34,853.

pertinent to control of the designated pollutant f[ro]m designated facilities."[141] EPA has stated that its *Federal Register* notice, along with its supporting documents, constitute its draft guideline document.[142]

Subpart B lists the information that a guideline document must include. That information includes, among other things, "[i]nformation on the degree of emission reduction which is achievable with each system [of emission reduction that has been adequately demonstrated], together with information on the costs and environmental effects of applying each system *to designated facilities*."[143] The guideline document also must include "[a]n emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved."[144] EPA's regulations define "emission guideline" to mean:

> a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated *for designated facilities*.[145]

Both of these provisions, then, instruct EPA to develop emission guidelines that are based on "the best system of emission reduction" that "has been adequately demonstrated *for designated facilities*."

"Designated facilities" is also a defined term. Subpart B defines "designated facility" to mean "any existing facility ... which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility ...."[146] "Existing facility" and "affected facility" are also defined terms. "Existing facility" means "any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type."[147] "Affected facility," in

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[141] 40 C.F.R. § 60.22(a).
[142] Legal Memorandum at 32.
[143] 40 C.F.R. § 60.22(b)(3) (emphasis added).
[144] 40 C.F.R. § 60.22(b)(5).
[145] 40 C.F.R. § 60.21(e) (emphasis added).
[146] 40 C.F.R. § 60.21(b).
[147] 40 C.F.R. §60.2.

turn, means "any apparatus to which a standard is applicable."[148] Finally, "standard" is defined to mean "a standard of performance proposed or promulgated under [Part 60]."[149] Thus, a "designated facility" is an existing stationary source that is the same type of source for which EPA has proposed or promulgated a New Source Performance Standard and emits the pollutant that is the subject of the emission guidelines.[150]

Here, the "designated facilities" are the "affected EGUs."[151] Yet, EPA's emission guidelines do not reflect the best system of emission reduction that has been adequately demonstrated *for those affected EGUs*, as required by Subpart B. Instead, it reflects the degree of emission reduction that EPA believes is achievable through the application of the best system of emission reduction that EPA has determined has been adequately demonstrated for *states.* EPA's Legal Memorandum makes this quite clear: "In this rulemaking, the EPA proposes to determine the 'best system of emission reduction ... adequately demonstrated' *on a state-by-state basis*."[152] EPA further explains that its emission guidelines are then based on this state-by-state determination of BSER:

> This proposed rulemaking – including the preamble and the supporting documents -- comprise the "draft guideline document." The documents contain the "information for the development of State plans" described in the regulations. This information includes descriptions as well as technical and economic evaluations of the four building blocks. This information also includes the EPA's application of the BSER *to each state*, and the EPA's calculation of the resulting proposed *state goals*. *These state goals comprise the proposed "emission guidelines.*[153]

The Legal Memorandum confirms that this "statewide" determination of the BSER is fundamental to EPA's approach.[154]

The preamble, too, makes clear that EPA determined BSER by reference to what it believed had been adequately demonstrated by *the states*. The preamble explains that "the EPA

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[148] *Id.*
[149] *Id.*
[150] *See* 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).
[151] *See* Proposed 40 C.F.R. §§ 60.5700, 60.5795.
[152] Legal Memorandum at 42 (emphasis added).
[153] Legal Memorandum at 32-33 (emphasis added). *See also* 79 Fed. Reg. at 34,851 (stating: "Based on the EPA's application of the BSER *to each state*, the EPA is proposing to establish, as part of the emission guidelines, state-specific goals, expressed as average emission rates for fossil fuel-fired EGUs. Each state's goals comprise the EPA's determination of the emission limitation achievable through application of the BSER in that state.") (emphasis added).
[154] Legal Memorandum at 18 ("It should be noted that an important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis.").

is proposing state-specific goals that reflect the EPA's calculation of the emission limitation that *each state* can achieve through the application of the BSER."[155] It further explains:

> To set the state-specific $CO_2$ goals, the EPA analyzed the practical and affordable strategies that *states* and utilities are already using to lower carbon pollution from the power sector. These strategies include improvements in efficiency at carbon-intensive power plants, programs that enhance the dispatch priority of, and spur private investments in, low emitting and renewable power sources, as well as programs that help homes and businesses use electricity more efficiently. In addition, in calculating each state's $CO_2$ goal, the EPA took into consideration the state's fuel mix, its electricity market and numerous other factors. Thus, each state's goal reflects its unique conditions.[156]

Thus, EPA's proposed CPP overlooks the fundamental regulatory requirement that its guideline documents must provide information on systems of emission reduction that can be applied *to affected EGUs*,[157] and emission guidelines that are based on the best system of emission reduction that has been adequately demonstrated *for affected EGUs*.[158] Instead, EPA's proposed guideline document discusses and selects what it believes to be the best system of emission reduction that has been adequately demonstrated for the *states* in which those affected EGUs are found, which is contrary to 40 C.F.R. Part 60, Subpart B, and therefore unlawful.

### E. EPA's broad interpretation of "system of emission reduction" conflicts with its more limited interpretation of "system" in Subparts A and B.

As discussed above, EPA has proposed to interpret the word "system" in "system of emission reduction" to mean "a set of things working together as parts of a mechanism or interconnecting network; a complex whole."[159] Based on this nebulous definition, EPA has proposed that "virtually any 'set of things' that reduce[s] emissions" is a "system of emission reduction."[160] As discussed above, this broad interpretation of "system of emission reduction" conflicts with the narrower interpretation reflected in the legislative history and for related terms in the CAA. EPA's broad interpretation also conflicts with the narrower interpretation of "system of emission reduction" reflected in Subparts A and B.

[155] 79 Fed. Reg. at 34,834.
[156] 79 Fed. Reg. at 34,833(emphasis added).
[157] *See* 40 C.F.R. § 60.22(b)(3).
[158] *See* 40 C.F.R. § 60.22(b)(5).
[159] Legal Memorandum at 51.
[160] *Id.*

This narrower interpretation is best reflected in Subpart B's discussion of state plans' compliance schedules. Under EPA's implementing regulations, "[e]ach plan shall include emission standards and compliance schedules." "Compliance schedule" is defined as "a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance."[161] The regulations further state that "[a]ny compliance schedule extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities."[162] "Increments of progress," in turn, is defined to mean "steps to achieve compliance which must be taken by an owner or operator of a designated facility."[163] The regulations go on to describe the minimum increments of progress that must be included, all of which focus on activities to be accomplished at the designated facility:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for *emission control systems or for process modifications,* or issuance of orders for the purchase of component parts to accomplish *emission control or process modification*;

(3) Initiation of on-site construction or installation of *emission control equipment or process change*;

(4) Completion of on-site construction or installation of *emission control equipment or process change*; and

(5) Final compliance.[164]

These standard increments of progress merely reinforce what is obvious from a review of the statute – "system of emission reduction" is properly understood to mean, and except for the CPP proposal has been understood by EPA to mean, something akin to emission control equipment or process modifications.

The states need not include these specific "increments of progress" if it is not "practicable," or if a specific subpart specifies otherwise.[165] This does not indicate, however, that EPA understands "systems of emission reduction" to mean something significantly different

[161] 40 C.F.R. § 60.21(g).
[162] 40 C.F.R. § 60.24(e)(1).
[163] 40 C.F.R. § 60.21(h).
[164] *Id.* (emphasis added).
[165] 40 C.F.R. § 60.24(e)(1).

from emission control systems or process modifications. EPA promulgated the regulatory language discussed above, including the definition of "increments of progress" and the exception for when such increments are not "practicable," in 1975 – two years *before* Congress inserted the word "technological" into the phrase "best system of emission reduction"[166] – and the language in the implementing regulation has not changed since.[167] And as explained above, in 1975, EPA understood "system of emission control" to mean "control technology."[168]

This understanding of "system of emission reduction" to mean a piece of emission control equipment, or an emission control system, is also reflected in the Subpart A rules for new sources. Subpart A states that an existing facility that undertakes a "physical or operational change … which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification," rendering the facility an "affected facility" for purposes of Subpart A.[169] The rules go on to list several actions that will not be considered modifications, including "[t]he addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial."[170] The rule thus clarifies that the installation of a system of emission reduction, to comply with a state plan under Subpart B or another Clean Air Act program, will not turn an existing source into a modified source. But more importantly, for purposes of the Clean Power Plan, it demonstrates yet again that "system of emission reduction" is properly understood to mean, and has otherwise been understood by EPA to mean, something akin to emission control equipment or process modifications.

Because EPA's proposed interpretation of BSER is contrary to Subpart B's interpretation of a "system of emission reduction" as "emission control equipment or [a] process change," and Subpart A's interpretation of a "system of emission reduction" as an "emission control system" or "device," it is unreasonable and unlawful.

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[166] *See, e.g.,* 79 Fed. Reg. 1430, 1462-1463 at n. 131 (Jan. 8, 2014).
[167] *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975).
[168] 40 Fed. Reg. at 53,341.
[169] 40 C.F.R. § 60.14(a).
[170] 40 C.F.R § 60.14(e)(5).

### F. EPA's emission guidelines permit states to apply emission standards to both "designated facilities" and other entities, but Subpart B permits the application of emissions standards only to "designated facilities."

Under section 111(d)(1), states are required to submit plans that establish "standards of performance for" existing sources.[171] "Standard of performance" is defined to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction..."[172] Under this definition, originally, "standards of performance could be established only in the form of emissions limitations, based on output, and not in the form of work practice or operation requirements."[173] Congress then amended section 111 in 1977 to add subsection (h), which allows EPA to "promulgate a design, equipment, work practice, or operational standard, or combination thereof," if EPA concludes "it is not feasible to prescribe or enforce a standard of performance..."[174]

The statutory definition of "standard of performance," and the alternatives to standards of performance that section 111(h) authorizes in limited circumstances, are reflected in the implementing regulations' definition of "emission standard." Under Subpart B, states' section 111(d) plans must "establish[ ] emission standards for designated pollutants from designated facilities ... ."[175] Under the rules, an "emission standard" generally may be written as "*an allowable rate of emissions into the atmosphere*, ... an allowance system, or ... *equipment specifications* for control of air pollution emissions."[176] However, the rules require the emission standards to be "based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable."[177] Thus, like the Clean Air Act, EPA's Subpart B rules generally require emission standards to be written as emission limitations (or allowance systems), unless they cannot be written in that manner, in which case they may be written as equipment specifications (or, under the Act, design, work practice, or operational standards).

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[171] 42 U.S.C. § 7411(d)(1).
[172] 42 U.S.C. § 7411(a)(1).
[173] *PPG Industries, Inc. v. Harrison*, 660 F.2d 628, 636 (5th Cir. 1981) (citation omitted).
[174] 42 U.S.C. § 7411(h)(1). *See PPG Industries*, 660 F.2d at 636.
[175] 40 C.F.R. § 60.21(c).
[176] 40 C.F.R. § 60.21(f) (emphasis added). AEP will not address, in these comments, whether the inclusion of allowance systems in the regulatory definition of "emission standard" is statutorily permissible, as that issue was not raised by EPA's proposal.
[177] 40 C.F.R. § 60.24(b)(1).

EPA's proposed CPP, however, would provide a new, expanded definition of "emission standard," limited only to Subpart UUUU, which would incorporate the Subpart B definition of "emission standard," but also add "any requirement applicable *to any affected entity other than an affected source* that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources ...."[178] The Plan defines "Affected Entity" to mean "[a]n affected EGU, *or another entity with obligations under this subpart* for the purpose of meeting the emissions performance goal requirements in these emission guidelines."[179] Thus, the proposed CPP presumes that states will adopt plans that impose obligations on sources other than affected EGUs, and would expand the definition of "emission standard" to make that possible. The preamble explains:

> The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance – and, for the portfolio approach, in imposing requirements on other entities – as long as, again, the required emission performance level is met.[180]

EPA lacks the statutory authority to expand the regulatory definition of "emission standard" in that manner. A requirement to reduce utilization is not a "standard of performance," whether it is effectuated indirectly through building blocks 2, 3, and 4 (in EPA's primary BSER proposal) or by directly requiring reduced utilization of affected EGUs (under EPA's alternative BSER proposal). And, there is nothing in Subpart B that permits the states to adopt a plan that imposes obligations on any category of sources or entities other than affected EGUs in the source category. EPA has said that it "is following the requirements of the implementing regulations" in its CPP.[181] Although EPA's proposed CPP would amend the definition of "emission standard," it does not amend the definition of "plan," the requirements of §60.24(b)(3), or any other portion of Subpart B. And numerous provisions of the implementing regulations make clear that emission standards may apply only to "designated facilities."

First, following EPA's promulgation of a final guideline document, Subpart B requires each state to "adopt and submit ... a plan for the control of the designated pollutant to which the guideline document applies."[182] "Plan" is a defined term meaning "a plan under section 111(d)

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[178] Proposed 40 C.F.R. § 60.5820 (emphasis added).
[179] *Id.* (emphasis added).
[180] 79 Fed. Reg. at 34,853.
[181] Legal Memorandum at 9.
[182] 40 C.F.R. § 60.23(a)(1).

of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards."[183] Subpart B further states that "[e]mission standards shall apply to all designated facilities within the State."[184] Combined, these provisions make clear that "emission standards" are to be applied to "designated facilities."

Next, state plans must contain provisions for "[p]eriodic inspection and, when applicable, testing of *designated facilities*."[185] If a plan has a "compliance schedule extending more than 12 months from the date required for submittal of the plan," that plan "must include legally enforceable increments of progress to achieve compliance for each *designated facility* or category of facilities."[186] States, then, may take into account individual facilities' characteristics when determining the emissions standards and compliance schedules that will apply to each facility. EPA's regulations authorize states to give particular facilities, or classes of facilities, "less stringent emissions standards or longer compliance schedules" if the state can demonstrate:

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors *specific to the facility* (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.[187]

And, under certain circumstances, "the owner or operator of a *designated facility to which regulations proposed and promulgated under this section will apply*" may apply to EPA for "less stringent emission standards or longer compliance schedules than those otherwise required."[188] These provisions, again, demonstrate that Subpart B expects the states to take a "source-based" approach in preparing their plans. Consequently, EPA's proposal to allow states to impose legal obligations on sources or entities other than affected EGUs violates 40 C.F.R. Part 60, Subpart B, and is unreasonable and unlawful.

It should be noted that EPA's alternative proposal, under which state plans would "impose legal responsibility on the affected EGUs to achieve the full level of ... emission performance" required under the CPP, "but also include enforceable or complementary RE and

[183] 40 C.F.R. § 60.21(c).
[184] 40 C.F.R. § 60.24(b)(3).
[185] 40 C.F.R. § 60.25(b)(1) (emphasis added).
[186] 40 C.F.R. § 60.24(e)(1) (emphasis added).
[187] 40 C.F.R. § 60.24(f) (emphasis added).
[188] 40 C.F.R. § 60.27(e)(2) (emphasis added).

demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions"[189] would also be unlawful. Under any such plan, affected EGUs would not control their own compliance. A plan that imposed legal responsibility only on affected EGUs, but made compliance with standards of performance possible only through redispatch to less carbon-intensive affected EGUs, substitution with low- and zero-carbon generation, and the adoption or expansion of demand-side energy efficiency programs would, in effect, impose vicarious liability on the owners and operators of affected EGUs for the acts or omissions of third parties. Affected EGUs would have to rely on RTOs to change their dispatch models;[190] NGCC owners and operators to operate and maintain their units;[191] other independent power producers to build wind and solar farms;[192] and electric utilities' residential, commercial, and industrial customers to better insulate their homes, install energy-efficient lighting, and otherwise reduce their power consumption.[193]

The imposition of vicarious liability violates substantive due process if the party exposed to the vicarious liability does not have control over the party, or is not in a business relationship with the party, that is primarily responsible.[194] Thus, EPA's alternative proposal to allow states to impose 100% of the legal responsibility for meeting the state carbon-intensity goals on affected EGUs, while leaving the practical ability to meet those goals in the hands of hundreds of thousands of unaffiliated utility customers and governmental agencies, would not withstand constitutional scrutiny. EPA cannot promulgate state goals that can only be met through the efforts of affected entities other than affected EGUs, and yet impose the obligation to meet those goals entirely on the affected EGUs, if the affected EGUs' owners and operators do not control these other entities or are not in a business relationship with them that would allow them to re-

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[189] 79 Fed. Reg. at 34,902.

[190] *See* 79 Fed. Reg. at 34,888 ("On the regional level, ISO/RTOs control dispatch").

[191] EPA suggests that affected EGUs could take control of their own ability to comply by "invest[ing] in NGCC capacity." Legal Memorandum at 74. However, EPA's analysis assumes that "the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking." 79 Fed. Reg. at 34,882.

[192] EPA suggests, too, that affected EGUs could "invest in renewable capacity." Legal Memorandum at 74. Yet, the owners and operators of one affected EGU would not likely control every renewable energy source in its state.

[193] *See*, *e.g.*, 79 Fed. Reg. at 34,884 ("Owners of affected EGUs as well as other parties can contract for demand-side energy efficiency.").

[194] *Compare Portland Pipe Line Corp. v. Environmental Improvement Comm'n*, 307 A.2d 1, 19 (Me. 1973) (holding, "there is no constitutional bar to the imposition of vicarious liability upon one engaged in business, for the acts of a business associate, when both are engaged in a mutually beneficial relationship and there is, in the relationship, adequate opportunity to locate, among the business associates, the primary liability."),

allocate the costs of non-compliance to the entities primarily responsible for the failure to achieve state performance standards.

## V. The Emission Reductions Required by Building Block 1 Are Not Achievable

From the opening sentence of EPA's evaluation of potential heat rate improvement opportunities, the agency mischaracterizes observed differences in operating efficiencies as being "evidence" that existing coal-based generating units are not being adequately operated or maintained.[195] EPA is incorrect in this conclusion. Heat rate performance is influenced by a variety of known and unknown, controllable and uncontrollable factors, whose interaction and degree of impact is unit-specific and will vary throughout the life of the unit. EPA itself in a 2010 report on available and emerging technologies for reducing greenhouse gas emissions from coal-fired electric generating units stated that:

> The actual overall efficiency that a given coal-fired EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees… Because of these factors, coal-fired EGUs that are identical in design but operated by different utility companies in different locations may have different efficiencies. Thus, the level of effectiveness of a given GHG control technology used to improve the efficiency at one coal-fired EGU facility may not necessarily directly transfer to a coal-fired EGU facility at a different location.[196]

Although EPA in the proposed rule alludes to this wide scope of influences and the "site specific" factors that drive heat rate performance, the agency fails to objectively and holistically account for these drivers, and concludes that, except for the variability attributable to ambient temperatures and load factor, poor operational practices and lack of equipment maintenance or upgrades are the exclusive source of observed "difference[s] in operating efficiency."[197] In fact, EPA's evaluation ignores or does not fully consider the following:

- the other uncontrollable factors that impact heat rate performance;
- the availability, technical viability, and economic feasibility of potential improvement opportunities at individual units;
- heat rate improvement measures that have already been implemented;
- unit-specific factors that influence the magnitude and sustainability of potential heat rate improvements; and
- the impact of other environmental requirements that may mask or eliminate potential heat rate improvements.

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[195] "GHG Abatement Measures TSD". U.S. EPA. June 10, 2014. p. 2-1

[196] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA Office of Air & Radiation, October 2010. p 22-23. (emphasis added)

[197] "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-1.

Had EPA fully considered these factors, the agency would have correctly concluded that both the proposed 6% and alternative 4% targets for heat rate improvements are overly aggressive, and cannot feasibly be implemented by the majority of existing coal-based generating units. Instead of collecting the information necessary to reasonably evaluate these issues, EPA chose to evaluate potential heat rate improvement opportunities by:

- performing a flawed statistical analysis of heat rate variability;
- performing a narrow review of available information on heat rate performance by examining a single technical report with a study of just two units and select vendor information;[198]
- incorrectly estimating the applicability of and cumulative impact of a portfolio of potential improvement measures; and
- incorrectly assuming that a high rate of cumulative improvements are achievable by all coal units.

Based on this evaluation, EPA determined that a 6% efficiency improvement has been adequately demonstrated to be achievable through improved operating practices (4%) and equipment maintenance/upgrades (2%). EPA's flawed assessment is grounded in uninformed and inaccurate assumptions and conclusions that reflect an incomplete understanding of the nature, cost, and availability of potential heat rate improvement opportunities. The sections below provide detailed comments on these fundamental flaws and offer greater context on the factors that drive heat rate performance and the limited opportunities for improvement.

### A. EPA should objectively and holistically consider the full range of issues that influence heat rate performance

Although EPA identifies various factors that influence heat rate, the agency fails to fully or accurately consider these factors when evaluating potential improvement opportunities. This inconsistency results in a BSER determination that is made within a vacuum of what may *potentially* be achievable with operational best practices and equipment upgrades, but which completely ignores competing variables that may diminish or in some cases prohibit measurable improvement. For example, EPA correctly notes that:

> A variety of factors must be considered when comparing the effectiveness of heat rate improvement technologies to increase the efficiency of a given coal-fired EGU. The

[198] Sargent & Lundy's 2009 report "Coal-Fired Power Plant Heat Rate Reductions" provided two examples of heat rate reductions. These two examples are NOT an appropriate basis for an across the board prediction of improvement.

> actual overall efficiency that a given coal-fired EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees. Examples of the factors affecting EGU efficiency at a given facility include:
>
> - thermodynamic cycle
> - coal rank and quality
> - [unit] size
> - pollution control systems
> - operating and maintenance practices
> - cooling system
> - geographic location and ambient conditions
> - load generation flexibility requirements
> - [balance] of plant components.[199]

EPA further states:

> All of the improvement technologies...[identified]... cannot necessarily be implemented at every existing coal-fired EGU facility in the U.S. electric utility fleet. The existing EGU design configuration and other site-specific factors may prevent the technical feasibility of using a given technology.[200]

Despite acknowledging the number of design and operational variables, as well as site-specific factors that affect heat rate performance, EPA fails to adequately consider and apply this knowledge in its evaluation of potential improvement opportunities and in its BSER determination. The following sections examine the fundamental concepts that EPA should objectively consider and apply in developing a final rule. An expanded discussion of these fundamental issues is provided in Appendix A, which contains a white paper developed by AEP on heat rate issues and potential improvement opportunities at coal-based generating plants.

1. Heat rate improvement opportunities are unique to each unit

In examining potential heat rate improvement opportunities at existing units, there are several principles that are critical in determining the realistic applicability and degree of potential heat rate improvement that any specific project might afford, including the following:

- improvements are not uniform and what may work for one unit, may not work for another;

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199 "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-4 – 2.5. (emphasis added)

200 "GHG Abatement Measures TSD". U.S.EPA. June 2014. p.2-5 – 2.6. (emphasis added)

- the heat rate benefit of multiple improvement projects is not necessarily cumulative; improvements in one area can be masked by operations or conditions in another, thus diminishing any overall heat rate improvement;
- outside influences beyond the control of the unit operators can alter or erase heat rate improvements, because plants are dispatched based upon electricity demand, and the availability of other units;
- improvements must be cost-effective and measurable to justify their implementation;
- space constraints may exist on a particular unit that prohibit the addition of equipment or re-routing of ductwork/piping to implement a heat rate improvement project;
- the benefit derived from many of the suggested heat rate improvement technologies is temporary and will diminish over time due to the age and operation of the unit;
- for some heat rate improvement projects the potential benefits will only be apparent at full load operations, and offer no measurable improvements for cyclic or minimum load operations;
- conversely, some base load units would show no benefit to heat rate if the improvement is experienced only at lower loads or during cycling operations;
- EPA's 111(d) proposal suggests that existing coal power plants will be dispatched and operated much differently from the past, so historic experience may not provide an accurate projection of future benefits.

Heat rate improvement projects are valuable and have been frequently implemented because of the benefits of more efficient fuel use, lowered operating costs and improved equipment performance. Most power plant owners regularly assess the potential for heat rate improvements in order to capture these cost savings. However, this past practice means that every well-maintained unit likely has implemented several cost-justified methods to improve heat rate, and that only marginal projects remain for consideration.

Existing coal-fired generating units are also constrained by their original design basis and past operations. Units vary significantly due to their design, manufacturer, operating history, age, and type of coal consumed, among many other factors. It is completely unreasonable and technically infeasible to expect that this widely diverse fleet could all achieve the same level of improvement in heat rate performance. For example, the AEP John W. Turk, Jr. Plant ("Turk") that began operation in 2012 represents a state-of-the-art ultra-supercritical steam cycle, which is a design that produces higher steam temperatures and pressures than is typical in most units. The result is that the Turk Plant has a much higher overall efficiency (~38%) and much lower average net unit heat rate (~9,000 Btu/kWh net), than the 2012 coal-fired generation fleet average of 34 % and 10,107 Btu/kWh net.[201] Turk is the only operating ultra-supercritical unit in the U.S., in large part because it has only been within the last decade that advanced steam piping materials have been available. EPA's flawed "one-size-fits-all" approach in building block one (a) incorrectly assumes that the newest and most efficient coal units, including the Turk Plant, could achieve a 6% heat rate improvement, and (b) ignores the significant unit-specific design differences that physically limit the potential opportunities for improvement.

Conversely, even similar or identical unit types can experience significant variability in heat rate performance. To support this point, the graph below plots the range of gross annual unit heat rates from 1999-2013 of AEP units that are of similar size and/or design. The units at each respective plant below, while sharing similar attributes in terms of the equipment technology and vintage, location (ambient temperature), fuel supply, operational characteristics, and other factors, have experienced quite dissimilar average gross annual heat rates, attributable to many of the factors discussed herein. Even similar units operating under similar ambient conditions can have significant variations in heat rate.

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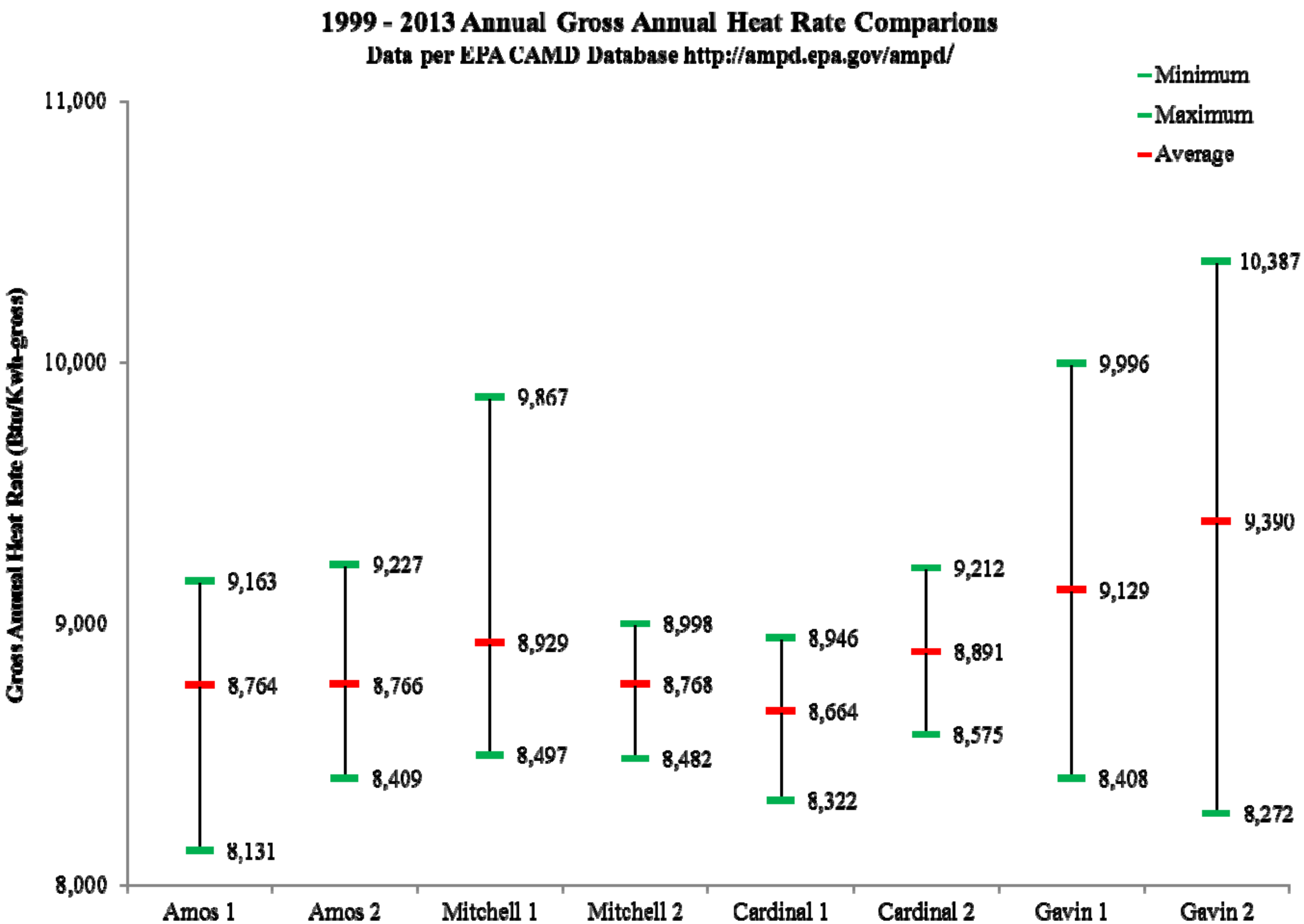
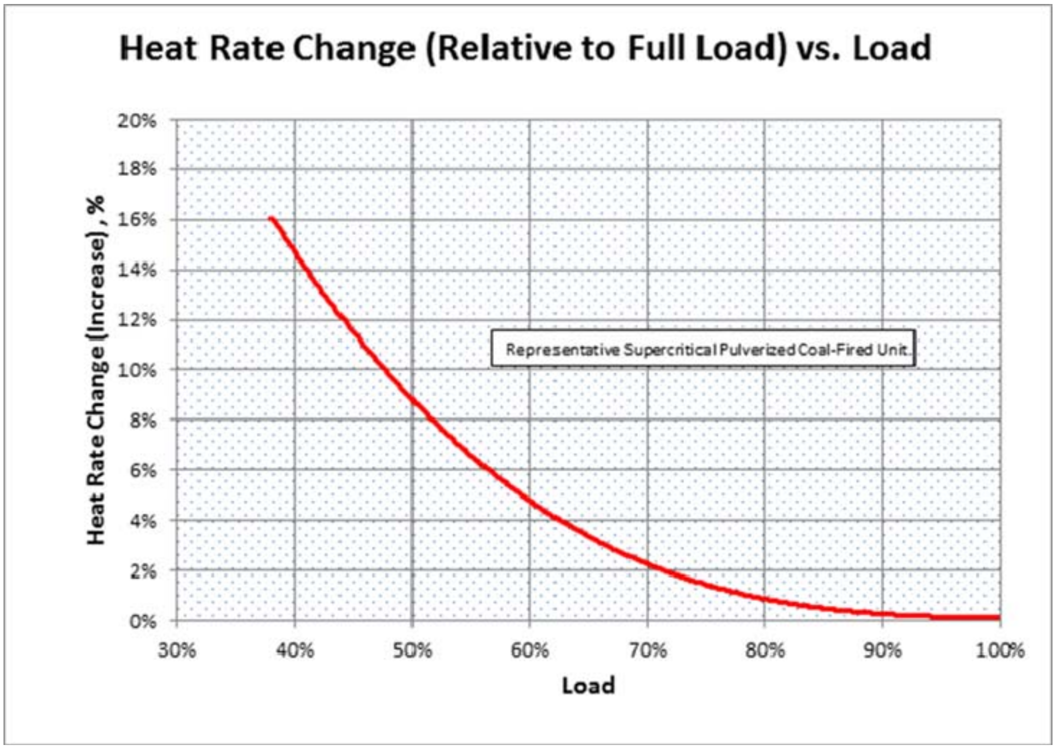
[201] U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'


1999 - 2013 Annual Gross Annual Heat Rate Comparions
Data per EPA CAMD Database http://ampd.epa.gov/ampd/
Minimum
Maximum
Average
Gross Annual Heat Rate (Btu/Kwh-gross)
11,000
10,000
9,000
8,000
9,163
8,764
8,131
9,227
8,766
8,409
9,867
8,929
8,497
8,998
8,768
8,482
8,946
8,664
8,322
9,212
8,891
8,575
9,996
9,129
8,408
10,387
9,390
8,272
Amos 1
Amos 2
Mitchell 1
Mitchell 2
Cardinal 1
Cardinal 2
Gavin 1
Gavin 2

It is important to differentiate between the "design heat rate" and the average heat rate of a unit. Design heat rate is a theoretical target that represents an optimal, full-load, steady-state condition and is considered the best level of unit performance that could potentially be achieved under original design conditions. It is possible that units may achieve their design heat rate when new with all components in their best condition. It is well-understood by manufacturers, operators, and most regulators, however, that the unit will not, and should not be expected to achieve its design unit heat rate under all operating conditions or throughout its operating life. The age of the unit, historic operations and maintenance over its life, as well as the retrofit of any auxiliary equipment like emissions controls, will all negatively impact the heat rate over the life of the unit, resulting in an average unit heat rate that is higher than the unit's original design heat rate. While there may be similarities between units, often even identically designed units at the same plant site have very different heat rates because each unit has been operated and maintained differently.

2. Actual heat rate performance varies due to a number of known and unknown, controllable and uncontrollable factors

Heat rate is *not* a constant value. It varies significantly due to numerous factors that both positively and negative impact performance. Heat rate is an operating variable that is constantly changing as the dynamic conditions of an individual unit's operating environment change. Heat rate is like the fuel efficiency rating of an automobile (typically expressed in miles per gallon or MPG), which is widely recognized to be affected by the conditions of "city" versus "highway" driving. The frequent stops, starts and speed changes associated with city driving result in higher fuel usage, whereas driving on a highway at a constant rate of speed with fewer changing conditions uses less fuel. Variability in operations or operating at less than "full load" have similar impacts on a generating unit. The relationship of unit load to heat rate is shown for a typical supercritical unit in the graph below. As a unit cycles loads up and down, or runs at minimum loads for which the unit was not optimally designed, heat rate increases significantly.




City and highway driving is not the only variable that impacts an automobile's fuel efficiency. Things like the basic aerodynamic design of the car, the condition of the road (wet vs. dry; gravel vs. pavement; uphill vs. downhill), the air pressure in the tires, the cleanliness of the engine's air and fuel filtration systems, the fuel type, and even the outside air temperature and humidity can all impact the fuel efficiency of an automobile. Likewise, heat rate can be impacted by process and equipment design, maintenance and cleanliness of critical components, changes in weather conditions, changes in fuel energy content or fuel delivery, changes in process water and cooling water temperatures, and other factors.

Although EPA attempted to identify operational practices and equipment upgrades that affect heat rate performance, the agency failed to fully consider the range of variables that drive performance, incorrectly identified the level of improved performance associated with the variables considered, and erroneously concluded that all existing coal units could achieve the same level of improvement from implementing a common set of measures. EPA must broaden its analysis of heat rate improvement opportunities to more accurately evaluate the range of unit-specific factors that impact performance.

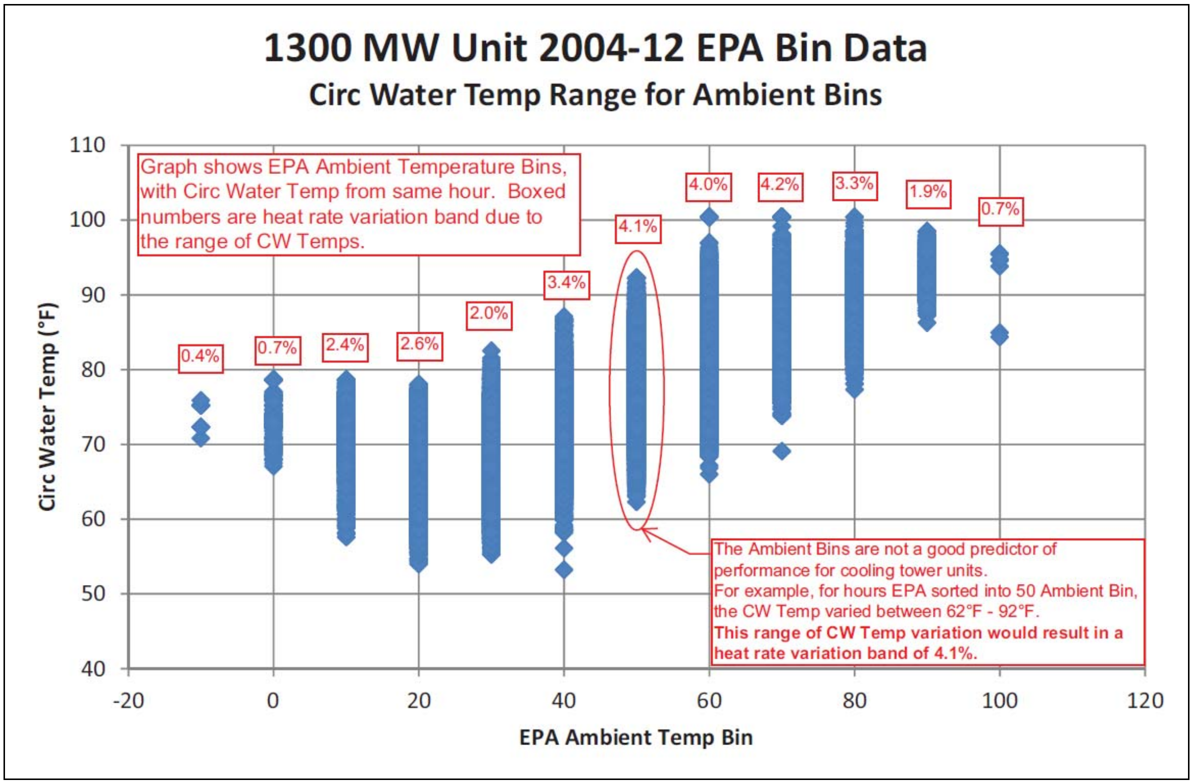
### 3. EPA has overstated the potential heat rate improvements related to operating practices

EPA attempted to evaluate the variability in unit heat rates related to operational practices by performing a statistical analysis (e.g. "bin analysis") of heat rate data at 884 coal- and petcoke-fired generating units from 2002-2012. Based on this analysis, EPA determined that application of "best operating practices" can improve heat rate by 4%. However, EPA's bin analysis is poorly designed and plagued with data scope and data quality issues that render it unsuitable as a foundation for any meaningful conclusions. As discussed in the sections that follow, EPA's determination is incorrect and significantly overstates the technical potential and understates the cost of such improvement opportunities, while ignoring significant feasibility, sustainability, measurability, and regulatory challenges.

#### a. The design of EPA's statistical analysis is fundamentally flawed

EPA's statistical analysis is fundamentally flawed, in part, because it assumes there is a strong correlation between heat rate and only two other factors: unit load (utilization) and differences in ambient air temperature. While EPA has correctly identified unit load as a key variable influencing unit heat rate, its assumptions about the impact of ambient air temperatures are not accurate. In reality, cooling water temperatures have a much stronger correlation with unit heat rate differences. Cooling water temperatures directly affect a unit's ability to remove/recover heat in the thermal cycle. Ambient air temperatures eventually affect cooling water temperature, but relatively quick changes in ambient air temperatures do not result in equally rapid changes in the temperature of a cooling water body. For example, warmer weather in the early spring does not initially elevate cold circulating water temperatures; or vice versa, colder early fall days will not immediately reduce warm circulating water temperatures. Similarly, day-to-night ambient temperature variations were used to sort the hourly data collected by EPA without regard to their actual ability to impact heat rate. These realities skew the temperature "bin" data analysis performed by EPA significantly. The figure below shows the wide range of circulating water temperatures associated with the "bins" EPA created based on hourly ambient temperature data. During the hours sorted into EPA's 50 degree Fahrenheit ambient temperature bin, the circulating water temperature varies from 62 degrees Fahrenheit to

92 degrees Fahrenheit. For some "bins," the circulating water temperatures varied by as much as 34 degrees Fahrenheit.




EPA oversimplified its analysis approach by simply aggregating data based on ambient air temperatures and unit load, then assuming that any remaining variability is under the control of unit operators. Such a simplified approach arbitrarily ignores the role that other variables, like circulating water temperature, play in heat rate variability. In the above graph, the variation (%) in heat rate within each temperature bin directly corresponds to the widening range in recorded circulating water temperatures within each ambient bin, suggesting a stronger correlation between heat rate and circulating water temperature, than ambient temperature. The above graph does not suggest that EPA could simply replace ambient temperature with circulating water temperature in its analysis, but is used to point out that EPA dramatically oversimplified its analytical approach to explaining controllable heat rate variability. The Utility Air Regulatory Group (UARG) performed a detailed critique of EPA's statistical bin analysis.[202] Using

[202] Cichanowicz & Hein. "Critique of EPA's Statistical Evaluation Defining Feasible Heat Rate Improvements." Prepared for UARG. December 1, 2014.

information provided in the EPA-referenced GHG Technical Support Document (TSD), UARG successfully reproduced the EPA results. However, UARG further evaluated the units within the EPA bins and discovered that significant design differences (e.g. unit age, steam cycle design, capacity factor, cooling system design) exist between the analyzed units.[203] These design differences contribute to the heat rate variability, and cannot necessarily be mitigated through "best practices" or heat rate improvement projects. Consequently, EPA's estimate of potential improvement opportunities is flawed and inaccurate.

EPA's calculation of its coefficient of determination or the "r-squared" value (0.26), which describes the relationship of unit load and ambient temperature, reinforces this conclusion, as these variables only account for 26% of the variability in overall heat rate of the population.[204] EPA should have stopped there, since 74% of the variability in heat rate is unexplained. Instead, EPA relied upon these two variables as a basis to identify available heat rate improvement opportunities. EPA's failure to examine other contributing uncontrollable factors leads to a significant overstatement of heat rate improvement opportunities.

UARG's replication of the "r-squared" value using the EPA data, along with further analyses of the unit designs and other contributing factors to heat rate significantly weaken EPA's assertion that unexplained heat rate variability represents the potential for improvement. Not only did EPA's analysis not fully account for the role of load and ambient temperature, but also several other variables were ignored – most significantly boiler design differences and coal composition. Boiler type (e.g. subcritical, supercritical, ultra-supercritical), along with size, age, and ability to respond to load changes all will have impact on heat rate. Coal composition can affect heat rate through boiler thermal efficiency and slagging impacts, changes in flue gas moisture content, and auxiliary power requirements. If EPA bases its final guideline on the existence of heat rate improvement opportunities, then the agency must reject the bin analysis and revisit its methodology for determining potential heat rate improvements through "best operational practices." Such a revised analysis must more accurately account for unit-specific

[203] Id. P. 6-8.
[204] U.S. EPA Office of Air and Radiation. GHG Abatement Measures. Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units. Docket ID No. EPA-HQ-OAR-2013-0602. June 2014. p. 2-24

design differences and be premised on factors that more directly affect unit performance and accurately reflect available opportunities for improvement.

EPA's evaluation of historic heat rate data is also biased by the inclusion of units that have been or will be retired before the first compliance period. Many of these retiring units were designed with less efficient processes (no reheat cycles, subcritical designs, and age-related operational constraints) which suggests a larger amount of heat rate variability and potential opportunities for improvement, than is present for the high-performing units that are suggested to remain in-service when the rule becomes effective. Units that are retired or that will be retired before 2020 should be excluded from the analysis to ensure that the evaluation reflects only those potential opportunities that may be available on the units that will remain in operation during the period affected by the guidelines.

b. EPA's dataset contains inherent sources of variability

EPA used data reported to the Clean Air Markets Division (CAMD) over the period from 2002 to 2012 as the basis for its statistical analysis of heat rate variability. Originally designed to capture emission data to support the emission allowance trading program created by the 1990 CAA Amendments, the requirements for reporting data to CAMD have evolved significantly over time. Many changes have occurred over this period that contribute to the variability in the heat rate data, yet these inherent sources of variability were not addressed in EPA's analysis:

- Continuous Emissions Monitoring Systems (CEMS) Flow monitor changes/upgrades. Allowable switching between redundant monitors and acceptable calibration ranges could result in as much as a 3% change in flow.
- Measurement instrumentation and locations may have changed as a result of emissions controls retrofits or other changes which may have occurred on the units.
- In 2008 EPA changed its fuel-specific emission factor (F-factor) requirement for CEMS reporting. On units firing bituminous fuel, this change would be interpreted as a 2% increase in heat input (2.2% degradation of heat rate).
- EPA's QA/QC steps and overall processes for reporting data have evolved over the years. Data from 2009 forward is likely to be the most homogeneous because of more widespread use of Emissions Collection and Monitoring Plan System (ECMPS) by reporting sources.
- Allowable Relative Accuracy Test Audit (RATA) flow instrument recalibration is typically less than +/-7.5%, but can be +/-10% or more.

These changes contribute to the overall range of variability in unit heat rates calculated based on the CAMD data and undermine the validity of EPA's analysis to determine an across-the-board recommendation for heat rate improvement. EPA made no effort to identify the effect of these changes in data reporting protocols, or to eliminate their impact before determining the range of potential heat rate improvement at coal-fired power plants.

### c. EPA failed to account for physical and operational changes at existing units that affect potential heat rate improvement opportunities

The potential for future heat rate improvements depends on the current physical and operational characteristics of the existing fleet. By way of analogy, replacing the air filter in your car can improve fuel efficiency, typically at higher vehicle speeds. However, if the highway by which you commute to work is suddenly closed and you are rerouted through busy city streets, any fuel efficiency improvement from the new air filter will be overwhelmed by the result of more "city" driving. Similarly, if improvements are made to components or systems within a power plant, and then the unit is cycled more frequently to balance intermittent loads from new wind and solar generation, the effect of the heat rate improvements may never be measureable. In fact, depending upon the situation, the unit's average heat rate might actually deteriorate.

EPA's heat rate improvement determination was based on an analysis of gross heat rate data for a large population of units over a ten-year period. However, EPA did not consider or account for the many physical and operational changes that occurred over this period, and that have a direct affect on heat rate. Specifically, EPA should have considered heat rate changes from the installation of new emission control systems, prior heat rate improvement projects, and changes in duty cycle before estimating any remaining potential for heat rate improvements at existing coal-fired units.

Installing and operating emission control systems can often mask or offset any future heat rate improvement actions. From a net unit heat rate standpoint, these systems have a direct impact as the auxiliary power requirements reduce the amount of net energy (MWh) produced. The retrofit of selective catalytic reactors (SCRs) consumes on average about 1.5% of net output. The retrofit of flue gas desulfurization (FGD) systems on units fired by subbituminous coals increases auxiliary power usage by approximately 1.5%, while retrofits on units firing bituminous coals or a blend of these fuels increases auxiliary power usage by approximately 2.5%. In addition, a limestone-based wet FGD system introduces additional $CO_2$ into the flue gas stream as a result of chemical reactions in the scrubber, which increases the $CO_2$ content of the gas stream by several percentage points, in addition to the increase in auxiliary power requirements. There may be ways to minimize the detrimental heat rate impacts of adding these systems (e.g. employing efficient axial fans, considering variable speed drives where practical, optimizing ductwork configurations, etc.), but these design options are site-specific, and in no case are they enough to offset a net heat rate increase from the addition of these control systems. All of these changes affect heat rate, but do not "create" any additional heat rate improvement opportunities. EPA's analysis failed to eliminate these causes of heat rate variability, and thus overstates the remaining opportunities for improvement. For units with current obligations for future emissions control system retrofits, the adverse impact to net heat rate (2-4%) from the control installations makes a 6% improvement in heat rate even more unachievable.

Many units have already undertaken equipment upgrades and as such, the potential for additional improvement is marginal. Steam turbine upgrades represent the most significant heat rate improvement option available to the industry and to date, 86% of AEP's coal-fired generating capacity that will still be in service in 2020 and beyond undertook steam turbine upgrades prior to 2012. These units would receive no credit for these upgrades, and have limited options for additional heat rate improvements since turbine upgrades are generally the most effective heat rate improvement option available to reduce emissions.

It is standard practice in the utility industry to utilize preventative maintenance and routine cleaning practices that promote and sustain efficient operations. AEP, along with other utilities, the Electric Power Research Institute (EPRI), and power plant system original equipment manufacturers (OEMs) have for years participated in industry workshops, users group meetings and other forums to share best operating and maintenance practices to improve overall plant performance. Many of these targeted efforts have specifically focused on improving heat rate, i.e. reducing the amount of fuel consumed to generate electricity, thus lowering operating costs. Yet, the CPP offers no credit for proactive efforts like these, and the amount of heat rate improvement contemplated by EPA is very aggressive and overly ambitious for units that have historically been well maintained and operated. For recently constructed coal units that were built with more advanced and more efficient technologies, many of the potential heat rate improvement opportunities have already been incorporated into their base designs. Any potential improvement opportunity will be minimal and certainly far from the 6% level that EPA has considered in the proposed rule.

EPA's analysis also failed to consider unit operational changes that have occurred and will occur if the CPP is implemented as proposed. Many coal-fired units have gone from being base-loaded to load-following or cycling units, based on market/economic conditions or other factors. As such, the heat rate of a unit can change significantly, reflecting these operational changes. EPRI issued a report in 2011 which outlined the effects of cycling on heat rate. The report studied a 700 MW coal-fired unit which ran base-loaded (usually operated at net loads at or above 650 MW) from January to August of 2008. From August through the end of 2008, the unit was cycled frequently to follow the demand for generation. Average net unit heat rate during the months when the unit was cycled increased by 2.3%.[205] The unit continued to cycle with generation demand through 2010, and over the operating period from 2008-2010 the plant initiated programs to target heat rate improvement. EPRI performed an initial assessment of the plant's "heat rate culture" and found that many of the heat rate best practices were already in place at the plant. On the basis of the EPRI assessment, the plant took additional actions which included:

- Formation of heat rate teams to brainstorm heat rate improvement ideas and monitor performance;
- Implemented daily, weekly and monthly reporting of key performance indicators;
- Offered refresher training to operators on heat rate awareness;
- Completed routine equipment and site walk-downs targeting equipment and component maintenance and cleanliness;
- Improved management of excess air on the unit; and
- Improved coal sampling techniques.[206]

Average net unit heat rates in 2009 and 2010 were only about 1% above the average heat rate for when the unit operated as a base-loaded unit.[207] However, this is a good example of how implementation of best-practices and diligent attention to improving heat rate could not overcome the 2.3% heat rate increase brought about by increased cycling of the unit.

[205] "Cycling and Load Following Effects on Heat Rate." Electric Power Research Institute. July 2011. p.4-1 .
[206] Id. p. 3-33 & 3-34.
[207] Id. p. 3-32.

### B. EPA has overstated heat rate improvements related to equipment upgrades

EPA determined potential heat rate improvement opportunities related to equipment upgrades based on a review of engineering studies, an evaluation of year-to-year performance trends, and an analysis of data from units identified by EPA that allegedly demonstrate that such improvements are achievable. For each of these areas, EPA generalized data and assumptions on potential heat rate improvement opportunities and concluded that a 2% improvement from equipment upgrades is achievable across the U.S. coal fleet without any serious consideration of unit-specific factors. EPA's determination significantly overstates the technical potential and cost of such improvement opportunities, while ignoring significant feasibility, sustainability, measurability, and regulatory challenges.

#### 1. The 2009 Sargent & Lundy study does not support EPA's BSER determination on heat rate improvements from equipment upgrades

S&L has publicly stated in correspondence with National Rural Electric Cooperative Association (NRECA) and the Utility Air Regulatory Group (UARG) that EPA mischaracterized their 2009 report, entitled "Coal-Fired Power Plant Heat Rate Reductions," and that the report does not in any way support a conclusion that any individual coal-fired unit or any group of coal-fired units can achieve 6% heat rate improvement. S&L goes on to say:

- The results were based primarily on publicly available and conceptual data from equipment suppliers and in no way concluded that the options examined could be applied at each and every unit, but rather each option would need to be explored on a unit-by-unit and case-by-case basis to determine the applicability and feasibility.
- The two specific heat rate improvement case studies presented in the report were estimated at a conceptual level, and were not based on detailed unit-specific analysis. Verification of the improvements was not carried out to determine what, if any, actual heat rate improvements were realized.
- Combinations of strategies to achieve heat rate improvements do not always provide improvement reductions equal to the sum of each individual strategy's heat rate improvement because of inter-related plant operational variables.
- The performance of evaluated heat rate improvement strategies degrades over time, even with best maintenance practices.
- The benefit of heat rate improvement is reduced at lower operating loads. Therefore, a unit which undergoes a switch from base-load operation to cyclical or load-following operation will see an increase in annual average heat rate and the improvement strategy or strategies implemented are unlikely to make up the

difference. In some cases, any heat rate improvements achieved through options described in the 2009 report could be negated by load-cycling losses.

- Based on S&L studies, it appears most utilities are already employing best operational and maintenance practices and further significant reduction in heat rate may not be feasible.[208]

AEP completed a fleet assessment based upon the options suggested in the 2009 S&L report to determine, at a high level, the applicability and potential for further improvement on the fleet. Many AEP units have already implemented many of the improvement options as part of targeted performance improvement efforts, or simply as "business as usual" maintenance and due diligence. As a result, AEP supports S&L's conclusions that further reductions in heat rate are not technically achievable or feasible. The table below summarizes AEP's review of the applicability of the heat rate improvement strategies identified by the S&L report.

[208] Letter from Raj Gaikwad, Ph.D, Vice President Advanced Fossil Technologies, Sargent & Lundy, LLC to Mr. Rae Cronmiller, Senior Principal Environmental Counsel, National Rural Electric Cooperative Association.

| HR Improvement Strategy | Sargent & Lundy Description | Applicability to AEP Units |
|---|---|---|
| Boiler Island – Materials Handling (fuel and ash) | Variable frequency drives provide no substantial reduction in plant heat rate. Pulverizer upgrades warranted only if facility is switching fuels. Ash handling is not considered a prime area of investment for plant heat rate reduction. | Variable frequency drives provide very limited benefit to systems which are NOT frequently cycled but operated at a steady output. Targeting such systems can provide small incremental benefit, but likely minimal measurable improvement to overall heat rate. |
| Boiler Overhaul | Major changes to a furnace are not undertaken due to regulations currently in place (NSR enforcement). Economizer replacements do occur during some SCR retrofit projects. | Addressed with proper maintenance. Heat transfer sections within the boiler (economizer, superheaters, reheaters), when needed are usually replaced in-kind (no heat rate improvement). May offer some restorative impact on heat rate, but no significant improvement. |
| Neural Network | Used to optimize plant performance during load changes. | Neural Networks "tested" on several units. No substantial benefit could be derived. Biggest heat rate benefit derived by minimizing excess air levels (set by limits). NN provided no benefit beyond unit operators' abilities and available tools to monitor and control excess air. AEP has a Generation Fleet Monitoring and Diagnostics team with intelligent software that identifies/flags pattern changes in operation and communicates performance analytics and best-practices back to the fleet. |
| Intelligent Sootblowers | Applicable to units burning PRB and lignite fuels - engages DCS with system controls for the sootblowers. | Only high-slagging units will see heat rate improvements. AEP has considered intelligent sootblowers and several units employ advanced water cannons for online boiler cleaning and slag removal. This option is site and fuel specific (high-slagging fuels) and not feasible for all units. |
| Air Heaters | Replace seals to reduce leakage and examine during emissions controls retrofits. Control acid dew point, particularly in connection with SCR retrofits. | Flue gas $O_2$ monitoring in place at many facilities to identify seal and air in-leakage issues. Addressed as part of ongoing maintenance. |
| Turbine Overhaul | Degradation and improved designs can be addressed, but greatest reductions are associated with changes in design, and performance will degrade over time. | Generally seals wear uniformly over time and heat rate improvement degrades. Turbine overhauls are routinely evaluated for each unit on a techno-economic basis and conducted on a schedule. AEP has performed turbine upgrades on 86% of the fleet that will be operating beyond 2016. |

| HR Improvement Strategy | Sargent & Lundy Description | Applicability to AEP Units |
|---|---|---|
| Feedwater Heaters | Cost of increasing heat transfer surfaces is prohibitive due to small incremental reductions in heat rate. | No feasible measures identified. |
| Condensers | Regular cleaning schedule has varying impacts on heat rate depending on location and cooling water characteristics. | Back pressures routinely monitored and diligent maintenance programs already in place across the fleet to address issues as soon as reasonably possible. Condenser tubes cleaned as necessary. |
| Boiler Feed Pumps | Ordinary wear and tear degrades performance and is addressed during overhauls or upgrades. | BFP rotors are swapped out on routine schedules to maintain high feedpump efficiency. Turbine drives on many AEP feed pumps already incorporate VFD efficiency. |
| Fans and VFDs | Installation of upgrades usually made in connection with emissions controls. | Many units have installed high-efficiency axial vane ID fans as part of emissions control projects to offset a portion of the heat rate penalty of adding emissions control equipment. |
| Emission Control Technologies | Discussion of potential improvements associated improved control system designs and power management features. | Limited power management savings benefit available for vast majority of units. Often state implemented Compliance Assurance Monitoring (CAM) Plans prohibit the use of power management features. |
| Boiler Water Treatment | Most power plants already have advanced water treatment systems installed. | AEP maintains very tight control over boiler water chemistry standards. Well defined corporate oversight program in place to insure high performance and high reliability. |
| Cooling Water Treatment | Proper maintenance of water quality in the cooling system maintains efficiency that could be lost through fouling. | Proper maintenance procedures are in place for cooling water treatment. Cells taken out service during part load and cool periods (auxiliary power management). |
| Advanced Cooling Tower Packing | Optimization of cooling water temperatures and fan requirements must be conducted to investigate effectiveness of upgrading fill or implementing VFDs for older fans. | High efficiency fills have proven to be problematic and susceptible to fouling thereby increasing heat rate. High efficiency fills have actually been replaced on many cooling tower units and heat rate improved. Fans (cells) taken out of service to reduce auxiliary loads during part load and cool periods. |
| Other Improvements | Motor replacement programs can yield minor heat rate improvements. | Similar to the assessment of VFDs, motor replacements are assessed on a system by system basis to determine feasibility and benefits. |

2. EPA's review of other documents discussing heat rate improvements does not support the BSER determination on heat rate improvements from equipment upgrades

EPA TSD also references a NETL report, entitled "Reducing $CO_2$ Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet;" however, the link provided in the TSD is to a deck of slides and charts describing the NETL report, not the full report. No link is provided to the full report or any text which might explain the data in the slides. Additional searches to uncover the complete report were unsuccessful. Without the underlying text of the report, the administrative record is incomplete, and it is unclear as to whether NETL discussed the challenges and limitations to efficiency improvements.

A 2010 NETL report, entitled "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emission Reductions," examined 10 years (1998-2008) of unit efficiency data from 892 coal-fired units. While the report projected that efficiency improvements across the fleet were possible, key takeaways from the NETL analysis were:

- Load factors (ratio of average load to peak load) for the top decile of the units studied averaged 83%, meaning that these units, when operating, operated at nearly full load, and their performance would not be achievable by units operating at lower load factors.
- NETL acknowledged that quantification of the opportunity to improve efficiency could be improved by things such as:
  - Verification of the data;
  - Unit-specific data to enable estimation of the heat rates;
  - Estimates of the costs to improve efficiency; and
  - Case studies at specific units and computer models to provide more details into the opportunities to improve heat rate.[209]

The bulleted items above indicate that NETL had an appreciation for the variability, possible inaccuracy, and overall feasibility of the heat rate improvement potential which they analyzed. The report suggests that these items should be considered to better assess the improvement opportunity. EPA ignored such language in the NETL report and simply cited the report as a reference for their determination of achievable improvements.

[209] DiPietro & Krulla. "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions" – DOE/NETL April 16, 2010

EPA also cites a very brief two-page report, entitled "Reducing Heat Rates of Coal-Fired Power Plants," from Lehigh University, that relies upon high-level conceptual information regarding heat rate improvement options and very general reduction percentages.[210] The Lehigh report does a poor job of characterizing the unit-specific nature of heat rate improvements and fails to discuss factors that affect heat rate improvement. It does, however, accurately state that "it would not be possible to take full advantage of all possible improvements on every coal-fired unit," but does not provide any substantiated evidence as to what level of improvement is achievable. Examples provided in the report are largely comprised of unsupported conceptual estimates and/or limited operational data and there is no real data on which EPA could base any determination of achievable heat rate improvement.

A paper from Resources for the Future, entitled "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act," does not attempt to assess or evaluate what percentage of heat rate improvement exists on coal-fired generating units, but rather relies upon an EPA statement from the 2008 "Technical Support Document for the Advance Notice of Proposed Rulemaking for Greenhouse Gases: Stationary Sources," in which EPA then estimated that a 2-5% efficiency improvement was possible, along with additional references to the 2009 S&L report.[211] The authors do, however, acknowledge that "significant analysis and expertise are required to find the optimal combination of [heat rate] upgrades and techniques, *if any*, for each specific plant."[212]

The paper then goes on to consider how market and/or regulatory impacts might influence or "force" the realization of heat rate improvements. In similar fashion to other EPA references in the TSD, the entire report is based on the assumption that EPA's estimates for improvement potential from the measures discussed in the S&L report are achievable across the fleet, which is simply not the case.

NRDC prepared a report, entitled "Closing the Power Plant Carbon Pollution Loophole," that relies heavily on the same 2009 S&L report used by EPA in the proposed rulemaking to

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[210] "Reducing Heat Rates of Coal-Fired Power Plants" – Lehigh Energy Update. Vol. 27, No.1. Jan 2009.
[211] Linn, et.al. "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act" – Resources for the Future. February 2013.
[212] Id p.9 (emphasis added)

characterize and support its assumptions for heat rate improvement.[213] NRDC provided a table in Appendix V to show that the technical heat rate improvement options addressed conceptually in the S&L report were simply added to determine the total available heat rate improvement potential.[214] For reasons stated earlier in this report, this is simply not a practical feasible approach, and the S&L technical information was not intended to characterize the actual heat rate improvement potential for any one unit or group of units.

Other relevant reports and studies have been carried out that address the complexities, opportunities and challenges associated with heat rate improvements. EPA failed to consider these reports and the issues they raise. For instance, in 2009 and 2010, US DOE and NETL sponsored industry workshops specifically targeted toward opportunities to improve the efficiency (heat rate) of existing coal-fired power plants.[215],[216] These workshops brought together industry experts, utility owners and operators, equipment suppliers, consultants, industry associations, and research organizations to explore heat rate improvement. Key takeaways from the workshops were documented and several are listed below:

- "The heat rate of a coal-fired power plant is costly and difficult to accurately measure in real-time."
- "Better national data on plant efficiency is needed, but this is hindered by the variation in methods and accuracy for measuring plant heat rate."
- "Without adequate heat rate data, it will be difficult to monitor improvements in the overall efficiency of the U.S. fleet of coal-fired power plants."
- "Plant operators often lack sufficient monitoring tools or measurement frameworks to measure both baselines and future improvements for a given process."
- "The industry also lacks clear guidelines and standards for measuring and reporting efficiency improvements."
- "Hard to make a business case for something one cannot measure (heat rate)"
- Four of the top five barriers and challenges identified that inhibit the adoption and application of technical options to improve heat rate were:
  - Age of fleet prevents significant changes
  - Inability to compare plants on a similar basis

[213] Lashof, et.al. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters" – NRDC. March 2013.
[214] Id. Table V.1. p. 69
[215] Eisenhauer & Scheer. "Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants." NETL Technical Workshop: July 15-16, 2009.
[216] Brindle, et.al. "NETL Technical Workshop Report: Improving the Thermal Efficiecny of Coal-fired Power Plants in the United States." February 24-25, 2010.

- Difficult to measure improvement and monetize benefits
- Efficiency is limited by exiting design

These issues and concerns still exist, and further support the fact that achieving, measuring, and sustaining a 6% heat rate improvement across the fleet is simply not practical.

3. The unit-specific examples identified by EPA do not demonstrate that its heat rate improvement targets are achievable or adequately demonstrated.

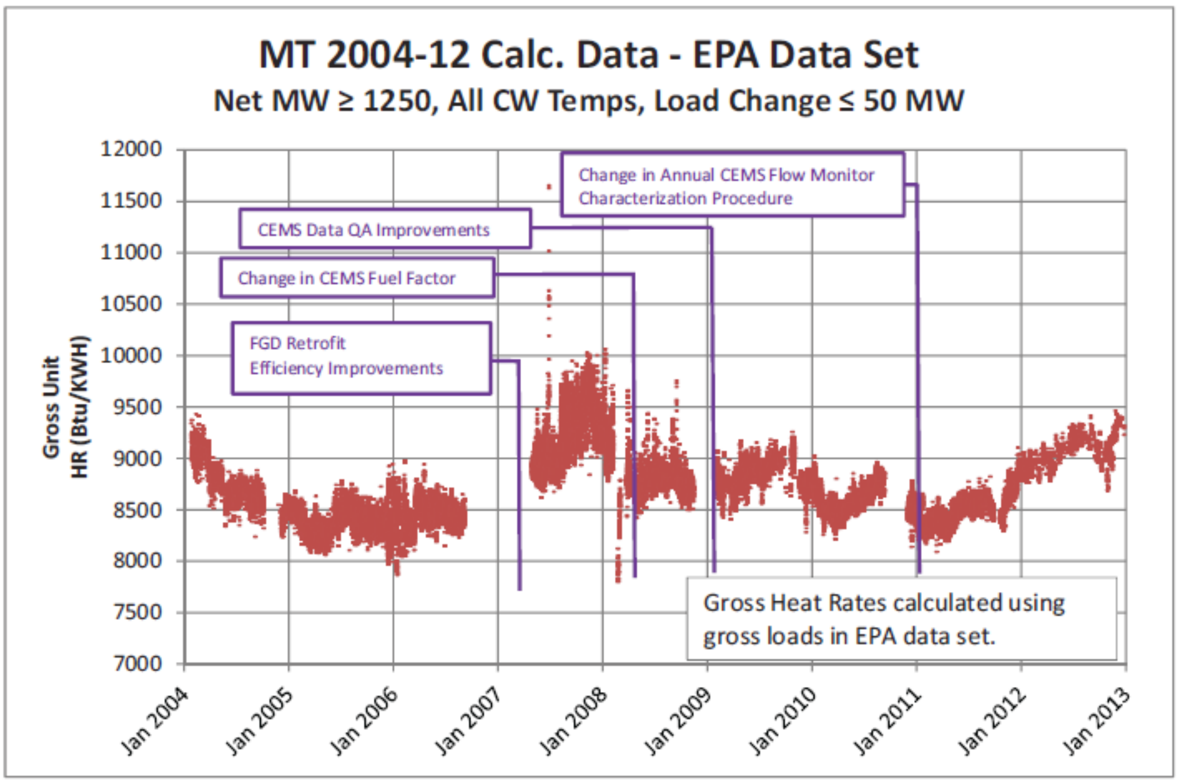
EPA identified 16 units, based on the results of its statistical analysis, that EPA concludes are examples of equipment upgrades that achieved 3-8% gross heat rate reductions. EPA claims that after accounting for "capacity factor, reporting method, or other events," these 16 units emerged from the national inventory and reported a single year-over-year improvement in gross heat rate of at least 3-8%. The sixteen units, owned by twelve utilities, were identified in a table posted in the rulemaking docket. UARG contacted and received technical responses from 10 of the 12 owners, addressing 14 of the 16 units.[217] The UARG investigation found that:

- Eight owners of eleven units report all changes are due either exclusively or almost exclusively to variability in CEMS heat input measurements. The most frequently cited CEMS-based action was the routine calibration of the stack flow monitor in conjunction with an annual relative accuracy test audit ("RATA"). The units reporting this experience are Rodemacher unit 2; Valmy unit 2; Southwest unit 1; Johnson unit 2; Sheldon unit 1; Bridger unit 3; Colbert units 1-3; Weston unit 3; and Gorgas unit 2.
- Five units reported that upgrading the steam turbine appeared to lower gross heat rate, with modest payoff of approximately 3%. However, at three units this benefit was more than negated by an increase in net heat rate due to retrofit of environmental controls. Specifically, the Gibson unit 1 incurred higher net plant heat rate starting in 2007, when FGD was retrofit and gas handling was changed to employ a single dedicated stack. Petersburg unit 2 similarly observed a net heat rate increase in 2005, following retrofit of SCR in 2004. In 2007, King unit 1 completed a significant rehabilitation of the unit, including a new steam turbine, feedwater heaters, circulating water system upgrades and coal handling upgrades as part of a project to add SCR, FGD and fabric filter to the unit for emissions controls. The upgrade of the steam turbine and other components improved heat rate by 2.7% but was offset by the losses imposed by the addition of the emissions controls equipment.
- Southwest unit 1 upgraded its steam turbine in 2010, and a pre- vs. post-upgrade comparison suggests this action delivered a gross heat rate reduction of 2%. However, the accuracy of the CEMS-informed heat rate improvements is questionable - the same

[217] Cichanowicz & Hein. "Critique of EPA's Use of Reference Units to Select Heat Rate Reduction Targets." Prepared for UARG. November 25, 2014.

data suggested a 15% heat rate reduction from 2002 through 2008, when no actions were taken.[218]

The preceding observations suggest that CEMS-derived heat rate data is more often influenced by changes to reporting methods, and not proactive steps to lower heat rate. AEP charted a similar experience at its Mountaineer Plant. Full load gross unit heat rates calculated from CEMS data were charted using hourly gross loads from the EPA dataset. As the graph below shows, a more significant reduction in heat rate occurred as a result of CEMS measurement procedure changes than occurred with efficiency improvement projects which coincided with the FGD installation.




4. EPA fails to adequately address NSR-related issues that challenge the efficacy of heat rate improvement opportunities.

EPA acknowledges that many of the heat rate improvement projects involve equipment replacements or upgrades that have been targeted in suits filed by EPA and citizen groups under the new source review ("NSR") provisions of the Clean Air Act. These suits claim that by

[218] Id. p. 3-24

improving unit efficiency, operators will run units for more hours during the year, increasing annual emissions above the thresholds that trigger an NSR permitting obligation. These suits have resulted in widely differing opinions about what remedies are barred by the statute of limitations, how to interpret the exclusion for "routine maintenance, repair, and replacement," and how to calculate emissions before and after an efficiency improvement project. EPA offers no relief from NSR enforcement for operators who seek to comply with the Clean Power Plan by improving unit efficiency, and without such relief, many operators will be reluctant to engage in more expensive efficiency improvements like turbine replacements and other equipment upgrades that offer the most cost-effective improvements.

Over 400 specific efficiency improvement projects of the type described in the S&L report referenced in the proposed rule have been identified based on a review of Notices of Violation ("NOVs") issued by the EPA, and complaints filed by the Department of Justice or environmental advocacy groups alleging violations of the NSR permitting program for failing to obtain a permit prior to undertaking equipment replacement or other heat rate improvement projects at EGUs.[219] Those NOVs and complaints also identify another 600 equipment replacement or repair projects that involve other components not specifically identified in the S&L report or EPA's GHG Abatement Measures Technical Support Document. These allegations are not an indication that a violation actually occurred, but are an indication of the chilling effect that EPA's enforcement initiative will have on the willingness of EGU operators to pursue these or other heat rate improvement opportunities identified in EPA's GHG Abatement Measures Technical Support Document in the absence of clarification from EPA that these activities will not trigger NSR permitting requirements.

The first element of an NSR-triggering change mentioned by EPA in the preamble, a "physical or operational change," is a phrase in the statutory definition of "modification" in section 111(a)(4), incorporated by reference in sections 169(2)(C) and 171(4).[220] EPA has interpreted that phrase in notice-and-comment rulemaking, going back to the 1970s, to have some common-sense exclusions.[221] It is well within EPA's discretion to add to its existing exclusions from the meaning of "modification" and/or "physical change or change in the method

[219] See Appendix A for the list of heat rate improvement projects that have been the subject of EPA enforcement actions.
[220] 42 U.S.C. §§7411(A)(4), 7469(2)(c), and 7471(4).
[221] *See*, *e.g.*, 40 C.F.R. §§ 60.14(e) and 52.21(b)(2)(iii).

of operation" those efficiency improvements an affected EGU makes in furtherance of a section 111(d) plan pursuant to EPA's Clean Power Plan. If EPA does not eliminate the risk of NSR applicability for building block 1 heat rate improvements, then the agency needs to reevaluate its proposed BSER and repropose appropriately revised emission guidelines.

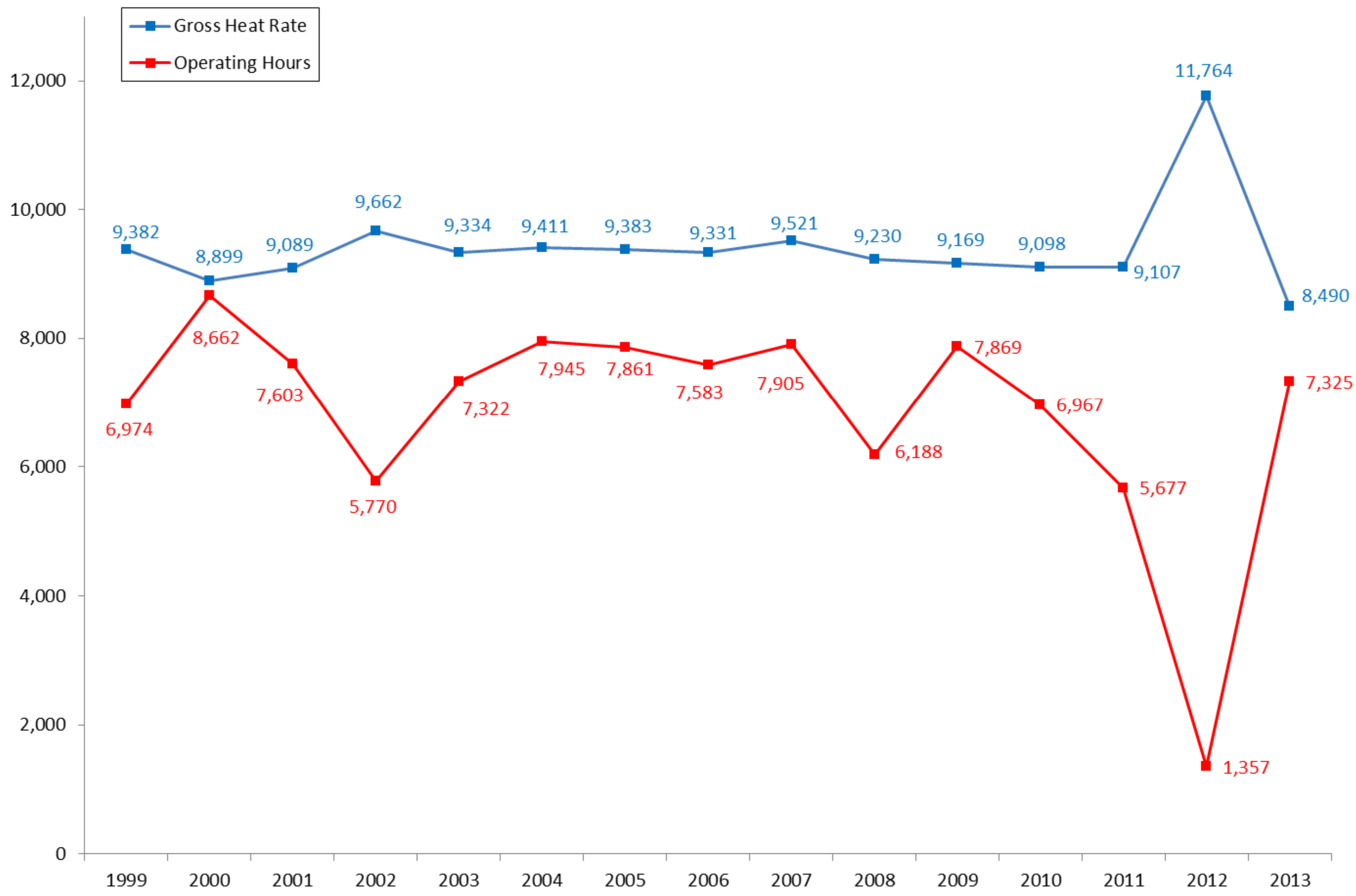
### C. EPA fails to evaluate whether the 2012 heat rate data is representative of typical unit operations or if the application of a 6% improvement is feasible given prior improvement efforts and historic unit trends

The use of any single year as a baseline for heat rate is not feasible or practical considering the vast array of variables that can impact heat rate on any given unit at any given time. If the baseline year happened to be a particularly unique year for an individual unit, any heat rate improvement based upon that particular base year will not be meaningful. The graph below represents one particular unit's average gross annual heat rate from 1999-2013. Operation in 2012 happened to be anomalous for this particular unit, as equipment outages and maintenance issues kept the unit out of service much of the year, resulting in significantly lower than normal capacity factors and output factors. In 2013, the unit returned to more typical operations having incorporated no significant heat rate improvements. Yet, from 2012 data, it appears that the unit's heat rate improved on the order of 27%. This is but one example demonstrating the flaw in selecting a single baseline year. It also demonstrates why it is impractical to design, implement, and enforce heat rate limitations. In fact, a review of recent air permits for fossil fuel-fired electric generating units nationwide revealed not a single example of a heat rate limit.[222]

[222] Appendix D lists the permits reviewed and indicates the absence of any heat rate limitations.

# Cardinal 3 - Gross Annual Heat Rate 1999-2013

Data per EPA CAMD Database http://ampd.epa.gov/ampd

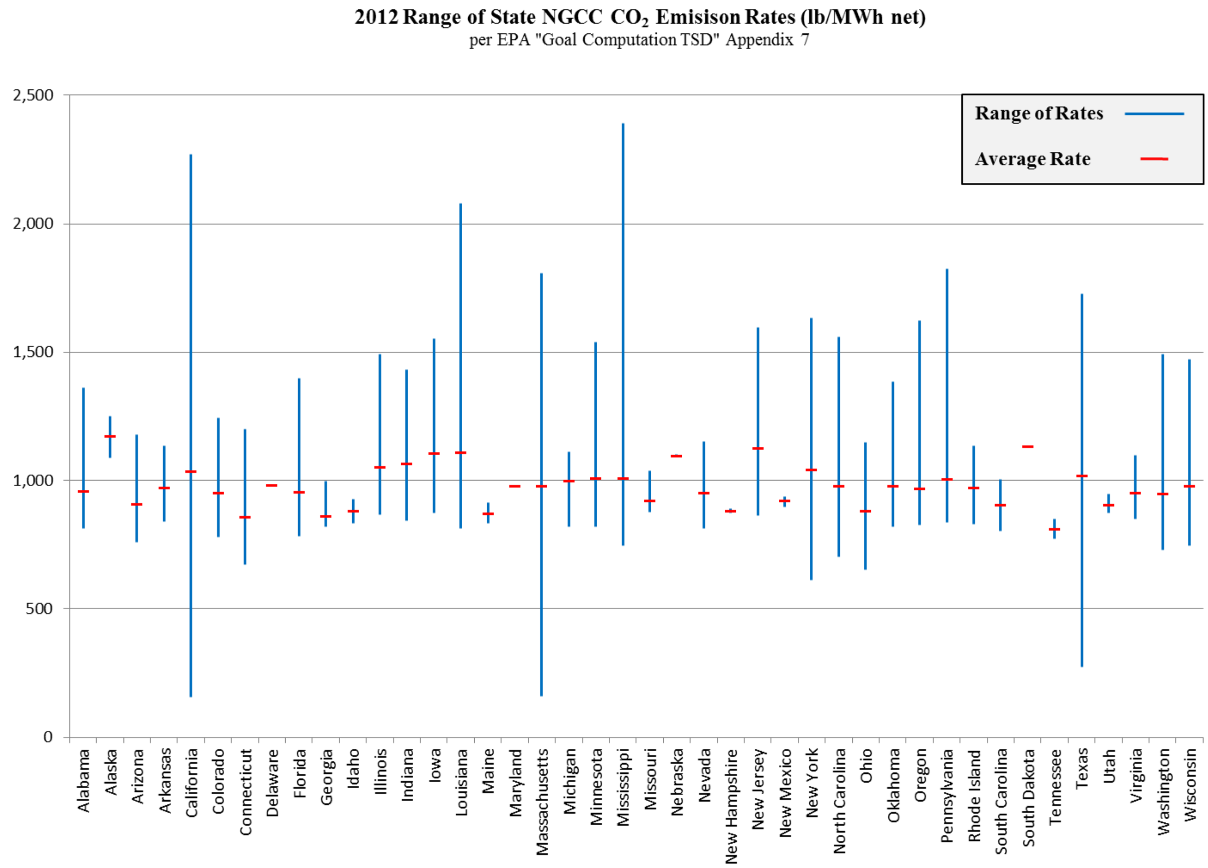


### D. EPA failed to examine heat rate improvement opportunities at other designated facilities

As with the Section 111(b) proposal for new sources, EPA has applied a double-standard when evaluating potential heat rate improvement opportunities for coal-fired units and other designated facilities. Although EPA discusses differences in the design, operation, age, and condition of the existing NGCC fleet, the proposed rule does not attempt to analyze whether any opportunity for improved efficiency exists, or, if so, how significant that opportunity might be. It is ironic that EPA is relying on increased utilization of NGCC resources, but has ignored whether or not those units are achieving optimal efficiency.

Based on a review of the data EPA relied upon to propose the state goals, it is readily apparent that the efficiency and performance of the existing NGCC fleet varies significantly within individual states and across the country.[223] The graph below is based on an analysis of unit-specific emission rates, and identifies the minimum, maximum, and average NGCC $CO_2$ emission rate for each state in 2012. The blue line represents the range of emission rates calculated, while the red marker is the average for the state.

[223] "State Computations TSD." Appendix 7. EPA. June 2014.




A number of potential opportunities to improve the performance of NGCC have been identified that are, at a minimum, worth evaluating. This includes opportunities related to turbine improvements and air cooling systems. These types of opportunities and others are discussed within various technical reports, such as the following:

- "Gas Turbines: How to Improve Operability, Output and Efficiency. Cogeneration & Onsite Power Production Magazine. (2010)
- "GE Combined Cycle Product Line and Performance." GE Power Systems. (2000)
- Bastianen & Voeller. "Economic Considerations for Gas Turbine Power Augmentation with Inlet Cooling." Energy-Tech.com. (2010)

### E. EPA should develop a work practice standard for heat rate improvements at designated facilities

Available information about the fossil units in the existing EGU fleet demonstrates that:

- There is a wide range of inherent limitations on the potential for heat rate improvements, including original design, geographic location, availability of space, emission controls, and prior improvement efforts;

- Unit efficiency naturally degrades over time;
- There is no accurate method to measure heat rate in real time;
- Heat rate improvements may be masked by control technology installations or changes in duty cycle; and
- Remaining useful life will affect the economic feasibility of continued efficiency investments.

Given these realities, there is no single emission standard or limitation that is achievable by or adequately demonstrated for the fossil fleet. However, there is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed the existing fleet to maintain and improve efficiency through adoption of best practices.

Section 111(h)(1) of the CAA authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof when it is not feasible to establish a standard of performance.[224] The phrase "not feasible to prescribe or enforce a standard of performance" means, for purposes of section 111(h)(1), that the "application of measurement methodology to a particular class of sources is not practical due to technological or economic limitations."[225] As applied to heat rate improvement opportunities, the Administrator could collect information on actual unit experiences associated with implementation of the suite of measures described in the S&L report and elsewhere, and develop a standard assessment for heat rate improvements that could be evaluated during regular planned outage cycles. Unit operators could submit a report and recommendation to the state that describes the measures evaluated, the lead time necessary to implement the project(s), and the relative cost-effectiveness of the recommended measures, based on the unit's remaining useful life. A reasonable cost-effectiveness threshold could be established, above which measures would not be required. Reports could be submitted to the state agency regarding implementation. In such a manner, available and cost-effective opportunities could be identified and implemented throughout the remainder of the existing units' operating lives. Actions taken to implement the CPP under such a work practice standard could be classified as "routine maintenance, repair and replacement," and thereby not expose unit operators to the risk of NSR enforcement. Such a standard would allow the greatest possible incorporation of efficiency improvements without disruption to the

[224] 42 U.S.C.§7411(h)(1).
[225] 42 U.S.C §7411(h)(2).

operation of the existing fleet, protecting electricity reliability and encouraging the development of new technologies. AEP respectfully requests that the Administrator consider the benefits of such an approach in finalizing the CPP proposal.

## VI. Building Block 2 Exceeds EPA's Authority and Is Based on Flawed Data and Methods

Building block 2 is based on EPA's generalized assumption that all existing NGCC units can be redispatched to sustainably achieve a 70% capacity factor. The analysis underlying this assumption is incomplete, relies on inaccurate data, and generally represents a poor understanding and application of the basic concepts and operating metrics used to assess historic and future unit performance. In addition, EPA fails to adequately define, let alone evaluate, significant technical, regulatory, legal, and practical factors that can and do impact the efficacy of the 70% assumption. The result is an assumed level of performance that simply has not been adequately demonstrated to be achievable across the fleet of existing NGCC units.

Further, an extensive number of methodological errors and data quality issues have been identified that erode the fundamental credibility of building block 2 *and* the entire proposal. Any attempt to correct the litany of concerns or determine how these corrections alter state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses is too complex to complete within the public comment period. Rather, it is EPA's responsibility to resolve these concerns and present a proposal that, at a minimum, is grounded upon accurate, complete data and conforms with acknowledged principles of mathematics and logic. Given the egregious nature and scope of concerns to be resolved in building block 2 *alone*, EPA has no other legitimate choice than to withdraw the current proposal, address these concerns, and publish a new proposed rule for public comment.

### A. EPA lacks the statutory and regulatory authority to redispatch EGUs

The dispatch of most electric generating units is controlled by balancing authorities, primarily Regional Transmission Organizations or Independent System Operators (generically referred to as "RTOs") according to market-based tariffs and operating agreements that are intended to capture the benefits of security constrained market-based economic dispatch across wide regions of the U.S. This allows for a more cost-effective operation of these collective assets for the benefit of the wholesale and retail customer.[226] RTO operations are based on agreements of the system owners and operators, and are subject to oversight by FERC, but even

[226] 16 U.S.C Section 824a(a).

FERC has no ability to compel any particular technique of coordination.[227] Indeed, no provisions of state or federal law have been identified that would allow EPA or the states to alter those arrangements and dictate a specific generation technique to achieve an arbitrary level of dispatch. The RTO energy markets have been carefully structured to achieve the least cost dispatch operation of committed generation, and to allow operators of individual units the flexibility to respond to dynamic and constantly changing circumstances in both the supply of and demand for electricity.

The comments submitted by EEI contain a detailed description of the functions performed by various generating resources as components of the bulk electric system and the detailed planning that must occur in order to accommodate changes in the location, type, size, and utilization of generation resources to assure the reliability of the electricity grid. Further, both transmission and natural gas pipeline capacity limitations could significantly impact the feasibility of achieving the capacity factors that EPA is targeting for NGCC facilities.

The comments submitted by UARG contain a detailed description of the authorities vested in the balancing authorities, RTOs, FERC and NERC under the Federal Power Act ("FPA")[228] for the coordination and operation of the interconnected grid. Section 201 of the FPA recognizes that federal regulation of interstate transmission of electricity is necessary in the public interest.[229] FERC has exclusive jurisdiction over all facilities for interstate transmission, and FERC has exercised that authority through orders and individual tariffs that mandate open access of the interstate transmission system to facilitate reliable and economic use of those facilities.[230] All practices of public utilities that significantly affect rates for wholesale power or transmission service must be filed with and approved by FERC.[231] FERC is authorized to revise any rate that it finds is "unjust, unreasonable, unduly discriminatory or preferential."[232]

Increasingly, FERC has relied upon market forces to ensure that rates are non-discriminatory and reasonable. The RTOs have assumed responsibility for economic dispatch of generation resources within their respective jurisdictions, subject to the terms of the agreements

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[227] *Atlantic City Elec. Co. v. FERC.* 295 F.3d 1 (D.C. Cir. 2002).
[228] 16 U.S.C.§824 *et seq.*
[229] 16 U.S.C.§824(A).
[230] *See, e.g.*, *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities,* Order 888, 61 Fed. Reg. 21,540 (May 10, 1996).
[231] 16 U.S.C. § 824d(c).
[232] 16 U.S.C. § 824e(a).

and tariffs that govern their operations. These agreements and tariffs are filed under Section 205 of the FPA, and are subject to FERC approval because of their significant impact on the rates and terms of service on the interstate electricity grid. Yet EPA fails to acknowledge that its limited authority under the CAA, and the responsibilities imposed on states as a result of the exercise of that authority, cannot interfere with or override these other federal authorities.[233]

Even if a mechanism existed through which NGCC facilities could be required to dispatch at capacity factors in excess of their historic rates, no certainty exists that increased utilization of those units would offset higher $CO_2$ emitting generation from existing facilities. The transmission grid is still largely based on connecting local loads to nearby generating assets, and is constrained in its ability to transmit power in ways that EPA never studied. Moreover, neither EPA, nor the states, have the authority to regulate emissions by creating a preference for one type of generating asset over another.[234] Even if each NGCC unit could achieve and maintain a 70% capacity factor that would exclusively offset higher $CO_2$ emitting generation within the state where it is located, the proposed rule ignores the realities of multi-state utilities whose generation is shared by retail and wholesale customers in multiple states. It also ignores the fact that multiple RTOs have control over transmission systems within the same state. For example, the state of Texas is included in four different regions: ERCOT, SPP, MISO, and WECC. None of these factors are adequately addressed in the proposed CPP.

**B. EPA has not demonstrated that a 70% capacity factor is achievable by all existing NGCC units**

The Clean Air Act defines a "standard of performance" as follows:

> a standard for emissions of air pollutants which reflects the degree of *emission limitation* achievable through the application of the best system of emission reduction which the Administrator determines has been *adequately demonstrated*.[235]

EPA has failed to adequately demonstrate that a minimum 70% capacity factor requirement has been achieved by any existing NGCC unit. Based on an AEP survey of over 300 air permits for coal and NGCC units, no examples have been identified of a specific requirement that establishes a minimum capacity factor from the regulated source.[236] In fact,

[233] 74 U.S.C.§7610(a).
[234] See the Legal Section for more information.
[235] 42 U.S.C. Section 7411(a)(1) (emphasis added).
[236] See Appendix D

EPA does not identify a single permit or regulatory obligation for an existing NGCC unit that establishes a requirement that the source achieve a specific capacity factor, let alone a 70% capacity factor. While certain units have operated at capacity factors at or above a 70% capacity factor because they were economical and otherwise available to run, this in no way adequately demonstrates that a minimum 70% capacity factor threshold could be manifested into a permit condition for any or all units that could be sustainably achievable across the range of operating, outage, and market conditions experienced over the life of a unit.

Building block two is focused on "increasing utilization, *to the extent possible*,...of existing natural gas combined cycle units."[237] EPA notes "[i]n order to redispatch....there needs to be some existing *unused generation potential* in the current NGCC fleet that could displace generation from more $CO_2$ intensive generating resources."[238] EPA erroneously interprets "to the extent possible" and "unused generation potential" to be the same for all units and applies a one-size-fits-all capacity factor that would be sustainably achieved by all existing NGCC units.

Such an approach ignores unit-specific factors that uniquely influence the potential amount of increased utilization that may be achievable by an individual unit. It is unclear why EPA gave no consideration to these unit-specific variables when the agency has previously acknowledged and analyzed such differences. In analyses supporting the Section 111(b) proposal, the agency notes that:

- ...some 1,000 [units] are NGCC located in 41 states and encompass a diverse population in capacity, years of service and configuration;
- NGCC technology performance and efficiency has improved over time;
- [NGCC units] fall into two groups: single-shaft...and multiple-shaft;
- The [study] population of 307 NGCC units [in-service since 2000] is heterogeneous in location, age, capacity, and operating profile;
- The study population includes...units that....were retrofits or conversions of simple cycle turbines to NGCC or that operated in single cycle mode for a period of time during commencement of operations;
- In general, smaller capacity NGCC units available on the market today are less efficient than the largest units; and

[237] GHG Abatement Measures TSD. EPA. 2014. p. 3-1. (emphasis added)
[238] Id. p. 3-5. (emphasis added)

- The average capacity factor from 2007-2011 of "small units" is 27% versus 36% for "large units.[239]

The EPA study identified a number of differences among NGCC units commissioned from 2000 to 2010. However, these differences become even more pervasive when considered across the entire fleet, which encompasses units commissioned from 1949 through 2014. These units represent a wide spectrum of process designs, business models, regulatory requirements, and operating conditions that collectively and uniquely influence the potential future performance of each individual unit.[240] Factors contributing to these differences include:

- variations between combustion turbine manufacturers and suppliers;
- variations in the vintage model combustion turbine employed;
- options for duel-firing natural gas, oil, or other gases in the combustion turbine;
- HRSG and steam turbine design differences;
- unit designs that integrate other, non-combustion-turbine related steam sources into the HRSG and steam turbine design;
- differences in equipment redundancy to support increased utilization;
- differences in the winterization of equipment to enable cold weather operations;
- differences in the condition of process equipment to support increased utilization;

EPA also ignores the fact that some existing NGCC units simply may not have been designed and constructed for the purpose of operating at higher capacity factors. For example, the language below from the air permits for two NGCC facilities in Arkansas states how these units are primarily intended to generate power during specific operating scenarios:

> The plant is designed to supply approximately 450 to 510 MW of power *during high electrical demand hours* of each day (usually between the hours of 7:00 a.m. and 11:00 p.m.) and ramp down to approximately 75 MW during off-peak hours. This daily load cycling results in reduced power production each day during hours when there is no demand for the power.[241]

and

> This unit is used primarily *for intermediate and peak* load conditions.[242]

[239] Combustion Turbine Standard TSD. EPA. 2014. Docket #: EPA-HQ-OAR-2013-0495-0082. pp. 1-4.
[240] EIA-860 and GHG Abatement Measures TSD.
[241] Arkansas Department of Environmental Quality Air Permit #l842-AOP-R5. March 15, 2010. p.5.
[242] Arkansas Department of Environmental Quality Air Permit #1165-AOP-R5. July 30, 2013. p.10.

A review of the historic data for these units is summarized below and indicates that both have operated at very low capacity factors – as they were designed and intended to operate - for various technical and economic reasons.[243] The full analysis provided in Appendix B.

| | Maximum Annual Capacity Factor (summer basis) 2003 - 2013 | Average Annual Capacity Factor (summer basis) 2003 - 2013 | Maximum Monthly Capacity Factor (summer basis) 2003 - 2013 |
|---|---|---|---|
| Oswald NGCC Unit regulated by ADEQ Permit #1842-AOP-R5 | 3.8% (occurred in 2011) | 1.8% | 46% (occurred in 2011) |
| Fitzhugh NGCC Plant regulated by ADEQ Permit #1165-AOP-R5 | 18.5% (occurred in 2006) | 6.6% | 44% (occurred in 2011) |

The historical operation of both units is *much less* than a 70% capacity factor, or even EPA's alternative 65% capacity factor. In fact, the highest *monthly* capacity ever recorded for these facilities is only a little better than half of EPA assumed rate. These two NGCC facilities have operated so little that if the total generation for each unit during the last 10 years (2004-2013) was added together and assumed to have occurred during one year, even those "hypothetical" annual generation totals are less than 70%. Under that scenario the annual capacity factors would be 61% (Oswald) and 68% (Fitzhugh). Clearly, EPA did not consider whether such units have the technical and economic feasibility to increase operations to obtain a 70% capacity factor during any one year, let alone to sustainably obtain that high capacity factor in the future. EPA merely assumes that this is the case by noting that:

> NGCCs are designed for, and are demonstrably capable of, reliable and efficient operation at much higher annual capacity factors, as shown in observed historical data for particular units and their design and engineering specifications.[244]

Ironically, in the proposed 111(b) standards for new sources, EPA did acknowledge that certain *existing and future NGCC units* may actually be designed for the purpose of operating at lower capacity factors by noting that:

> Small NGCC units...that are generally *designed for operation during peak demand* will usually supply less than one-third of their potential electric output to the grid.[245]

and

[243] Reviewed 2003-2013 Annual EIA860 and EIA923 reports available at www.eia.gov/electricity/data/eia860/ and www.eia.gov/electricity/data/eia923/index.html
[244] GHG Abatement Measures TSD. EPA. 2014. p. 3-14
[245] 79 Fed. Reg. 1445 (January 8, 2014). (emphasis added)

> A capacity factor exemption at 40%... would allow conventional combined cycle facilities *built with the intent to operate at relatively low capacity factors* as an alternative technology to simple cycle turbines because neither would be subject to the NSPS requirements.[246]

For those units that, perhaps, are not designed to readily increase utilization or that may not have historically operated at higher capacity factors, EPA references in the proposed CPP a 2011 paper to suggest that increased operation across the NGCC fleet is feasible. That paper notes that:

> "*...a four-pronged <u>approach for achieving higher availability and reliability</u> is outlined: (1) robust design utilizing the field data gathered during scheduled outages; (2) efficient scheduled outage management with emphasis on quality; (3) proactive intervention with remote monitoring technology and (4) improved design and upgrades for longer parts life*."[247]

EPA provides no evaluation to assess whether this "approach for achieving higher availability and reliability" has been or even could be implemented across the entire NGCC fleet. In fact, EPA fails to examine how any of the aforementioned unit-specific criteria may lessen the potential for existing units to increase operations in the future. EPA did recognize and account for some of these factors in the 111(b) proposal for new sources by proposing separate standards for two subcategories of combustion turbines based on the size of the unit. EPA explained these differences and the rationale for it subcategorization as follows:

> This subcategorization has a basis in differences in several types of equipment used in the differently sized units, which affect the efficiency of the units. Large-size combustion turbines use industrial frame type combustion turbines and may use multiple pressure or steam reheat turbines in the heat recovery steam generator (HRSG) portion of a combined cycle facility. Multiple pressure HRSGs employ two or three steam drums that produce steam at multiple pressures. The availability of multiple pressure steam allows the use of a more efficient multiple pressure steam turbine, compared to a single pressure steam turbine. A steam reheat turbine is used to improve the overall efficiency of the generation of electricity. In a steam reheat turbine, steam is withdrawn after the high pressure section of the turbine and returned to the boiler for additional heating. The superheated steam is then returned to the intermediate section of the turbine, where it is further expanded to create electricity. Although HRSGs with steam reheat turbines are more expensive and complex than HRSGs without them, steam reheat turbines offer significant reductions in $CO_2$ emission rates.
>
> Due to the higher efficiency of the simple cycle portion of an aeroderivative turbine based combined cycle facility, the HRSG portion would contribute relatively less to the

[246] Id.. 1459. (emphasis added)
[247] GHG Abatement Measures TSD. EPA. 2014. p. 3-6. (emphasis added)

> overall efficiency than a HRSG in a frame turbine based combined cycle facility. Therefore, adding a multiple steam pressure and/or a reheat steam turbine to the HRSG would be relatively more expensive to an aeroderivative turbine based combined cycle facility compared to a frame based combined cycle facility. Consequently, multiple pressure steam and reheat steam turbine HRSG are not widely available for aeroderivative turbine based combined cycle facilities. In addition, since aeroderivative turbine engines have faster start times and change load more quickly than frame turbines, aeroderivative turbine based combined cycle facilities are more likely to run at part load conditions and to potentially bypass the HRSG and run in simple cycle mode for short periods of time than industrial frame turbine based combined cycle facilities.
>
> Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) available on the market today are less efficient than the larger units (larger than 850 MMBtu/h). According to the data in the EPA's Clean Air Markets Division database, which contains information on 307 NGCC facilities, there is a 7 percent difference in average $CO_2$ emission rate between the small- and large-size units. This relative difference is consistent with what would be predicted when comparing the efficiency values reported in Gas Turbine World of small and large combined cycle designs.[248]

In summary, EPA has not demonstrated that it is feasible to establish a single capacity factor goal that can adequately account for and address unit-specific factors that affect the potential for increased utilization, whether that capacity factor is set at 65% or 70%. Aside from deferring to the lowest common denominator capacity factor that could potentially be achieved by an individual unit, it is not possible to determine a single goal that could be achieved by all units. Given the inherent differences that determine a unit's potential for increased utilization, EPA should abandon any attempt to apply a single capacity factor to all existing NGCC units.

### C. The criteria used by EPA to evaluate NGCC performance and to determine a redispatch capacity factor as the BSER is flawed

Any attempt by EPA to evaluate the potential level of NGCC redispatch for an individual unit or a broader group of similar units <u>must at least be grounded</u> in a firm understanding of the definition, purpose, and limitations of the unit operation and performance data considered. In describing its evaluation, EPA notes that "...the actual potential to realize emission reductions through this technology depends on the availability and capacity factors of the existing NGCC fleet."[249] By focusing its assessment on these two metrics, EPA not only narrows its review to

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[248] 79 Fed. Reg. 1486-1487 (January 8, 2014)
[249] Id. p. 3-5.

irrelevant (availability factors) and inaccurate (capacity factors) information, but also ignores other more significant factors that influence the utilization of a unit.

With respect to the availability factor, EPA states that "availability refers to the maximum amount of generation that could be expected from a given source," and that "[m]ore than 80% of the [existing NGCC] capacity...are able to achieve to achieve high availability factors."[250] EPA also notes that:

> The capability of NGCCs to operate at capacity factors of 70% and greater is indicated, in part, by statistics on the average availability factor of NGCCs, [which] in the U.S. generally exceeds 85%, and can exceed 90% for selected groups... Advanced NGCCs being built today have availability factors of over 95%.[251]

The availability factor is the percentage of time that a unit is available to provide energy to the grid, and is an indicator of the reliability of the unit and associated outage rates. In terms of assessing the potential for increased utilization of the NGCC fleet, the availability factor is of trivial value. The fact that a unit is available does not automatically imply that it can generate all of its demonstrated capacity. For example, a hydroelectric unit or wind turbine facility may be available, but water levels or wind conditions may be insufficient for those units to achieve their maximum potential output. The operation of every type of generation resource is affected by any number of factors that determine not only *if the unit is operated* when it is available, but also *how it is operated* when available. Therefore, the issue is not whether the unit has a high availability factor, as nearly all units and types of generation achieve that regularly. Rather, the issue is how the unit operates when it is available, which is a more complex evaluation given the number of dynamic technical, regulatory, economic, and market factors that must be weighted. Capacity factor is one metric to assess how often units operate when available. However, consideration of historic capacity factors in a vacuum is insufficient for evaluating the potential increased utilization that may be achievable by a unit.

[250] Id. pp. 3-6 to 3-7.
[251] GHG Abatement Measures TSD. EPA. 2014. p. 3-14.

The table below from NERC summarizes the availability factor and net capacity factor from 2009-2013 for various generation resources. All have high availability factors, but for various reasons have different capacity factors:

**2009-2013 Average Fleet Values[252]**

| | Weighted Equivalent Availability Factor | Net Capacity Factor |
|---|---|---|
| All Fossil Steam Units | 82% | 49% |
| Coal | 83% | 61% |
| Combined Cycle | 86% | 48% |
| Hydro | 84% | 41% |
| Oil Boilers | 80% | 9% |
| Gas Turbines | 90% | 2% |

EPA contends that part of the BSER for existing sources involves the redispatch of low-carbon emitting generation resources. Using this logic and the table above, then hypothetically existing combined cycle units, *as well as* oil steam boiler, simple cycle turbine, and hydroelectric units are all underutilized and should all be demonstrably redispatched at higher rates to offset higher emitting coal units. This overly simplistic scenario fails to consider the numerous aforementioned factors that influence how units are dispatched and the potential amount of increased utilization that may be achievable.

In addition, EPA's calculation of historic capacity factors based on the use of nameplate capacity is fundamentally inaccurate. Nameplate capacity is a nominal value used to represent and describe the gross rating or size of an electric *generator* – a specific piece of equipment. Nameplate capacity *does not* represent the maximum capacity of an electric *generating unit* – the entire power plant, including the electric generator. Because nameplate capacity is a descriptive value specific to the electric generator, it does not reflect the balance of plant equipment and systems, auxiliary load requirements, or site-specific conditions such as ambient temperature, humidity, or elevation that influence the actual net capability or rating of the unit. These factors are considered by the summer and winter net demonstrated capacity ratings reported for each unit. EPA alludes to these seasonal differences in the proposed rule by noting that:

> Net generating capacity is a function of weather/temperature conditions at the site, which varies throughout the year. While some units may model actual weather adjusted

[252] "2009-2013 Generating Unit Statistical Brochure – All Units Reporting." Aug. 14, 2014. NERC. www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

capacity by the hour/minute, these data are not reported for the fleet. Therefore, the EPA used the nameplate capacity reported for units.[253]

EPA suggestion that "weather adjusted capacity....data are not reported for the fleet" is also incorrect as both summer and winter net demonstrated capacities are reported annually to the Energy Information Agency ("EIA") and are summarized in the publically accessible EIA-860 report.[254] In fact, EPA's Regulatory Impact Analysis ("RIA') for the proposed 111(d) rule actually uses the net summer and net winter capacity data from the EIA-860 report to evaluate existing generation resources.[255] The RIA also summarizes an EPA analysis of coal-based generating units that includes an assessment of net summer capacity.[256] Data for this assessment is provided by the EPA National Electric Energy Data System ("NEEDS") database, which notes the following with respect to calculating capacity factors:

> The NEEDS unit capacity values implemented in EPA Base Case v.5.13 reflect net summer dependable capacity, to the extent possible. Table 4-4 summarizes the hierarchy of primary data sources used in compiling capacity data for NEEDS v.5.13; in other words, data sources are evaluated in this order, and capacity values are taken from a particular source only if the sources listed above it do not provide adequate data for the unit in question.[257]

| ***Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v.5.13 Sources Presented in Hierarchy*** |
|---|
| *2010 EIA 860 Summer Capacity* |
| *2011 EIA 860 Summer Capacity* |
| *2010 EIA 860 Winter Capacity* |
| *2011 EIA 860 Winter Capacity* |
| *2010 EIA 860 Nameplate Capacity* |
| *2011 EIA 860 Nameplate Capacity* |
| *Notes: Presented in hierarchical order that applies. If capacity is zero, unit is not included.* |

Seasonal net demonstrated capacity is also commonly used to calculate capacity factors by a variety of regulatory agencies, including the North American Electric Reliability Corporation ("NERC). The NERC instructions for reporting data to the generation availability data system ("GADS") provide the following equation for calculating capacity factor from net

[253] GHG Abatement Measures TSD. EPA. 2014. p. 3-6.
[254] Historic EIA-860 Reports. www.eia.gov/electricity/data/eia860/
[255] Regulatory Impact Analysis for the Propose Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. EPA. June 2014. EPA-452/R-14-002. p. 2-2.
[256] Id. p. 2-4.
[257] Chapter 4: Generating Resources. "Documentation for v.5.13". EPA. p. 4-4. www.epa.gov/powersectormodeling/BaseCasev513.html

generation data: Net Capacity Factor (%) = (Net Generation) / (Operating Hours x Net Maximum Capacity). The net capacity factor is the value that is then used to represent unit performance in NERC's annual Generating Unit Statistical Brochure.[258]

This widespread recognition and use of net seasonal capacity, including the rationale underlying EPA's own NEEDS database, renders EPA's use of nominal nameplate capacity for purposes of evaluating available underutilized NGCC capacity arbitrary and unreasonable. EPA's analysis incorrectly uses an "apples and oranges" comparison of actual net generation divided by nominal gross generation capacity to calculate an unrepresentative capacity factor that is biased low and is in no way representative of historic unit performance. This artificial capacity factor leads to an overestimate of the amount of NGCC capacity to be redispatched, an overly stringent state emission rate goal, as well as a false sense of flexibility that redispatch is a viable option for state plans and that redispatch will not significantly impact the reliability of the grid. Any use of historic capacity factor data to assess the potential for increased utilization of NGCC *must, first and foremost, be calculated correctly* and it must be evaluated in context with the broad scope of other factors that may influence the potential for greater operation.

### D. EPA provides no legitimate rationale for determining that a 70% capacity factor is achievable by the entire NGCC fleet

In the proposed rule, EPA rationalized the assumed 70% capacity factor redispatch rate as follows:

- In 2012, more than 10% of the NGCC plants operated at an annual capacity factor of 70% or greater.
- ...during the summer and winter peak electricity demand timeframes nationwide, more than 10% of NGCCs were operated at a capacity factor greater than 70%."
- ...19% of NGCCs achieved 70% capacity factor during the winter of 2011/2012 and 20% hit that level or higher during the summer.
- ...a notable number of existing NGCCs have demonstrated the ability to achieve a 70% capacity factor for extended periods of time....without adverse effects on the electric system.
- ...roughly 6% of units operated at a 75% capacity factor, or higher, in 2012...[and] 16% of units operated at 65%, or higher.

[258] Historic Generating Unit Statistical Brochures. www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

- While many units demonstrated the ability to deliver net generation that was more than 70% of their nameplate capacity, the EPA assumed 70% was a reasonable fleet-wide ceiling for each state.
- The demonstrated ability of the NGCC plants to consistently operate at levels greater than 70% of their nameplate capacity (e.g. this was the utilization of the ~90 percentile plant), the historic evidence supporting quick and significant redispatch to NGCC, and the cost-effectiveness of high NGCC utilization....all supported the notion of a NGCC fleet capacity factor of 70% as a reasonable ceiling in the EPA's BSER approach.[259]

The 70% capacity factor used by EPA is an arbitrary number selected based on the historic operation of a small percentage of NGCC units. While EPA rationalizes that the 70% value was "assumed [to be] reasonable" and that "more than 10%" of the existing units have operated at that level, such qualitative criteria offer nothing to credibly conclude that the 70% determination is technically, economically, or legally feasible. Indeed, EPA's process for selecting the 70% capacity factor gives no regard to important considerations such as the availability of adequate transmission capacity to allow increased NGCC utilization to offset the operations of other fossil fuel-fired facilities located in the same state; the availability of adequate and reliable sources of gas supply; existing unit conditions; outage scheduling; or the lack of regulatory authority or mechanisms necessary to establish and enforce such utilization requirements. EPA's own modeling of the proposed rule confirms that there are technical and/or economic constraints to running all NGCC units at a 70% capacity factor as the nationwide average capacity factors for NGCC units were 50 and 56% for the two Option 1 scenarios modeled by EPA.

**E. EPA has not fully evaluated the transmission and gas supply infrastructure issues that may significantly impact the feasibility and amount of potential redispatch**

EPA identifies natural gas supply and electric transmission as other influences that must be considered in evaluating the feasibility of increased utilization of the NGCC fleet, by noting

> EPA believes that the natural gas pipeline and electricity transmission networks can support aggregate operation of the NGCC fleet at up to a 70% capacity factor on average, either <u>as they currently exist or with modifications</u> that can be reasonably expected in the time frame for compliance with this rule.[260]

[259] GHG Abatement Measures TSD. EPA. 2014. pp 3-9 to 3-11.
[260] GHG Abatement Measures TSD. EPA. 2014. pp 3-14 to 3-15. (emphasis added)

Aside from qualitative statements and a high-level, incomplete, and generally irrelevant "analysis" of historic interstate natural gas flows, EPA fails to provide any credible or applicable review of the current state of the natural gas or electric transmission systems to determine areas that are sufficiently robust, that need "modifications" or that require new infrastructure to be developed. Instead of legitimately examining potential "reliability constraints" and the scope, cost, and timing of steps to address those issues, EPA chooses to address "compliance constraints" by stating that:

> constraints that occur at peak times are unlikely to be a barrier to achieving compliance with the rule, because these peak times are only a small percentage of the year and will constrain only a limited percentage of the state-wide NGCC fleet. These peak hours are the period when there are most likely to be constraints on the pipeline or electricity transmission networks; during other hours of the day, continued NGCC operation at equal, or higher levels, are technically feasible but may be limited by economic considerations... It is *reasonable to expect* that average *capacity factors could be extended* to higher levels at all hours *without experiencing technical feasibility barriers* from either pipeline supplies or electricity transmission."[261]

EPA's focus is on compliance with an annual limit, and not on maintaining reliability during "peak hours" when it is most critical to maintain natural gas supplies and the electric transmission system. The importance of maintaining the reliability of the gas supply and transmission systems should prompt a much more in-depth analysis, as opposed to one based on a cursory review of what is "reasonable to expect." EPA failed to fully evaluate existing natural gas supply and electric transmission constraints, contractual arrangements, or the timing and feasibility of necessary gas supply or transmission grid infrastructure improvements or expansion, each of which may limit the feasibility, reliability, and sustainability of units collectively operating at such high capacity factors. As discussed in the implementation section of comments below, timing considerations are also of significant concern with regards the time to plan, design, approve, and construct any necessary pipeline and transmission infrastructure.

1. EPA should thoroughly evaluate natural gas supply issues

EPA should thoroughly review the current state of the existing natural gas supply network and related contractual arrangements to determine if the system can readily support an

[261] Id. pp.3-15 to 3-16. (emphasis added)

increased utilization of the entire NGCC fleet and/or what infrastructure challenges must be addressed. Issues that EPA should investigate include the following:

- Natural gas pipeline transmission infrastructure is typically not built on speculation. FERC requires that pipelines demonstrate market need, most commonly shown through the execution of a sufficient level of long-term service contracts, before approving either expansions of existing infrastructure or development of new infrastructure. Pipeline and storage infrastructure capacity is sized to meet the contractual demand of firm customers, with little or no reserve capacity. Because the pipelines are sized to accommodate the needs of firm shippers, many pipelines are fully subscribed.

- Competition determines which natural gas pipeline will serve new load. There is no natural gas transmission pipeline equivalent to the electric industry's RTO's. The Interstate Natural Gas Association of America, the trade association that advocates regulatory and legislative positions of importance to the pipeline industry in North America, has stated, "the competitive model has worked well in the past and will continue to work well into the future". This competitive model may not, in fact, result in the most expedient, economic and holistic national expansion of the natural gas pipeline infrastructure.

- The availability of existing infrastructure and the construction of new infrastructure is locational. Economic access to sufficient, reliable delivery capacity will be location-specific. Each NGCC that has already been built may have enough pipeline infrastructure in place to meet its needs if it has made a Firm Transportation capacity commitment for its full requirements. If it has not, then additional pipeline infrastructure may be needed to support a 70% capacity factor. The siting of new gas-fired electric generation will need to balance the cost and timing of both natural gas pipeline and electric transmission system expansion.

- Incremental costs for Firm Transportation and balancing services unique to electric generation loads may not result in the economic dispatch of NGCC's up to 70% capacity factor. However, if the units are dispatched at a 70% or greater capacity factor, the reservation charges associated with Firm Transportation Service (FTS) could be more efficiently utilized. Currently, the RTO model does not allow the cost of FTS to be included in the bid/offer. Consequently, it is estimated that less than 50% of the nation's gas-fired electric generation is served by FTS as the electric generators have no ability to recover this cost from the RTO.

- EPA's proposed timeline may not be sufficient to increase existing NGCC plant capacity factors to as much as 70%. If new infrastructure is necessary, it could take up to three years from Service Agreement execution until initial natural gas deliveries. Regulatory and environmental approvals, engineering design, easement acquisition and construction have discrete timeframes that allow only minimal flexibility by location. Furthermore, electric generating utilities will not be able to make the commitment for Firm Transportation service until the proposed rule is finalized and the state plan is approved. If additional NGCC capacity is needed the utility will also need Certificate of Public Convenience and Necessity approval from the governing state public service commission before it will be in a position to subscribe for Firm Transportation.

- Increased demand for pipeline infrastructure across the country to comply with the final requirements could increase competition for construction labor and materials. Significant expansion is already occurring throughout the northeast and the demand for limited resources is being stretched. Additional pressure on these resources could increase costs and delay completion of projects by the required to support compliance with the final rule.

Evaluating these types of issues in more detail would offer a more credible assessment of potential natural gas supply concerns than the following qualitative conclusions that EPA makes in the proposed rule:

- natural gas pipeline *capacity is regularly added* in response to increased gas demand and supply;
- Upgrades to pipeline...infrastructure...will *generally* be less expensive than upgrades of that infrastructure potentially needed for siting of new capacity;
- significant[ly] higher levels of end-use *energy efficiency....will reduce the load* on the... natural gas pipeline infrastructure... [which will] decrease need for new generating units and reduced peak demands; and
- Based on a review of interstate natural gas pipeline flows, increased use of natural gas in existing facilities can be largely met with expansions to existing pipeline facilities and corridors.[262]

2. EPA should thoroughly evaluate electric transmission issues

EPA failed to identify or fully evaluate potential constraints within or impacts to the electric transmission system that may limit the feasibility, reliability, and sustainability of NGCC units collectively operating at higher capacity factors. Instead, EPA dedicates only two paragraphs within their 27 page review of building block two, along with a couple of minor passing references, to the process of completing potential transmission system upgrades. These qualitative references include:

- The electric transmission system has also been expanded in the past few years, and continued investment is expected.
- Upgrades to transmission infrastructure...will generally be less expensive than upgrades of that infrastructure potentially needed for siting of new capacity
- significant higher levels of end-use energy efficiency....will reduce the load on the electricity transmission...[which will] decrease need for new generating units and reduce peak demands[263]

[262] Id. pp. 3-16 to 3-18 (emphasis added)

EPA also references EIA and EEI reports of "planned" transmission projects, but offers no context as to whether these "planned' projects will address any specific issues related to the increased dispatch of NGCC units.[264] Detailed comments on the significant transmission and reliability concerns associated with the proposed rule are provided in a separate section. EPA must perform a more thorough review of transmission issues to determine the feasibility of building block two and the entire proposal.

**F. EPA failed to evaluate existing air permit conditions that may significantly impact the feasibility and amount of potential redispatch**

A variety of air permit requirements are in place that provide operational flexibility or that restrict operations, which may significantly impact the amount of potential redispatch that may be available for certain units. Examples include NGCC units that are permitted:[265]

- to combust fuel oil and natural gas;
- to co-fire other fuels with natural gas (oil, landfill gas, coal gas, etc.);
- with conditions that limit natural gas use, which effectively limits the potential capacity factor that is achievable;
- to operate in simple-cycle or combined cycle mode; and
- to operate the steam turbine with steam that is comingled from sources that are separate from the HRSG.

Some permits actually envision scenarios when natural gas supplies would not be available to operate the unit and allow the generator the flexibility to use oil or other fuels as an alternative. For example, consider the following permit condition from an NGCC facility in Rhode Island:

> Natural gas shall be deemed unavailable in cases of interruption in supply or transportation resulting from equipment failure, regulatory actions or interruption of supply outside of the control of the permittee.
>
> Natural gas shall be deemed unavailable if:
>
> (1) ISO-New England has declared a "Cold Weather Event" pursuant to Market Rule 1, Appendix H, "Operations During Cold Weather Conditions". The permittee may utilize fuel oil for each Operating Day (12AM-12PM) that this condition exists; or,

[263] Id. pp.3-16 to 3-20.
[264] Id. p. 3-20.
[265] See Appendix D.

> (2) ISO-New England has declared a "Cold Weather Watch" or a "Cold Weather Warning" pursuant to Market Rule 1, Appendix H, "Operations During Cold Weather Conditions" and either ISO-New England has forecast ISO New England Operating Procedure No. 4 conditions in its Morning Report or as revised/updated during the Operating Day, or has taken any action under ISO New England Operating Procedure No. 4. The permittee may utilize fuel oil for the 24-hour period between issuance of the Morning Reports (9AM Day 1 to 9AM Day 2) that this condition exists;
>
> Natural gas shall not be deemed unavailable on the basis of any increase in the cost of supply or transportation or allocation of available natural gas to other facilities within the control of the permittee.
>
> If natural gas is unavailable, the permittee may utilize fuel oil, with sulfur content of 0.05 percent or less by weight, as replacement fuel.[266]

Although these types of issues should have been considered, EPA made no attempt to evaluate existing permit limits or determine how existing requirements may limit the feasibility of NGCC units to achieve increased utilization rates.

## G. EPA should exclude combined heat and power ("CHP") facilities from the building block two calculations for NGCC units

### 1. CHP units should be considered separately from NGCC units

Major differences exist between the purpose, design, fuel flexibility, and operating philosophy of combined heat and power facilities and NGCC units such that CHP facilities that meet the definition of a 111(d) affected source should considered separately in the building block calculations. EPA acknowledges and discusses these distinguishing characteristics thorough a website and support documents associated the "EPA Combined Heat and Power Partnership," which the agency describes as:

> a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects[267]

In fact, EPA developed a "CHP Project Development Handbook" to support the development of new projects, which notes the following with respect to feasibility:

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[266] Manchester Street NGCC Plant Air Permit. RI-22-07. Rhode Island Department of Environmental Management. July 31, 2009.

[267] www.epa.gov/chp/

> Whether CHP can be economically beneficial at any particular site depends on a host of site-specific characteristics such as the energy consumption profiles of the facility, the relative prices of fuel and retail electricity, and the costs of installing and maintaining the CHP equipment.[268]

Further, to highlight the differences in how CHP facilities operate, consider the permit condition for one CHP facility in Connecticut, which discusses significantly different options for operation the unit as follows:

> General Electric turbine (EU1-Permit No. 213-0029) and two Nebraska boilers (EU2 – Permit No. 213-0031 and EU3 – Permit No. 213-0032) burn natural gas and No. 2 fuel oil. The turbine and the boilers can be operated by themselves or under the following combinations: turbine and the equivalent of one boiler, two boilers without the turbine.[269]

2. EPA should evaluate whether individual CHP units are affected sources subject to the 111(d) guidelines

In addition to considering CHP facilities apart from NGCC units, EPA must also thoroughly assess whether the CHP units identified in the proposed rule even meet the definition of an affected source that is subject to the 111(d) guidelines. Several examples have been identified in the building block two calculations of certain CHP units that clearly do not meet the definition of "affected sources" subject to the proposed rule. EPA's criteria for determining "affected sources" in the proposed rule is summarized as follows:

> The EPA is proposing that, for the emission guidelines, an <u>affected EGU</u> is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an "existing source" for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 1430; January 8, 2014).[270]

The proposed 111(b) standards for new sources revised the "applicability criteria" in several ways for determining whether a facility is an "affected source." Most relevant to combined heat and power facilities are revisions to (1) the averaging period used to assess applicability with the net electric output criterion, and (2) the exclusion of electric output consumed by the host industrial facility.

Specifically, revisions in the averaging period are related to the applicability criteria that "affected sources" are those EGUs that are "*constructed for the purpose of supplying more than*

[268] "CHP Project Development Handbook." p. 17. www.epa.gov/chp/documents/chp_handbook.pdf
[269] Algonquin Power Windsor Locks, LLC Title V Permit #213-0069-TV. Connecticut DEP. Oct. 31. 2012. p.7.
[270] 79 Fed. Reg. 34854. June 18, 2014. (emphasis added)

*219,000 MWh...net-electrical output to the grid*." To evaluate this requirement EPA notes that "We are also proposing to *revise the averaging period* for electric sales from an annual basis to a *three-year* rolling average for stationary combustion turbines."[271] With respect to the definition of net electric output, EPA proposed adding the clause "*of the thermal host facility or facilities*."[272] In describing the rationale for that revision, EPA notes:

> [O]ne potential issue that we have identified is inequitable applicability of third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. The current definition of net electric output...is 'the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis. Owners/operators of a CHP facility under common ownership as an adjacent facility using the thermal output from the CHP (i.e. the thermal host) can subtract out power purchased by the adjacent facility on an annual basis when determining applicability. However, third-party CHP developers would not be able to benefit from the 'minus purchased power on a calendar basis' provision in the definition of net electric output when determining applicability since the CHP facility and the thermal host(s) are not under common ownership. We are therefore proposing to....make applicability consistent for both facility-owned CHP and third-party owned CHP. [273]

The applicable definitions in the 111(b) proposals for new sources and for modified and reconstructed sources incorporate these revisions.[274] However, the 111(d) proposal selectively includes only the language related to using a three-year average. A comparison of the definitions in each proposal is provided below:

| Proposed 111(b) for New Sources<br>79 Federal Register 1509-1510<br>(January 8, 2014) | Proposed 111(d) for Existing Sources<br>79 Federal Register 34956 – 34957<br>(June 18, 2014) |
|---|---|
| "Net-electric output means...<br>(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a <u>3 calendar year rolling average basis</u>, the gross electric sales to the utility power distribution system <u>minus purchased power of the thermal host facility or facilities on a three calendar year rolling average basis.</u>" | "Net energy output means...<br>(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a <u>rolling 3 year basis</u>, the net electric or mechanical output from the affected facility divided by 0.95, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application)" |

[271] 79 Fed. Reg. 1446. January 8, 2014. (emphasis added)
[272] Id. 1460. Note the "emphasis added" statement comes directly from the proposed rule.
[273] Id.
[274] See 79 Fed. Reg. 34979 pertaining to the proposed 111(b) standards for modified and reconstructed sources.

The proposed 111(d) guidelines *fail to mention* EPA's concern of the "*inequitable applicability of third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility*." Further, even though EPA included the "rolling 3 year basis" in the definition, *nothing has been found in the docket* to suggest that EPA actually performed an analysis of 3 year averages to determine the applicability of individual CHP facilities. Multiple CHP facilities have been identified that appear to have been erroneously included in the building block two calculations that otherwise would have been excluded had EPA properly considered all of the definitional revisions proposed in the 111(b) rulemakings. For example, EPA appears to have incorrectly included the Portside Energy CHP unit as an existing NGCC facility when performing the building block two calculations for the state of Indiana. A review of the facility in context with how it is designed, where its located, and how its electric and thermal output is employed strongly suggests that the facility provides nearly all of its electricity to the "host facility" (not to a "utility distribution system"), and thus is not an affected source. A recent article about the facility noted that:

> Portside Energy's plant on the grounds of the U.S. Steel Midwest mill.. provides most of the steel mill's electricity needs and all of its steam and hot water needs [275]

A sufficient number of similar examples were identified through a cursory review of other cogeneration facilities to suggest that the inclusion of CHP units within the building block two calculations for NGCC units is fundamentally flawed. The end result is (1) that the 111(d) proposal is illegally applicable to a broader suite of sources than those that are subject to 111(b) new source standards;[276] (2) EPA's building block two calculations inaccurately include co-generation sources that are <u>not</u> affected sources subject to the proposed requirements; and (3) the corresponding state goal calculations, reliability assessments, and cost-benefit analysis are derived from inaccurate data.

If EPA intended to identify affected sources under 111(d) "*that in all other respects would meet the applicability criteria for coverage under the proposed* [111(b)] *standards*," then EPA must *adopt and apply* that criteria in determining the applicability of existing co-generation units to the proposed rule. Further, co-generation units are principally designed and operated to supply heat and power to a specific industrial or commercial process. EPA must evaluate

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[275] www.midwestenergynews.com/2014/06/20/combined-heat-and-power-is-a-boon-for-midwest-steel-mills/
[276] See the supporting legal discussion in Section IV.F.

whether co-generation units could even be redispatched at higher capacity factors if such increased utilization would significantly impact or jeopardize the ability of units to achieve their primary objective of providing heat and power to a host process.

3. EPA incorrectly applies the electric output associated with useful thermal output from CHP units in the building block two calculations

Co-generation units are capable of providing both electric energy output and useful thermal output ("UTO"). For combined heat and power facilities subject to the proposed rule, EPA calculates $CO_2$ emissions and energy output (in MWh) associated with the useful thermal output that is not used for electricity production. EPA then adds only the UTO related energy output to the electric output to calculate a revised baseline NGCC emission rate for the facility. The UTO related $CO_2$ emissions *are not* used to calculate the revised baseline NGCC emission rate, but instead are added into the "Other Emissions" component of the building block two methodology. The affect is significant as it creates an artificially low $CO_2$ emission rate for the facility that leads to an inaccurate baseline NGCC emission rate that is biased low and that has not been adequately demonstrated. This results in overly stringent state emission rate goal.

This concern is illustrated using the EPA goal calculations for Arkansas where the agency identifies seven NGCC facilities in the state, one of which is a CHP unit (Pine Bluff) where energy output and $CO_2$ emissions associated with useful thermal output were calculated. The impact of EPA's methodology for considering UTO energy output is significant as it reduces Pine Bluff's emission rate by 47% from 1,132 lb./MWh to 602 lb./MWh – a rate that is not remotely close to have been demonstrated by any NGCC unit. In turn, the average NGCC $CO_2$ emission rate for Arkansas is reduced by 8% from 896 lb./MWh to 827 lb./MWh, as shown in the table below. *None* of the other six NGCC units had annual $CO_2$ emission rates less than or equal to 827 lb./MW, and *none* would ever be expected to achieve a rate of 602 lb./MWh. The absurdity of the 602 lb./MWh value becomes apparent after review of any number of EPA databases, studies, and reports that have evaluated NGCC $CO_2$ emission rates,[277] which indicates that even the most optimistic of $CO_2$ emission rates are much higher (hundreds of lb./MWh higher) than the 602 lb./MWh rate calculated for Pine Bluff.

[277] For example, EPA RBLC database (http://cfpub.epa.gov/rblc/); EPA Region 6 GHG PSD permit database (http://yosemite.epa.gov/r6/Apermit.nsf/AirP#A); or EPA Combustion Turbine TSD (www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0082)

**EPA Building Block Two Calculations for Arkansas NGCC Facilities**[278]

| | 2012 CO2 (tons) | 2012 Net Generation (MWh) | 2012 CO2 Rate lb/MWh net | Useful Thermal Output (MWh) | Useful Thermal Output (CO2 tons) | 2012 Net Energy Output (Net Gen + UTO MWh) | 2012 CO2 Rate lb/MWh - net energy output | CO2 Emission Rate % Reduction lb/MWh (net gen) vs. lb/MWh (net gen + UTO) |
|---|---|---|---|---|---|---|---|---|
| Data Source | EPA | EPA | Calculated | EPA | EPA | EPA | Calcuated | Calculated |
| Dell Power Station | 317,306 | 687,809 | 923 | --- | --- | 687,809 | 923 | --- |
| Harry L. Oswald | 180,415 | 356,365 | 1,013 | --- | --- | 356,365 | 1,013 | --- |
| Hot Spring Gen. Facility | 226,155 | 513,634 | 881 | --- | --- | 513,634 | 881 | --- |
| Magnet Cove | 1,082,150 | 2,578,521 | 839 | --- | --- | 2,578,521 | 839 | --- |
| Pine Bluff Energy Center | 842,709 | 1,489,105 | 1,132 | 1,310,917 | 394,540 | 2,800,022 | 602 | -47% |
| Thomas Fitzhugh | 64,818 | 114,459 | 1,133 | --- | --- | 114,459 | 1,133 | --- |
| Union Power Partners LP | 4,302,025 | 9,911,292 | 868 | --- | --- | 9,911,292 | 868 | --- |
| ARKANSAS NGCC Fleet 2012 Average CO2 Rate | 7,015,577 | 15,651,185 | 896 | | | 16,962,102 | 827 | -8% |

[278] EPA data from "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602.

In addition to the Pine Bluff facility, the $CO_2$ emission rates for 82 other NGCC units were calculated using the UTO-related energy output. A summary of the UTO impact to the emission rates calculated for all of these facilities is provided in Appendix B. It is noteworthy, that eight facilities had $CO_2$ emission rates that were even lower than the absurd value EPA calculated for Pine Bluff. The units are summarized below:[279]

| State | Plant | 2012 CO2 Rate lb./MWh net generation | 2012 CO2 Rate lb./MWh net energy output | CO2 Emission Rate % Reduction lb./MWh (net gen) vs. lb./MWh (net gen + UTO) |
|---|---|---|---|---|
| PA | Grays Ferry Cogeneration | 1,451 | 348 | -76% |
| TX | Gregory Power Facility | 1,301 | 485 | -63% |
| CT | Algonquin Windsor Locks | 673 | 532 | -21% |
| TX | Channel Energy Center LLC | 937 | 543 | -42% |
| MI | Dearborn Industrial Generation | 1,059 | 578 | -45% |
| TX | Channelview Cogeneration Plant | 1,193 | 587 | -51% |
| CA | Greenleaf 1 Power Plant | 808 | 593 | -27% |
| LA | Louisiana 1 | 1,447 | 599 | -59% |
| AR | Pine Bluff Energy Center | 1,132 | 602 | -47% |

[279] Id.

It also worth noting while a single co-generation facility reduced the overall state NGCC fleet $CO_2$ rate in Arkansas by 8%, other states have multiple co-generation units that may have much more significant impact. For example, EPA identified 14 co-generation facilities in Texas whose $CO_2$ emission decreased on average by 34% with the application of the UTO energy output. These results are summarized below:[280]

| State | Plant | 2012 CO2 Rate lb./MWh net generation | 2012 CO2 Rate lb./MWh net energy output | CO2 Emission Rate % Reduction lb./MWh (net gen) vs. lb./MWh (net gen + UTO) |
|---|---|---|---|---|
| TX | Gregory Power Facility | 1,301 | 485 | -63% |
| TX | Channel Energy Center LLC | 937 | 543 | -42% |
| TX | Channelview Cogeneration | 1,193 | 587 | -51% |
| TX | Clear Lake Cogeneration Ltd | 1,222 | 623 | -49% |
| TX | Sabine Cogen | 1,534 | 633 | -59% |
| TX | Deer Park Energy Center | 1,193 | 643 | -46% |
| TX | Pasadena Cogeneration | 830 | 705 | -15% |
| TX | Texas City Power Plant | 1,500 | 751 | -50% |
| TX | Eastman Cogeneration Facility | 1,176 | 754 | -36% |
| TX | Baytown Energy Center | 889 | 850 | -4% |
| TX | C R Wing Cogen Plant | 1,125 | 928 | -18% |
| TX | Oyster Creek Unit VIII | 1,336 | 1,127 | -16% |
| TX | Optim Energy Altura Cogen | 1,413 | 1,327 | -6% |
| TX | SRW Cogen LP | 1,728 | 1,454 | -16% |
| | | Average Reduction = | | -34% |

The building block two calculations for 24 states included the addition of UTO related energy output when determining the baseline NGCC $CO_2$ emission rate. The impact of the added UTO energy output can be significant as is most evident in the reduction in the baseline NGCC $CO_2$ emission rates for Louisiana (-21%), Michigan (-19%), Washington (-17%), and Texas (-14%).[281]

[280] Id.
[281] Id.

### H. EPA has significantly overestimated the amount of NGCC capacity available for redispatch due to egregious methodological issues and data quality errors

Close examination of EPA NGCC redispatch calculations identified numerous fundamental calculation errors and data quality issues that result in the amount of potential redispatch to be substantially overstated. These flaws include (1) incorrect data inputs; (2) inappropriate use of nominal nameplate capacity instead of the actual net demonstrated capacity; (3) incorrect inclusion of units that do not meet the definition of an "affected source" subject to the proposed rule; (4) incorrect inclusion of NGCC units that were never constructed; along with (5) incorrect and inconsistent assumptions on units that were commissioned in 2012 or later. Each of these issues and other concerns are discussed in detail below. EPA must correct these errors and determine how these corrections affect the state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses reflected in the proposed rule. Given the scope of issues to be resolved, EPA must withdraw the current proposal, correct the errors within building block two, and publish a new proposed rule for public comment.

1. EPA incorrectly uses "nameplate" capacity in the block 2 calculations

As detailed in the comments above, nameplate capacity is a nominal value used to represent and describe the gross rating or size of an electric *generator* – a specific piece of equipment. Nameplate capacity *does not* represent the maximum capacity of an electric *generating unit* – the entire power plant, including the electric generator. Because nameplate capacity is a descriptive value specific to the electric generator, it does not reflect the balance of plant equipment and systems, auxiliary load requirements, or site-specific conditions such as ambient temperature, humidity, or elevation, all of which can influence the actual net capability or rating of the unit. Use of the descriptive nameplate value results in an artificial capacity factor that in turn overestimates of the amount of NGCC capacity to be redispatched, produces a more stringent state emission rate goal, and exaggerates the viability of redispatch as an option for state plans. The table below compares differences in the demonstrated net capacity and the nominal nameplate descriptor for Ohio, which is typical for each state where NGCC capacity was identified by EPA.[282]

[282] Nameplate and Summer Capacity Data per the 2012 EIA-860 Report. www.eia.gov/electricity/data/eia860/

| Ohio NGGC Plant | Nameplate Capacity (MW) | Summer Capacity (MW) |
|---|---|---|
| Dresden | 678.3 | 540.0 |
| Fremont | 739.5 | 667.3 |
| Hanging Rock | 1,288.2 | 1,252.0 |
| Washington | 714.9 | 626.0 |
| Waterford | 921.6 | 810.0 |
| Ohio Total: | 4,342.5 | 3,895.3 |

EPA actually compares the nameplate and summer capacities for each existing electric generation source in the Regulatory Impact Analysis for the proposed rule. On a national basis for units combusting natural gas the summer capacity is 13% less than the nameplate capacity (422,364 MW vs. 485,957 MW).[283] EPA must resolve this significant methodological error and use the net demonstrated seasonal capacity values for each unit, not the nominal nameplate descriptor.

2. EPA incorrectly includes simple-cycle and gas boiler units in their calculation of "existing" NGCC capacity

EPA designed building block two to apply to existing NGCC units that are within the regulated source categories. However, in the goal calculations for some states, EPA incorrectly included natural gas simple-cycle and gas steam units as part of the existing NGCC capacity. EPA must revise its state goal calculations to ensure that natural gas simple-cycle and steam boiler units are not included as part of the existing NGCC capacity. Examples of this issue include the following:

| State | Plant | Unit | Identified by EPA as an existing NGCC unit?[284] | Actual Unit Type |
|---|---|---|---|---|
| Louisiana | Louisiana 1 | 1A | yes | natural gas steam boiler |
| Louisiana | Louisiana 1 | 2A | yes | natural gas steam boiler |
| Louisiana | Louisiana 1 | 3A | yes | natural gas steam boiler[285] |
| Louisiana | Perryville Power Station | 2-CT | yes | simple cycle CT[286] |

[283] RIA for the Propose Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. EPA. June 2014. EPA-452/R-14-002. p. 2-2.
[284] "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602
[285] Louisiana Department of Environmental Quality Air Permit #PER20130004. December 16, 2013.
[286] Louisiana Department of Environmental Quality Air Permit #PER20120003. September 14, 2012.

3. Building block two incorrectly and inconsistently includes NGCC units that were constructed after 2011

EPA defines two categories of applicable 111(d) NGCC units in the building block two calculations: "existing" units and "under construction" units. EPA assumes that the "existing" category of units were available to operate all of 2012 in order to calculate a baseline generation rate for these units that is then redispatched to a 70% capacity factor. For the "under construction" category of units, EPA assumes that those units were constructed to meet a specific demand requirement that is equivalent to a 55% capacity factor from those units. EPA then assumes that these "under construction" units are available for redispatch at a 15% capacity factor (70% - 55% = 15%). The fatal flaw of EPA's approach is its inconsistent, incomplete, and inaccurate consideration of all NGCC units that were commissioned during and after 2012 in terms of if and how these units were classified into the "existing" or "under construction" category.

Clearly, EPA does not have an accurate grasp of the status of these "new" units as numerous errors have been identified related to the scope of units considered (or not considered), EPA's assumptions regarding the status of these projects, and EPA's methodology for considering these units within the block two calculations. A detailed discussion of these issues is provided in the comments below. EPA must correct these issues, which significantly diminish the capacity to be included within building block two. For accuracy and completeness, EPA should first review the scope of all NGCC units commissioned or to be commissioned after December 31, 2011 and second treat all of these units equally as "under construction" in the building block 2 calculations.

a. In the calculation of existing NGCC capacity available in 2012, EPA incorrectly included units that had/have not yet been commissioned

In the goal calculations for certain states, EPA incorrectly included certain NGCC projects that were not commissioned until after 2012 as part of the "existing" NGCC units that were redispatched up to a 70% capacity factor. In fact, one example was identified for a facility that has not received its air permit or commenced construction, and as such would not be an affected source subject to the proposed section 111(d) guidelines. EPA must revise these calculations to exclude such units and to ensure that the existing NGCC units considered have actually been constructed. Examples include the following:

| State | Plant | Identified by EPA as an existing NGCC unit?[287] | Status |
|---|---|---|---|
| AK | Southcentral Power Plant | yes | commissioned – Jan. 2013[288] |
| CA | El Segundo Energy Center | yes | commissioned – Sep. 2013[289] |
| CA | Russell City Energy Center | yes | commissioned – Aug. 2013[290] |
| FL | Cape Canaveral | yes | commissioned – April 2014[291] |
| UT | Lake Side 2 | yes | commissioned in 2014[292] |
| LA | Washington Parish Energy Center | yes | not commenced construction[293]<br>air permit has not been issued[294] |

b. EPA has incorrectly calculated the post-2012 "under construction" NGCC capacity for *all states* where the agency determined it applied

In terms of the NGCC capacity that EPA classified as "under construction" in the building block two calculations, EPA assumed that these facilities are being constructed to meet a specific demand that is equivalent to a 55% capacity factor.[295] Based on this assumption, EPA

[287] "Goal Computation Technical Support Document – Appendix 7." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602
[288] www.mlandp.com/FACT%20SHEET_SouthcentralPowerProject_2013.pdf
[289] www.dailybreeze.com/government-and-politics/20130912/new-energy-efficient-power-plant-unveiled-in-el-segundo and http://elsegundorepowering.com/
[290] www.calpine.com/power/plant.asp?plant=261
[291] www.fpl.com/news/2014/041014.shtml
[292] www.pacificorp.com/.../pacificorp/doc/Energy_Sources/EnergyGeneration_FactSheets/RMP_GFS_Lake_Side.pdf
[293] http://theadvocate.com/home/8941063-125/calpine-sells-st-gabriel-power. April 22, 2014.
[294] http://edms.deq.louisiana.gov/app/doc/queryresults.aspx
[295] EPA's assumption that units under construction were anticipated to reach a 55% capacity factor is inherently inconsistent with the premise of this entire building block. If a 55% capacity factor is sufficient to incent construction of a new unit, a 70% capacity factor would seem to represent an extraordinarily high utilization rate.

calculated that 15% of this "under construction" capacity would be redispatched under building block two.

EPA determined that nine states had NGCC units that were "under construction" – a determination that is *incorrect for each of the nine states*. For five of these states, the units determined to be "under construction" by EPA represent fictitious "potential" units identified within EPA's NEEDS database and Integrated Planning Model. NEEDS describes potential units as follows:

> "Potential" units refer to new generating options used in IPM for capacity expansion projections of the electric industry... whereas *potential units are endogenous to the model* in the sense that the model determines the location and size of all the potential units that end up in the final solution for a specific model run.[296]

These "potential" units are nothing more that phantom units that do not represent real projects that have been proposed, designed, permitted, or constructed. To the extent that these "potential" projects come to fruition, they would be subject to the new source standards under 111(b), not the existing source 111(d) guidelines. As such, these "potential" units should not be considered in building block two.

For the remaining four states, the inaccurate inclusion of these units as "under construction" capacity is largely a result of the EPA incorrectly assessing the actual status of these units. For example, the one "under construction" facility identified by EPA for Ohio is the Dresden Plant that was actually commissioned in 2012. The one "under construction" facility in Kentucky is the Cane Run project, which has yet to receive an air permit and has not yet commenced construction.[297]

For Virginia, the data source used by EPA to determine that 1,928 MW of NGCC capacity is "under construction" has not been determined. EPA employed the NEEDS database to determine the under construction capacity in other states, but NEEDS lists only 570 MW of capacity related to a plant that has yet to receive an air permit or commenced construction.[298] A separate review of the 2012 EIA860 report identified 2,801 MW of "proposed" NGCC capacity in Virginia, but only 1,472 MW of that capacity represents units that are known to have

[296] Chapter 4: Generating Resources. "Documentation for v.5.13". EPA. p. 4-1. www.epa.gov/powersectormodeling/BaseCasev513.html
[297] 2013 EIA-860 Report. www.eia.gov/electricity/data/eia860/
[298] www.deq.state.va.us

commenced construction.[299] Finally, EPA identified 220 MW of "under construction" capacity in Wyoming, which is associated with the Cheyenne Prairie Generating Station. This project includes both a combined cycle unit and a separate simple cycle unit that together have a nameplate capacity of 220 MW. However, only 100 MW of that capacity is associated with the combined cycle process.[300]

Not only has EPA mischaracterized the under construction NGCC capacity for nine states, but the agency has not recognized other proposed NGCC projects that may fall into the under construction category. For example, a review of the spreadsheet tab marked "proposed" in the EIA860 report that has been referenced by EPA quickly identifies many potential NGCC projects that were simply ignored by EPA in building block two. Potential NGCC projects have been identified for over 20 states, which may meet the definition of "under construction" as currently defined in building block two.[301]

Further, in determining the $CO_2$ emissions associated with the redispatch of "under construction" capacity, EPA used either the average emission rate for existing NGCC units in the state, or a national average if the state did not have any existing units.[302] Based on the significant flaws in how the state average NGCC emission rates were calculated, EPA's approach for determining the future emissions from under construction units is inaccurate and inequitable. To highlight these differences, consider the emission rates that were assumed for the NGCC facilities that EPA alleges are "under construction," even though most of these examples are not actual projects.

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[299] *See* www.eia.gov/electricity/data/eia860/ and www.deq.state.va.us
[300] www.blackhillscorp.com/cpgs
[301] EIA-860 Report. www.eia.gov/electricity/data/eia860/
[302] "Goal Computation Technical Support Document." June 2014. EPA. p. 13.

| State Identified by EPA as having "under construction" NGCC Capacity | Baseline State NGCC $CO_2$ Emission Rate Used to Calculate Future Emissions from "Under Construction" NGCC units[303] |
|---|---|
| California | 867 |
| Colorado | 928 |
| Florida | 864 |
| Kentucky | 907 |
| Mississippi | 848 |
| North Carolina | 851 |
| Ohio | 963 |
| Virginia | 903 |
| Wyoming | 907 |

EPA must correct these errors in both the scope of "under construction" units considered and the assumptions for consistently estimating emissions from these units.

c. EPA fails to consider certain existing NGCC units that were commissioned during or after 2012

A number of NGCC projects were identified that could be considered existing 111(d) facilities, but were ignored by EPA in the building block two calculations. These are units that commenced construction after 2012, but before January 8, 2014 – the effective date that the 111(b) standards for new sources were re-proposed by EPA. Examples of such facilities include the following:

| State | Plant | Summer Capacity (MW)[304] | Considered by EPA in building block 2?[305] | Commenced Construction Date |
|---|---|---|---|---|
| TX | Panda Sherman Power Station | 717 | no | Nov 2012[306] |
| TX | Panda Temple Power Station | 717 | no | Sep 2012[307] |
| TX | Thomas C Ferguson | 510 | no | Apr 2012[308] |

303 "Goal Computation Technical Support Document." June 2014. EPA
304 "Proposed Units." EIA-860. 2012. www.eia.gov/electricity/data/eia860/
305 "Goal Computation Technical Support Document." EPA. June 2014.
306 www.pandafunds.com/broadcast/news-releases/sherman-groundbreaking/ &www.kten.com/story/25042685/construction-at-panda-sherman-power-nears-completion
307 www.bechtel.com/2012-09-06.html
308 www.turbomachinerymag.com/blog/content/san-marcos-partner-lcra-new-540-mw-ferguson-power-plant-project

d. EPA incorrectly accounts for NGCC units commissioned during 2012 in their calculation of potential redispatch amounts

EPA overstates the amount of redispatch available from NGCC units commissioned in 2012 because it does not weigh the commissioning date into its calculation. In other words, when calculating redispatch, EPA assumes that all of these units were available to operate throughout 2012 even though some of these units were not commissioned until later in the year. This faulty assumption means that these new units are calculated to have an artificially low capacity factor, which produces an artificially high amount of NGCC redispatch. The end result is a state emission rate goal that is biased low. For example, two of the five existing NGCC units in Ohio were commissioned in 2012.[309] The table below compares baseline capacity factors for these two facilities if calculated based on their in-service date versus EPA's assumption that they were available for the entire year.[310]

| | | | | | | EPA Method | | |
|---|---|---|---|---|---|---|---|---|
| | In Service Date | 2012 Net Gen (MWh) | Potential Operation Hours | Summer Net Capacity (MW) | Capacity Factor | Nameplate Capacity (MW) | Potential Operating Hours | Capacity Factor |
| Dresden | 01/31/12 | 2,599,011 | 8,064 | 540 | **60%** | 678.3 | 8,784 | **44%**[311] |
| Fremont | 01/20/12 | 2,582,396 | 8,328 | 667.3 | **46%** | 739.5 | 8,784 | **40%** |

In the state goal calculation, EPA uses the following steps to determine the amount of NGCC capacity to be redispatched:

(1) Determine the total net generation from all existing NGCC units in 2012

(2) Calculate the "potential" NGCC capacity that could be redispatched if the entire NGCC fleet in the state operated at a 70% capacity factor as follows: Potential Redispatch Capacity (MWh) = (existing NGCC capacity) * (8784 hours/yr) *70% [Note EPA incorrectly uses nameplate capacity in this calculation]

(3) Calculate the amount of NGCC redispatch to be used in building block 2 as follows: State NGCC redispatch (MWh) = "Potential" NGCC capacity at 70% - 2012 NGCC net generation

[309] Dresden was commissioned 01/31/12 per Appalachian Power Company filing to the VaSCC on 03/20.12; Fremont was commissioned on 01/20/12 per AMP, Inc. filing to the Ohio Power Siting Board on 02/23/12.
[310] Net Generation data per 2012 EIA-923 report. Summer and Nameplate Capacity per 2012 EIA-860 report.
[311] 44% is based on the correct 2012 net generation value for Dresden. As discussed in the comments that follow EPA used an incorrect net generation value for Dresden, which would have indicated an 8% capacity factor for the facility using EPA's methodology.

Thus, the amount of redispatch that EPA computed for certain states is inflated by the inclusion of the capacity that units did not generate (and were not available to generate) prior to being commissioned in 2012. If units commissioned during 2012 remain in the calculation of the "existing" category of units, then the potential redispatch for the existing NGCC fleet should be derived based on the historic capacity factor, *not* on the EPA approach of using historic generation. Using the historic capacity factor approach accounts for the fact that units were commissioned in 2012 and appropriately weighs the in-service date into the redispatch calculation. This calculation would involve the following:

(1) Determine the total net generation from all existing NGCC units in 2012

(2) Calculate the potential operating hours for each existing NGCC unit in 2012 based on the date that each unit was commissioned
Potential operating hours for units in-service prior to 2012 = 8,784 hours
Potential operating hours for units commissioned in 2012 = 8,784 hours – (time prior commissioning)

(3) Calculate the maximum potential 2012 NGCC generation for each existing unit:
Maximum potential generation = potential operating hours (from step 2) * net summer capacity

(4) Determine the weighted potential net generation from existing NGCC units in 2012

(5) Calculate the weighted 2012 capacity factor for the state NGCC fleet
2012 NGCC capacity factor = 2012 net generation (step 1) / 2012 total potential generation (step 4)

(6) Determine the amount of redispatch as a % capacity factor:
Amount of redispatch (% capacity factor) = 70% capacity factor – 2012 NGCC capacity factor (step 5)

(7) Determine the amount of redispatch in MWh:
Amount of redispatch (MWh) = redispatch capacity factor (step 6) * net summer capacity * 8784 hrs.

Using this approach for the Dresden and Fremont Plant, along with the correction of other errors noted throughout the comments would reduce the amount of NGCC redispatch calculated for Ohio from 5,793,981 to 439,452 MWh – a 92% reduction from EPA's calculated amount.[312] Consider another example, the H.F. Lee Plant, which is a 920 MW NGCC unit commissioned on December 31, 2012. The unit was available to operate *for only one day in 2012*, yet EPA's calculation assumes that the unit was available for the entire year. EPA used the nominal nameplate capacity (1,068 MW) to determine that approximately 6,548,976 MWh (equivalent of a 70% capacity factor) was available to be redispatched from this facility because it would have had a near 0% baseline capacity factor in 2012 by EPA's logic.[313] These

[312] A summary of the revised Ohio calculations is provided in Appendix B.
[313] Estimate Redispatch = 6,548,976 MWh = 1,068 MW (nameplate capacity from EIA860) * (8784 hours/yr – 24 potentially in-service) *70%

6,548,976 MWhs represent over 20% of the total redispatch calculated for the state of North Carolina – even though the H.F. Lee plant had not been commissioned until the last day of the year![314] The North Carolina goal is made even more unrealistic by the commissioning of another NGCC unit at the Dan River plant on December 10, 2012. If the associated "redispatch" capacity from Dan River is considered as well, then nearly 40% of the redispatch capacity calculated for North Carolina was from units that had not been commissioned or available to operate for most of the year. Other examples of this issue are as follows:

| State | Plant | In-Service Date | Potential Operating Hours (based on in-service date) | EPA Calculated Potential Operating Hours | % Difference In-Service vs. EPA Operating Hours |
|---|---|---|---|---|---|
| OH | Fremont[315] | 01/20/12 | 8,328 | 8,784 | -5% |
| OH | Dresden[316] | 01/31/12 | 8,064 | 8,784 | -8% |
| GA | Jack McDonough[317] | 04/26/12 | 6,000 | 8,784 | -32% |
| TN | John Sevier[318] | 04/30/12 | 5,904 | 8,784 | -33% |
| MS | Moselle[319] | ~05/01/12 | 5,928 | 8,784 | -33% |
| ID | Langley Gulch[320] | 06/29/12 | 4,464 | 8,784 | -49% |
| SD | Deer Creek[321] | 08/01/12 | 3,672 | 8,784 | -58% |
| CA | El Centro[322] | 10/05/12 | 2,112 | 8,784 | -76% |
| CA | Tracy[323] | 11/01/12 | 1,464 | 8,784 | -83% |
| CA | Lodi[324] | 11/01/12 | 1,464 | 8,784 | -83% |
| MS | Moselle[325] | ~11/01/12 | 1,464 | 8,784 | -83% |
| NC | Dan River[326] | 12/10/12 | 504 | 8,784 | -94% |
| NC | H.F. Lee[327] | 12/31/12 | 24 | 8,784 | -99.7% |

[314] EPA Calculated 31,918,596 MWh of NGCC redispatch. "Goal Computation Technical Support Document – Appendix 1." EPA. June 2014. Docket ID # EPA-HQ-OAR-2013-0602. (6,548,976 MWh H.F. Lee / 31,918,596 MWh North Caroline = 20.5%)
[315] Fremont was commissioned on 01/20/12 per AMP, Inc. filing to the Ohio Power Siting Board on 02/23/12.
[316] Dresden was commissioned 01/31/12 per Appalachian Power Company filing to the VaSCC on 03/20.12.
[317] www.prnewswire.com/news-releases/georgia-power-completes-plant-mcdonough-atkinson-conversion-to-natural-gas-176265521.html
[318] www.tva.com/sites/johnsevier_cc.htm
[319] www.hattiesburgamerican.com/story/news/local/2014/05/22/officials-give-media-tour-plant-moselle/9456577/
[320] www.transmissionhub.com/articles/2012/07/idaho-power-brings-online-300-mw-langley-gulch-gas-plant.html
[321] https://puc.sd.gov/Dockets/Electric/2009/el09-015.aspx
[322] www.energy.ca.gov/sitingcases/all_projects.html
[323] www.energy.ca.gov/sitingcases/tracyexpansion/
[324] www.energy.ca.gov/sitingcases/lodi/
[325] www.hattiesburgamerican.com/story/news/local/2014/05/22/officials-give-media-tour-plant-moselle/9456577/
[326] www.bizjournals.com/triad/prnewswire/press_releases/North_Carolina/2013/01/03/CL36348
[327] Id.

EPA's proposed 111(b) rule for new units included a technical support document for combustion turbines that was designed to evaluate potential differences in emission rates due to various unit-specific factors. The evaluation focused on NGCC units that were commissioned from 2000 through 2010. With respect to new NGCC units that were commissioned after 2010, EPA noted that:

> Although new NGCC units came online in 2011, none are included here as *they lacked sufficient data* to calculate a 12-month rolling average, *the basis for determining a standard of performance.*[328]

EPA should apply this same rationale and exclude units commissioned in 2012 from the calculation of existing NGCC units to be redispatched. These units could then be separately included in the "under construction" category of units within building block two calculation. At a minimum, EPA must at least revise the state goal calculations to properly account for the date that new units were commissioned in 2012.

4. EPA must resolve significant data quality issues

A number of data quality issues have been identified in the building block two calculations related to the reported $CO_2$ emissions and net generation reported for various units. One of the most significant data quality errors pertains to the 2012 net generation data that EPA considered for the AEP Dresden NGCC unit in Ohio. EPA relied upon the 2012 EIA-923 report for generation data, which incorrectly reported the generation for the Dresden NGCC unit as 470,486 MWh, instead of the 2,599,011 MWh the unit actually generated. In reviewing the error, it was determined that AEP had correctly reported the generation to the EIA, however a publication error by EIA led to the 923 report only reporting generation data for November and December of 2012. AEP notified EIA of this publication error on August 21, 2014. At the request of EIA, AEP resubmitted the 2012 generation data for the Dresden plant on August 27, 2014. Subsequently, AEP followed up with EIA on September 3, October 16, and most recently on November 19, 2014, regarding the status of revising and republishing the 2012 EIA-923 report with the corrected information. EIA's most recent response on November 20, 2014 indicates that the agency is targeting "mid-January" of 2015 for the revision.

[328] Combustion Turbine Standard TSD. EPA. 2014. Docket #: EPA-HQ-OAR-2013-0495-0082. p.2.

Another data quality concern pertains to EPA's confusion regarding the configuration and operation the AEP Arsenal Hill and J. Lamar Stall ("Stall") generation units in Louisiana. The Arsenal Hill plant is a natural gas steam boiler unit that was commissioned in 1960. The Stall plant is a natural gas combined cycle unit commissioned in 2010 that consists of two combustion turbine and heat recovery steam generator trains that supply steam to a common steam turbine. The Stall plan is co-located at the Arsenal Hill facility. Both units are covered under the same Title V operating permit, which identifies the Arsenal Hill unit as 5A and the two Stall combustion turbine units as 6A and 6B.[329] The Clean Air Markets Division database identifies $CO_2$ emissions from the units using a common Arsenal Hill facility name (e.g. Arsenal Hill 5A, Arsenal Hill 6A, and Arsenal Hill 6B). This nomenclature led to emissions from the facility being incorrectly considered in the Louisiana state goal calculations. A summary of the error and the correct values are provided in the table below.

| Data Source: EPA eGRID Database | AEP | EPA eGRID Database | EPA CAMD | Calculation eGRID-CAMD |
|---|---|---|---|---|
| Plant / Unit | Unit Type | 2012 CO2 (tons) | 2012 CO2 (tons) | Difference |
| Arsenal Hill 5 | Gas Steam Boiler | 1,484,758.0 | 38,301 | 1,446,457 |
| J. Lamar Stall 6A | NGCC (Comb Turbine) | 431,511.0 | 759,793 | |
| J. Lamar Stall 6B | NGCC (Comb Turbine) | 431,511.0 | 686,664 | |
| J. Lamar Stall 6STG | NGCC (Steam Turbine) | 600,363.1 | none (not applicable) | |
| | Stall Total = | 1,463,385.1 | 1,446,457.0 | 16,928.1 |

Accordingly, $CO_2$ emission data used by EPA to calculate the proposed Louisiana state goal should be updated to accurately reflect the emissions associated with the Arsenal Hill and Stall units.[330] Specifically (if EPA continues to use the building block approach and 2012 data), the $CO_2$ emissions data for Arsenal Hill should be revised to 38,301 tons (from 1,484,758 tons). For the J. Lamar Stall facility, the $CO_2$ emission data should be revised to 1,446,457 tons (from 1,462,385.1 tons).

A summary of other data discrepancies identified is detailed in Appendix B. EPA must correct these issues and perform a thorough quality assurance check of all the data inputs and calculations used to calculated the state goals.

[329] Title V Permit #0500-00008-V2. Louisiana Department of Environmental Quality. June 7, 2010.
[330] EPA should correct $CO_2$ data listed in Appendix 7 of the Goal Computation Technical Support Document.

5. Building block two calculations are incorrect for all states identified by EPA as having applicable NGCC units

The data quality issues and methodological errors detailed above are not limited in scope, but are present in the building block two calculations for every state with NGCC capacity. The impact of these concerns is significant. For example, correcting these errors was determined to reduce the amount of NGCC redispatch that EPA calculated by 51% in Louisiana and 92% in Ohio.[331] While not a complete analysis, the matrix that follows at the end of this section highlights the scope of building block two calculation issues, alone, that have been identified for each state with NGCC capacity.

6. EPA must revise all aspects of the proposed rule that are impacted by the data quality and methodological issues identified for building block 2

Any attempt to correct the litany of concerns or determine how these corrections impact state goal calculations, "flexible" compliance strategies, reliability evaluations, and cost-benefit analyses is too complex to complete within the public comment period. Given the egregious nature and scope of concerns to be resolved in building block 2 alone, EPA must withdraw the current proposal, address these issues, and publish a new proposed rule for public comment.

## I. Building Block 2 Comments related to EPA's NODA

1. Phased Implementation of Building Block 2

EPA requested comment on whether or not the building block 2 should be phased-in to prevent the possibility of early unit retirements and related potential reliability issues. Aside from the legal, technical, and practical concerns with building block 2, a phased-in approach would offer additional flexibility for states to attempt to address these concerns in developing an state plan within the aggressive implementation schedule proposed by EPA.

2. Consideration of Minimal NGCC Utilization in the BSER

EPA requested comment whether the BSER determination should include a minimum utilization of natural gas in all states and assumes that states that are below that minimum utilization would either build new NGCC to facilitate additional redispatch or would co-fire gas at existing coal-fired boilers. Such an approach would be arbitrary and infringe on state energy planning and regulation authority. It also disregards the remaining useful life of the coal units

[331] The revised redispatch calculations for Ohio and Louisiana are detailed in Appendix B.

located in those states. Therefore, the BSER determination should not include a minimum natural gas utilization assumption.

With respect to natural gas co-firing, EPA initially dismissed it from the BSER on the basis of cost by noting that "that other approaches could reduce $CO_2$ emissions from existing EGUs at lower cost."[332] EPA's estimated costs of avoided $CO_2$ from co-firing are "approximately \$83 to \$150 per metric ton," which is significantly more than other options analyzed within the BSER building block determination and subsequent IPM analysis.[333] The agency also notes that significant lateral pipeline expansion could be required to supply gas to co-firing facilities. These costs can be extremely significant for units that are located some distance from pipelines or pipelines with excess capacity. Furthermore, the ease and capital cost associated natural gas co-firing is highly dependent on a multitude of unit-specific technical factors. As such, EPA cannot make broad generalizations of co-firing costs or achievability and therefore cannot include co-firing as part of a BSER determination

3. Regional Approach to Building Block 2

EPA requested comment on whether NGCC redispatch should be viewed from a regional perspective. While the electric sector operates in a regional context and a regional view is important in assessing impacts of this proposed rule, it is unclear how a state could be apportioned an emission reduction requirement based on the utilization of out-of-state resources. Also, drawing this regional distinction would be difficult to accomplish without robust analysis of the supporting infrastructure that would make such dispatch feasible. As previously noted, even at the state level, significant constraints exist to NGCC redispatch. A regional approach could exacerbate these limitations. While such an approach could help to levelize the required emission reductions by removing artificial state boundaries in the redispatch determination, any regional determination would be also arbitrary, given the number of factors that influence feasibility. As such, a regional approach to redispatch is not warranted under this proposal.

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[332] 79 Fed. Reg. 34857 (June 18, 2014)
[333] Id.

**Summary of Methodology & Data Quality Issues (observations to date only, not a comprehensive review)**

| | Incorrect Use of Nameplate Capacity | "Existing NGCC" includes units that are not NGCC units or affected sources | Incorrect Consideration of NGCC units commissioned after 2011 | Incorrect Consideration of Cogeneration units | Data Quality issues identified or air permit limits that affect redispatch |
|---|---|---|---|---|---|
| Alabama | Yes | | | n/a | |
| Alaska | Yes | Yes | Yes | n/a | |
| Arizona | Yes | | | Yes | |
| Arkansas | Yes | | | Yes | |
| California | Yes | Yes | Yes | Yes | |
| Colorado | Yes | | Yes | Yes | Yes |
| Connecticut | Yes | | | Yes | Yes |
| Delaware | Yes | | | n/a | |
| Florida | Yes | Yes | Yes | Yes | Yes |
| Georgia | Yes | | Yes | Yes | Yes |
| Idaho | Yes | | Yes | n/a | Yes |
| Illinois | Yes | | | Yes | |
| Indiana | Yes | Yes | | Yes | |
| Iowa | Yes | | | n/a | Yes |
| Kentucky | Yes | n/a | Yes | n/a | n/a |
| Louisiana | Yes | Yes | Yes | Yes | Yes |
| Maine | Yes | | | n/a | |
| Maryland | Yes | | | n/a | |
| Massachusetts | Yes | | | Yes | Yes |
| Michigan | Yes | | | Yes | Yes |
| Minnesota | Yes | | | Yes | Yes |
| Mississippi | Yes | | Yes | n/a | |
| Missouri | Yes | | | n/a | |
| Nebraska | Yes | | | n/a | |
| Nevada | Yes | | | Yes | |
| New Hampshire | Yes | | | n/a | |
| New Jersey | Yes | | | Yes | |
| New Mexico | Yes | | | n/a | |
| New York | Yes | | | Yes | Yes |
| North Carolina | Yes | | Yes | n/a | Yes |
| Ohio | Yes | | Yes | n/a | Yes |
| Oklahoma | Yes | | | Yes | |
| Oregon | Yes | | | Yes | |
| Pennsylvania | Yes | | | Yes | |
| Rhode Island | Yes | | | n/a | Yes |
| South Carolina | Yes | | | Yes | |
| South Dakota | Yes | | Yes | n/a | |
| Tennessee | Yes | | Yes | n/a | |
| Texas | Yes | | Yes | Yes | |
| Utah | Yes | Yes | Yes | n/a | |
| Virginia | Yes | | Yes | Yes | Yes |
| Washington | Yes | | | Yes | |
| Wisconsin | Yes | | | Yes | Yes |
| Wyoming | Yes | n/a | Yes | n/a | n/a |

## VII. Building Block 3 is unachievable

The inclusion of renewable energy in the determination of the best system of emission reductions is fundamentally flawed due to a number of legal, technical, economic, and practical issues. These concerns are related to EPA having:

- overstated its regulatory authority and interpretation of applicable requirements;
- mischaracterized and misapplied state renewable portfolio standards and experience;
- insufficiently evaluated the technical potential and cost of renewable options;
- failed to fully evaluate or provide sufficient guidance on interstate considerations;
- used arbitrary assumptions to develop renewable energy regions and state goals; and
- ignored development challenges related to the expansion of both intra- and interstate transmission resources, regulatory processes, cost allocation, and timing.

### A. Renewable resources must be excluded from the determination of the best system of emission reductions for existing fossil fuel electric generating units

#### 1. Renewable resources are not affected sources under 111(b) and therefore cannot be regulated under 111(d)

As detailed extensively above, EPA's authority is constrained by the clear language of section 111 to establishing guidelines that will assist the states in developing performance standards for "designated facilities" that would be subject to a federal standard "if they were new."[334] EPA's January 2014 proposal applies to EGUs that are currently regulated under Subparts Da and KKKK of 40 CFR Part 60, with certain slight modifications. Nothing in the CAA gives EPA the authority to reach outside the listed source category and base its determination of the BSER on the continued operation and future expansion of facilities that not only are outside the listed source category, but that emit no pollutants at all, and therefore are not regulated under the CAA. EPA's recent discovery of this broad-ranging regulatory authority in the word "system" is the kind of legislative interpretation that the Supreme Court has affirmed will be greeted with skepticism, because it would bring about an "enormous and transformative expansion of EPA's regulatory authority without clear Congressional authorization."[335] EPA must eliminate building block 3 from its proposal.

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[334] 42 U.S.C. §7411(d).
[335] *UARG v. EPA,* 134 S.Ct. at 2444.

2. EPA has infringed upon States Tenth Amendment Rights

Not only does the CAA itself constrain EPA's authority and preclude the inclusion of renewable energy resources in a section 111(d) standard, but the expansion of EPA's regulatory authority in this way directly infringes upon powers reserved to the states, contrary to the Tenth Amendment to the U.S. Constitution. Few industries are as heavily regulated as the utility industry, precisely because of the importance of adequate and affordable supplies of electricity to the national economy. But the balance between federal and state authority was drawn long ago, and is codified in the Federal Power Act. While there is a sufficient national interest to justify federal regulation of interstate sales of electricity and the operation of the bulk electric system, states are granted the authority to regulate the generation of electricity, including determining the type, size, location and design of individual generating resources.[336] As outlined in UARG's comments, the FPA's long history of implementation, since its enactment in 1935, has maintained this clear distinction between state and federal authority.[337]

Moreover, the CAA itself directly addresses the interrelationship between EPA and other federal agencies, and EPA and the states. Section 310 of the CAA states that the CAA "shall not be construed as superseding or limiting the authorities and responsibilities, under any other provision of law, of . . . any other Federal officer, department, or agency."[338] Congress also expressly recognized that "air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments...[339] Sections 110 and 111 reflect that assignment of primary responsibility to the states, and EPA cannot reinterpret words that have long been understood to require control of pollution at the source to authorize broader control over the entire scope of energy production and use.

Federal courts have repeatedly rejected attempts by EPA to compel states to enact or administer a federal program without express Congressional authorization. Yet here, on the basis of a dictionary definition that strains the meaning of "system" beyond any reasonable bounds, EPA asserts the authority to usurp state legislative authority and mandate measures that

[336] 16 U.S.C. §824(a) and (b).
[337] *See also Fed. Power Comm. v. S. Cal. Edison Co.,* 376 U.S. 205, 215 (1964) (Congress meant to draw a bright line easily ascertained, between federal and state jurisdiction . . .).
[338] 42 U.S.C.§7610(a).
[339] 42 U.S.C. §7401(a)(3).

reach far beyond the regulated source category, into the exclusive province of state energy policy decisions, by creating a system where without the inclusion of zero-emitting generation in its compliance calculus, a state has no hope of developing a plan that actually complies with the goals established by EPA.

In *Maryland v. EPA,* the Fourth Circuit rejected EPA's attempt to require the state to enact a specific transportation control plan, stating that, "if there is any attribute of sovereignty left to the states it is the right of their legislatures to pass, or not to pass, laws."[340] Congress itself has tried and failed to enact federal renewable portfolio standards on numerous occasions.[341] EPA's authority under Section 111(d) simply is not capacious enough to support a system of state goals that would, in effect, require the state to legislate such standards in order to successfully implement EPA's guidelines.

### B. EPA's use of existing renewable portfolio standards to determine state renewable energy targets is fundamentally flawed

EPA developed building block 3 goals based on an arbitrary assignment of states into regions that presume that neighboring states will have similar opportunities for the development of renewable resources. The agency then used an average of mandatory state renewable portfolio goals in these regions to assume that what may be technically and economically achievable in terms of renewable development and generation in some states will be achievable by all states within each respective region. This approach is flawed in that EPA:

- mischaracterized the design and overstated the stringency of existing state RPS;
- incorrectly assumed that existing RPS represent achievable targets for renewable resource development in other states;
- ignored the renewable energy experience and perspectives of states with no RPS;
- did not fully consider significant geographic and economic differences between states in a region; and
- relied upon "effective" 2020 renewable energy targets that have not been adequately demonstrated and may not be representative of specific RPS requirements.

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340 530 F.2d at 225. *See also, Brown v. EPA*, 521 F.2d 827 (9th Cir. 1975); *District of Columbia v. Train*, 521 F.2d 971(D.C. Cir. 1975).

341 *See, e.g.,* S. 1567 (10th Congress, 2007); S. 741 (112th Congress, 2011); H.R. 983 (109th Congress 2005); H.R. 5756 (107th Congress, 2002) ; each of these bills would have amended the Public Utility Regulatory Policy Act and provided for a renewable portfolio standard to be administered by the Secretary of Energy.

1. EPA has mischaracterized and overstated the renewable energy development associated with existing renewable portfolio standards

Based on a review of the mandatory RPS that EPA considered, it is readily apparent that the design of state programs varies significantly and represents an assortment of different provisions. The individual and cumulative impact of these unique provisions reduces the "effective" amount of renewable resources that EPA can reasonably rely on as equivalent to its renewable energy goals. EPA ignored these factors in the proposed rule, but must fully consider and correct for the impact of these nuances if building block 3 remains a component of the final guidelines. Below is summary of the factors that impact the stringency of state renewable energy goals:

Hydroelectric Generation

Most state RPS include existing and/or new hydroelectric generating units as eligible resources for demonstrating compliance.[342] The contribution of existing hydroelectric units is included in the "effective" 2020 RPS rates that EPA used to calculate the renewable energy goals for each region. However, in using these regional targets to develop regional growth rates and individual state renewable goals in building block three, EPA relies on baseline renewable generation from 2012 that excludes hydroelectric generation:

> For the purpose of calculating a baseline level of RE generation in each state, the EPA adopted a broad interpretation of RE generation to include any non-fossil renewable type, with the exception of generation from existing hydroelectric power facilities.[343]

In other words, state RPS targets designed to *include* existing hydro units are unfairly used to establish regional renewable energy goals in building block 3 that *exclude* existing hydro generation units.

Biomass Generation

As with hydroelectric generation, many state RPS are designed to include the contributions from biomass resources. EPA uses the contribution of biomass resources to determine the baseline renewable generation for each state that is then used to develop the building block 3 goals. However, EPA had not made a determination of whether states would be able consider biomass

[342] Database of State Incentives for Renewables & Efficiency. U.S. DOE. www.dsireusa.org/rpsdata/RPSspread042213.xlsx
[343] "GHG Abatement Measures TSD." EPA. June 2014. p.4-5. (emphasis added)

for compliance purposes at the time of its proposal. On November 19, 2014, EPA released its second draft of the *Framework for Assessing Biogenic Carbon Dioxide Emissions from Stationary Sources,* [344] and anticipates seeking further review of the *Framework* through the Science Advisory Board and public comment.[345] However, EPA must be consistent in accounting for biomass emissions, both in its state goal calculations and in its regulations for compliance demonstrations, by either adjusting the "effective" 2020 RPS rate to exclude biomass, or to definitively affirm that states can rely on biomass as a carbon neutral resource in developing implementation plans. The revised *Framework* does not provide definitive answers on these issues, only proposed calculations that require detailed inputs in order to determine whether, and to what extent, biogenic energy sources may be relied on to reduce $CO_2$ emission rates or mass emissions in the context of the proposed CPP. At present, all EPA has committed to do is to second-guess state plan submittals based on criteria that it has not clearly defined.

<u>Unique Eligible Resources</u>

Some RPS apply to renewable resources that are unique in that state, and which may have limited or no applicability to other states in the regions defined by EPA in building block 3. Including the potential contribution from these uniquely defined and limited resources in the calculation of the renewable energy average for the regions creates an unrealistic expectation that other states without such resources can achieve a comparable level of renewable development. Some of these uniquely eligible resources contained in existing RPS include:

- ocean tidal and ocean thermal resources (i.e. Delaware)
- offshore wind energy (i.e. Maryland)
- energy efficiency (i.e. North Caronia, where up to 40% of RPS can met with EE)
- energy recovery from swine and poultry waste (i.e. North Carolina, ~10% of RPS must be met from these resources)
- coal mine methane (i.e. Pennsylvania)
- "clean coal" (i.e. Ohio)
- municipal solid waste (i.e. Michigan)
- "advanced nuclear" (i.e. Ohio)

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[344] Revised *Framework for Assessing Biogenic $CO_2$ Emissions from Stationary Sources,* Second Draft, November 2014.

[345] Memorandum from Janet G. McCabe, Acting Administrator, Office of Air and Radiation to Air Directors, Regions 1-10, *Addressing Biogenic Carbon Dioxide Emissions form Stationary Sources* (November 19, 2014).

- “densified fuel pellets” (i.e. Wisconsin)
- pyrolysis of municipal solid waste (i.e. Colorado)
- solar light pipes (i.e. Wisconsin)
- compressed air, fly wheel, and battery storage (i.e. Montana)
- solar pool heating (i.e. Nevada)

Credit Multipliers

Credit multipliers are designed to incentivize specific technologies or programs to be developed. For instance, if a specific renewable resource is constructed within a state, then each MWh produced by that resource would be counted as 2 MWh. As a result of the multiplier, the actual state RPS targets are less stringent that the absolute percentage target would indicate. A variety of such provisions were identified in the review of existing RPS programs, including renewable resources that are:

- located within state boundaries;
- using equipment manufactured within the state;
- constructed by state residents or by an “approved apprenticeship program;”
- constructed by a specific date;
- using specific technologies;
- operated during peak demand periods; or
- qualified as “community-based” projects.

Out-of-State Renewable Energy Credits

Most state RPS accept out-of-state renewable energy credits (“RECs”) as part of the compliance demonstration program. For instance, the state of North Carolina allows for up to 25% of its RPS requirements to be met by out-of-state resources, while Ohio now allows up to 100% of the renewable energy used to satisfy its requirements to come from outside the state. EPA acknowledges the dependence state RPS compliance on out-of-state resources by noting that:

> [EPA’s] approach applies the...growth factors and regional RE targets to state-level generation, where as the state-level RPS requirement upon which they are based are not necessarily applied in practice to generation that is produced within the relevant state.[346]

[346] “GHG Abatement Measures TSD.” EPA. June 2014. p.4-19.

Alternative Compliance Payment ("ACP") programs

Many existing state RPS contain provisions that establish alternative compliance payment programs if the regulated entity is unable to secure or develop the renewable resources required by the program. These programs were created largely to protect consumers if renewable energy supplies become uneconomic or unavailable. Such ACP programs are designed so that entities pay a $/MWh amount for any shortfall of renewable energy obligations. The use of ACP programs to demonstrate compliance is indicative of the difficulty that some states envisioned for meeting RPS even with the subsidies provided in the form of federal production tax credits ("PTC") and investment tax credits ("ITC"). EPA should adjust state targets where ACP has historically or can reasonably be predicted to reduce the amount of renewable energy that is actually deployed under the RPS in the future.

Cost Mitigation Measures

Several state RPS programs contain cost mitigation measures whereby the state has established caps on the impact to retail rates associated with the cost of renewable resources. For instance, if retail rates increase by a certain amount (i.e. 1 or 2%), then the RPS is effectively lowered for that compliance year to avoid excessive consumer cost impacts. Absent additional governmental subsidies which expired at the end of 2013 (PTC) and will expire at the end of 2016 (ITC), it is more likely that these existing RPS caps will be triggered as additional resources are added to achieve future RPS requirements. EPA should not include renewable goals for any state that can reasonably be predicted to exceed the retain rate caps already in effect in those states.

Reliability Mitigation Measures

Some states have included exit ramps from RPS to address potential reliability concerns regarding the impacts of increased capacity from intermittent resources. EPA should consider including such a provision to allow state to issue variances if reliability impacts would otherwise occur.

Retail Sales vs. Capacity Based Standards

The targets for most state RPS are based on the percentage of retail sales in the state. However, some RPS programs, such as in Kansas, are designed as a generating capacity-based standard. EPA failed to account for these differences in the design of state standards in terms of the percentage reduction targets for individual states. Although EPA recognized these differences, it incorrectly noted that it "did not include targets that were capacity-based" in the building block 3 calculation of regional goals. In fact, the Kansas RPS was the sole basis for developing the goal for the South Central region.[347]

RPS based on State Sales vs. Block 3 Goal base on Total Generation

Nearly all the state RPS programs are designed around targets related to a percentage of state retail sales. EPA calculated regional renewable energy goals based on these retail sales-based RPS, but then applied that calculated rate to 2012 total generation, not retail sales, for that state. This creates an "apples and oranges" comparison that may translate into unrealistic expectations for what a specific region or state may or may not be able to achieve. In particular for energy-exporting states, retail sales may be a better estimation of in-state usage, while wholesale sales often represent energy exports. As such, the state is unable to influence customer behavior, or require addition of renewable resources to meet customer demand for the portion of generation that is exported to other states. EPA should examine this "disconnect" between the state-established RPS standards and its proposed imposition of a goal based on a wholly different base. This kind of adjustment would also allow EPA to take into account in setting goals the ownership of generating facilities by multi-state utilities, or by multiple partners, some of whom may be located in adjacent states.

State RPS Implementation Schedules

The implementation schedule for state RPS programs is generally less aggressive than the proposed schedule for implementing the Clean Power Plan. States structured their programs in this fashion in part to allow for a more gradual, cost-effective, and practically achievable ramp rate for increasing renewable resources. Based on the review of the RPS considered by EPA, the implementation period was commonly 15 to 18 years for most states, but up to 20 years in Montana, versus the 10-12 year period envisioned by EPA, depending on the approval date for state plans. Additionally, EPA has assumed that states would ramp up renewable generation in advance of final state plans being approved, but has not clarified if and how such activities would receive credit under the final guidelines. While EPA has requested comment on how

[347] Id. p.4-10.

early actions could be taken into account in determining compliance, its proposal appears to give credit only for renewable generation that is provided to the grid in a specific year, and does not allow for flexible systems like banking renewable credits for use in future years.

<u>Revisions State RPS</u>

Most existing RPS have been revised several times in order revise expected targets, alter the design of the program or extend the compliance schedule based a number of factors, including more realistic expectations on the cost-effective development of new resources. In some instances such as Ohio, the state has reduced the stringency of the RPS and increased compliance flexibility. In 2014, Ohio did both by freezing the ramp-up schedule of its RPS program and by expanding the program to allow of out-of-state resources to be used to fully meet the Ohio RPS, if necessary.

If renewable energy programs remain a part of the final guidelines, EPA must recognize the need for flexibility as an approved part of state plans, and allow for mid-course revisions, banking of excess credits, and other mechanisms that already exist as part of many of the standards EPA used as the basis for its proposal. In the absence of such mechanisms, there is no basis for EPA's assertion that these programs represent a level of performance that has been "adequately demonstrated" as required by the CAA. As shown below, 23 of the 27 programs examined by EPA have been revised, 19 of them multiple times, over the course of their implementation. Below is a summary of revisions made to the RPS considered by EPA:[348]

[348] "Renewables Portfolio Standards in the United States: A Status Update." Barbose. G. Lawrence Berkeley National Laboratory. Sept 22, 2014. www.cesa.org/projects/state-federal-rps-collaborative/rps-resource-library/resource/renewables-portfolio-standards-in-the-united-states-a-status-update-galen-barbose

| State | Year RPS First Enacted | Number of Revisions Since RPS first Enacted | Most Recent RPS Revision |
|---|---|---|---|
| Delaware | 2005 | 4 | 2011 |
| D.C. | 2005 | 2 | 2011 |
| Maryland | 2004 | 6 | 2013 |
| New Jersey | 1999 | 5 | 2012 |
| Ohio | 2008 | 2 | 2014 |
| Pennsylvania | 1998 | 2 | 2007 |
| North Carolina | 2007 | 1 | 2011 |
| Kansas | 2009 | 0 | 2009 |
| Michigan | 2008 | 0 | 2008 |
| Minnesota | 1994 | 6 | 2013 |
| Missouri | 2008 | 0 | 2008 |
| Illinois | 2007 | 4 | 2014 |
| Wisconsin | 1998 | 4 | 2014 |
| Connecticut | 1998 | 6 | 2013 |
| Maine | 1997 | 2 | 2009 |
| Massachusetts | 1997 | 5 | 2014 |
| New Hampshire | 2007 | 1 | 2012 |
| New York | 2004 | 2 | 2012 |
| Rhode Island | 2004 | 1 | 2009 |
| Arizona | 1991 | 2 | 2006 |
| California | 2002 | 2 | 2011 |
| Colorado | 2004 | 4 | 2013 |
| Montana | 2005 | 1 | 2013 |
| Nevada | 1997 | 5 | 2013 |
| New Mexico | 2000 | 5 | 2013 |
| Oregon | 2007 | 2 | 2014 |
| Washington | 2006 | 0 | 2006 |

2. EPA's methodology for calculating renewable energy goals is flawed

EPA's calculation of renewable energy goals in building block 3 is fundamentally flawed because it:

- excludes consideration of states without mandatory RPS programs;
- is premised on "effective" 2020 rates calculated by EPA that do not reflect the specific requirements within those existing RPS programs;
- relies upon renewable energy targets that have not been adequately demonstrated; and
- ignores individual state determinations in favor of regional renewable energy benchmarks that are arbitrarily assigned.

EPA calculated renewable energy goals for six agency-defined regions by averaging the "effective" 2020 targets of the existing mandatory RPS programs in that region. For states without mandatory RPS, the agency made no effort to investigate or defer to prior state determinations of the adequacy or cost-effectiveness of integrating renewable resources into their generation portfolios. Had EPA done so, there would have been no reason to deviate from the conclusions reached by these state legislatures and regulators, nor is there any reason to attempt to impose more stringent requirements in the establishing the BSER. Instead, EPA ignored the decision of those states without an RPS in the calculation of the regional average renewable energy goals because the agency did not deem them to be "*leading states*."[349] The agency failed to consider that perhaps these states have previously evaluated renewable energy opportunities and determined that they were not currently technically feasible or cost-effective. Instead, EPA's process forces states to conform to the policies developed by other states that are based on different considerations of feasibility, cost, and public interest.

Louisiana is an example of one state that has evaluated opportunities for renewable energy and determined not to implement an RPS program. In 2010, the Louisiana Public Service Commission approved a Renewable Energy Pilot Program for the state with the goal of determining whether an RPS is suitable for Louisiana. As part of the program, an AEP subsidiary, Southwest Electric Power Company ("SWEPCO"), conducted an all-source Renewable Request for Proposal. Bids were received for 46 proposed renewable energy projects. Only 14 were for projects to be located in Louisiana (one wind, five solar, three waste

349 "GHG Abatement Measures TSD." EPA. June 2014. p.4-1.

heat recovery, four biomass, and one landfill gas project). The balance of bids came from other states within the same RTO, the Southwest Power Pool ("SPP") states. The most practical source of renewables that could be secured to serve SWEPCO customers was from a portion of a wind project being developed in Kansas. Interestingly, the single wind project that was proposed to be located in Louisiana was more than three times the cost of the selected wind energy bid from Kansas. None of this experience was considered by EPA in the proposed rule, and Louisiana's decision to not to establish an RPS based on the current lack of cost-effective and technically feasible renewable resources is ignored in the calculation of the South Central region goal.

Comments submitted by the Virginia State Corporation Commission ("SCC") further highlight the concern that state decisions to not establish RPS programs has been ignored by EPA in the building block three calculations. The SCC notes that:

> The fact that Virginia does not have a mandatory RPS requirement is not considered at all in EPA's calculations or the extrapolation of other States' RPS requirements on Virginia...
>
> Even if the legislative process of one state could establish a level of renewable generation that has been demonstrated in Virginia, that would not justify giving less weight – indeed, not weight at all – to Virginia's legislative determination to not impose RPS requirements. EPA's math is wrong.[350]

The EPA's use of "effective" 2020 RPS requirements reflects rates that are overstated due to the failure to consider RPS provisions that reduce the overall stringency of individual state requirements. In addition, the future effective 2020 RPS rates have not been "*adequately demonstrated*," which the Clean Air Act defines is a necessary prerequisite for determining the "best system of emission reduction."[351] In the design of most RPS, states acknowledged the challenges associated with increased development and utilization or renewable resources by including provisions that gradually increase implementation over two decades, that allow for alternative compliance plans in lieu of renewable resource development, and that reduce the stringency of standards in order to mitigate retail cost (cost caps) or transmission reliability impacts. EPA acknowledges that full compliance to date has been challenging with RPS that are much lower that the effective 2020 rates considered in building block 3 by stating that:

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[350] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. pp. 32-33. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

[351] Clean Air Act Section 111(a)(1).

> ...recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008 - 2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[352]

EPA further acknowledges that these less than 100% compliance rates include considerations that are not accommodated by EPA's proposal:

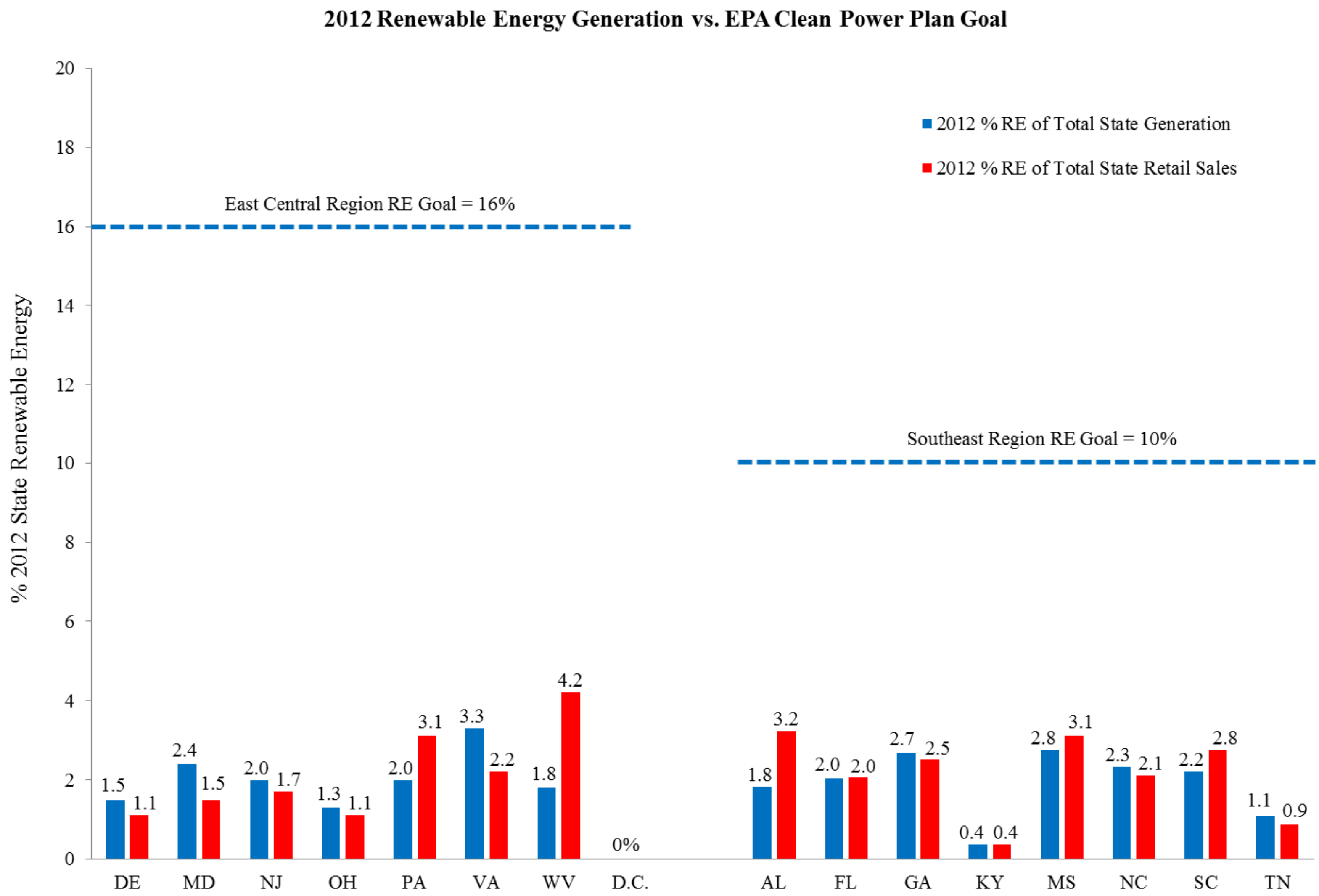
> The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.[353].

Regardless of how the percentage of historic renewable energy is calculated, the regional renewable goals developed by EPA have not been adequately demonstrated. For example, the agency calculated regional goals for the East Central and Southeast regions of 16% and 10%, respectively. However, the maximum renewable energy demonstrated in 2012 by individual states in those regions was 4.2% in the East Central Region and 3.2% in the Southeast Region – ironically, by states that *do not* have mandatory RPS programs. The table and graph below highlight this issue for both regions.[354]

[352] "GHG Abatement Measures TSD." EPA. June 2014. p.4-3.
[353] 79 Fed Reg. 34869
[354] Summary of calculations provided in Appendix C.

| State | EPA Renewable Energy Region | 2012 % RE of Total State Generation[355] | 2012 % RE of Total State Retail Sales[356] | EPA Regional Renewable Energy Target |
|---|---|---|---|---|
| Delaware | East Central | 1.5% | 1.1% | 16% |
| Maryland | East Central | 2.4% | 1.5% | 16% |
| New Jersey | East Central | 2.0% | 1.7% | 16% |
| Ohio | East Central | 1.3% | 1.1% | 16% |
| Pennsylvania | East Central | 2.0% | 3.1% | 16% |
| Virginia | East Central | 3.3% | 2.2% | 16% |
| West Virginia | East Central | 1.8% | 4.2% | 16% |
| D.C. | East Central | 0.0% | 0.0% | 16% |
| | | | | |
| Alabama | Southeast | 1.8% | 3.2% | 10% |
| Florida | Southeast | 2.0% | 2.0% | 10% |
| Georgia | Southeast | 2.7% | 2.5% | 10% |
| Kentucky | Southeast | 0.4% | 0.4% | 10% |
| Mississippi | Southeast | 2.8% | 3.1% | 10% |
| North Carolina | Southeast | 2.3% | 2.1% | 10% |
| South Carolina | Southeast | 2.2% | 2.8% | 10% |
| Tennessee | Southeast | 1.1% | 0.9% | 10% |

[355] Calculated using 2012 Renewable Energy Generation divided by 2012 Total State Generation (both values per "GHG Abatement Measures TSD." EPA. June 2014. Table 4-1)
[356] Calculated using 2012 Renewable Energy Generation (per "GHG Abatement Measures TSD." EPA. June 2014. Table 4-1) divided by 2012 Total State Retail Sales (2012 EIA 861 Report).



2012 Renewable Energy Generation vs. EPA Clean Power Plan Goal
% 2012 State Renewable Energy
20
18
16
14
12
10
8
6
4
2
0
2012 % RE of Total State Generation
2012 % RE of Total State Retail Sales
East Central Region RE Goal = 16%
Southeast Region RE Goal = 10%
1.5
1.1
2.4
1.5
2.0
1.7
1.3
1.1
2.0
3.1
3.3
2.2
1.8
4.2
0%
1.8
3.2
2.0
2.0
2.7
2.5
0.4
0.4
2.8
3.1
2.3
2.1
2.2
2.8
1.1
0.9
DE
MD
NJ
OH
PA
VA
WV
D.C.
AL
FL
GA
KY
MS
NC
SC
TN

The Virginia State Corporation Commission also expressed concern that the regional renewable goals proposed by EPA had not been adequately demonstrated by noting that:

> Another fundamental problem with EPA's addition of future renewable generation into the calculation for Virginia's Mandatory Goals is that it does not establish what has been adequately demonstrated in Virginia, as required by the plain text of the Clean Air Act. For the eight States in the "East Central" region in which EPA places Virginia, EPA's data shows that the renewable generation in 2012 ranged between 1 to 3%, with Virginia at 3% for that year. This is the level of renewable generation that has been adequately demonstrated in Virginia. That other States have future legislative requirements – and no assurance that they will be met – does not change the reality in Virginia.[357]

The aforementioned concerns regarding the applicability of RPS programs from one state to another, as well as the methodology used to calculate state renewable energy goals are further exacerbated by EPA's arbitrary design of six regions in building block 3. In defining these regions, EPA incorrectly assumed that what may be achievable, but not yet demonstrated, in terms of renewable energy development and generation in some states (with the aid of subsidies from the Federal Production Tax Credit and from the investment of out-of-state utilities and customers) is achievable by all states within each respective region. EPA assumes that:

> States within each region exhibit similar profiles of RE potential or have similar levels of renewable resources[358]

However, EPA's rationale is not supported by the technical information referenced by the agency in the proposed rule or by the consideration of RPS in the regional calculations. Examples of conflict between EPA's characterization of individual state RPS and the technical data used to support EPA's proposal are provided below for the South Central, Southeast, and East Central renewable energy regions. In each region, an objective assessment of the existing state standards and technical data evaluating resource availability and cost would result in much lower targets than those established in EPA's guideline.

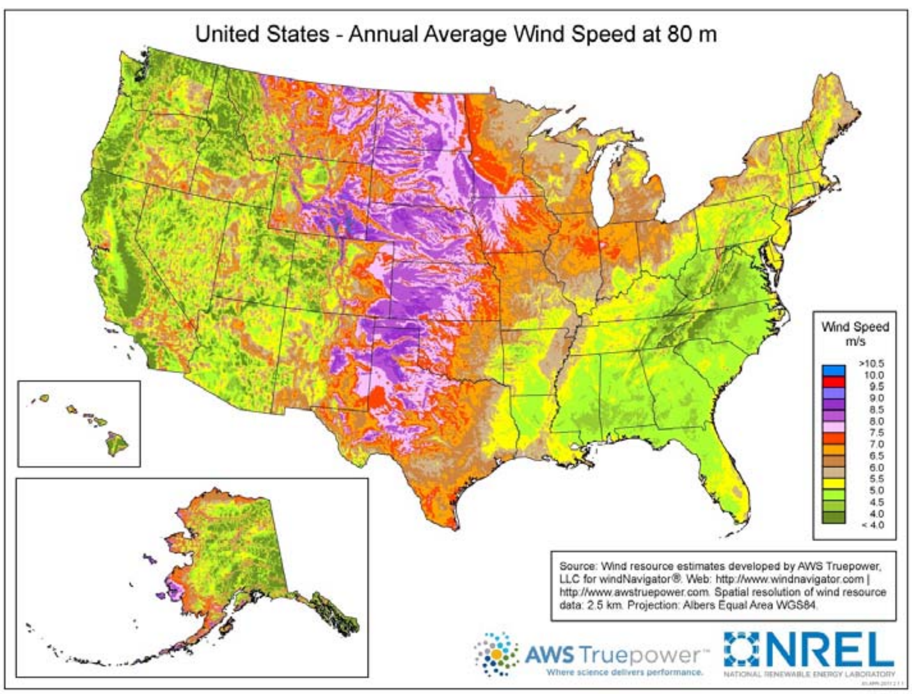
South Central Region

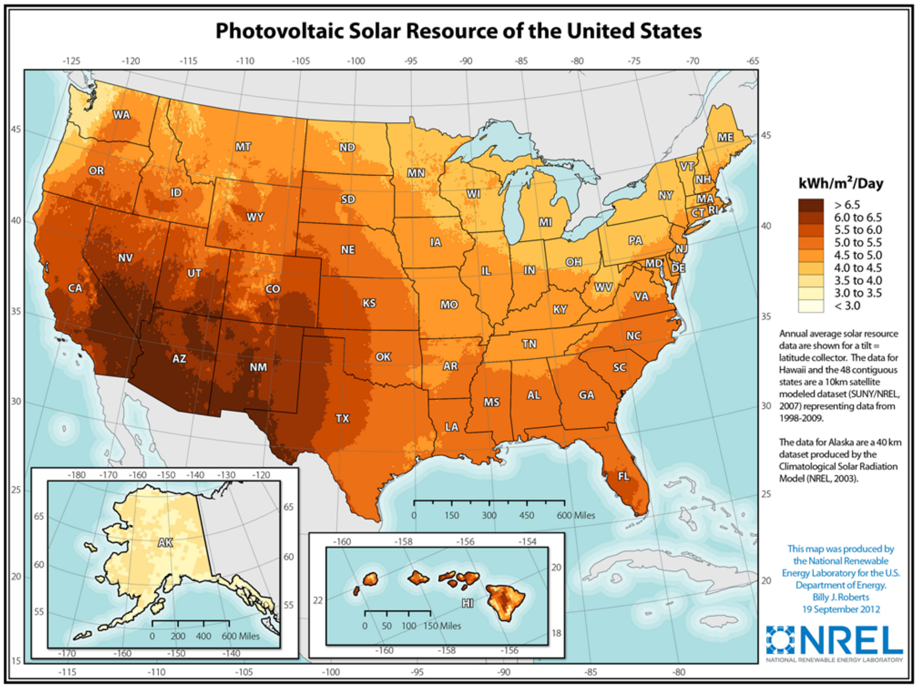
The South Central region is comprised of six states: Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, and Texas. The region is not homogenous in terms of potential renewable resources as four states have far superior resource potential, greater access, and lower cost

[357] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. p.33. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767
[358] "GHG Abatement Measures TSD." EPA. June 2014. p.4-12.

renewable development options. As a result, the remaining two states (Arkansas and Louisiana) are unfairly and inappropriately penalized and burdened with unrealistic goals that cannot be cost-effectively achieved through the development of in-state resources. To achieve their goals most cost-effectively, these states would have to rely on the development of out-of-state resources without certainty regarding if or how such projects would be treated by the host states.

In terms of differences in renewable resource potential, consider the average wind speed or solar resource across the region, a key variable in evaluating the feasibility of wind energy developments, and the availability of potential solar resources. The figures that follow from the U.S. Department of Energy National Renewable Energy Laboratory indicate that there is significant variability across the U.S. and within the South Central region, which indicates significant differences in the opportunities for developing wind energy and solar resources. Arkansas and Louisiana bear a far closer visual resemblance to the states in the Southeast region (Alabama, Florida, Georgia, Kentucky, Mississippi, Tennessee and the Carolinas) than they do to the states in the South Central region.






In addition, while EPA claims to have based its determination of "achievable" state goals based on average values for existing state programs, only one state in the EPA-defined South Central region, Kansas, has a mandatory RPS that was considered by EPA. Therefore, the Kansas RPS – and only the Kansas RPS – is the sole basis for determining the renewable energy goal for all states in the South Central region, regardless of differences in the geographic potential or cost-effectiveness for achieving such a goal among states in the region. EPA also gave no consideration to provisions within the Kansas RPS, such as implementation of cost mitigation measures and in-state renewable credit multipliers, that reduce the overall stringency of the program. As the Kansas Corporation Commission notes:

> Kansas' standard differs from other state's renewable portfolio standards in that <u>it is based on gross generation capacity rather than total retail sales</u>. In general, the gross generation capacity is the amount owned or leased by a utility minus the auxiliary power used to operate the facility.[359]

Based on EPA's own statement that it "*did not* [intend] *to include* [RPS] *targets that were capacity-based*," the Kansas RPS *should not* have been considered in determining the renewable energy goal for the region, and the South Central region would have no qualifying RPS upon which to base a regional goal.

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[359] http://kcc.ks.gov/energy/res.htm (accessed 11/03/14).

Southeast Region

Similar to concerns identified for the South Central region, the calculation of the regional renewable energy goal for the Southeast region relies on the RPS of only one state – North Carolina. Thus, the North Carolina RPS – and only the North Carolina RPS – is the sole basis for determining the renewable energy goal for all states in the Southeast region, regardless of the unique design aspects of the North Carolina program or different geographic potential or cost-effectiveness for achieving such a goal among states in the region. The North Carolina RPS contains a number of unique elements that significantly affect the extent and types of specific renewable resources that may be applicable to other states in the region. Examples of these unique provisions include the following:

- Up to 40% of the standard can be met through energy efficiency measures;
- Up to 25% of the standard can be met by using out-of-state renewable credits; and
- ~10% of the standard *must be* met by energy recovery from swine and poultry waste.[360]

In fact, the U.S. Department of Energy's Database of State Incentives for Renewables & Efficiency ("DSIRE") describes the North Carolina standard as follows:

> Due to the combined circumstances that it 1) has fairly stringent per-account cost caps, 2) allows for energy efficiency and conservation measures to comprise 25% of General Requirement compliance through 2021 and 40% thereafter, North Carolina's REPS [Renewable Energy Portfolio Standard] can function in ways similar to an Energy Efficiency Resource Standard (EERS). However, since it does not require specific annual targets for efficiency and demand-side management, it is not formally considered by DSIRE to be an EERS.[361]

By including both energy efficiency measures and renewable resources in a single goal, North Carolina's standard is far different from the goals EPA claims to be establishing for groups of states on a regional basis. And EPA's methodology, which sets both energy efficiency and renewable goals as part of the state goals, effectively ignores the dual role those measures play in North Carolina, and has increased the state's standards.[362] EPA should have adjusted the actual

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[360] www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC09R (accessed 11/03/14).

[361] Id.

[362] To further highlight the flaws of EPA's methodology for determining regional goals, consider Alaska and Hawaii, which are not included in a specific region. Rather their renewable goals are based on the lowest calculated regional goal – in other words the Southeast regional goal derived solely from the North Carolina RPS. Thus, for the state of Hawaii, which has vastly different geographic and cost-effectiveness considerations, *and* which already has a state RPS with future renewable energy targets of 25% (in 2020) and 40% (in 2030), EPA has proposed a

percentage to reflect this duality, and reduced the renewable portion of the North Carolina and Southeast regional goals.

East Central Region

The East Central region is comprised of Delaware, the District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. Six of the eight states have a mandatory RPS that was used by EPA to calculate the regional and state goals. Even though both Virginia and West Virginia have evaluated renewable energy opportunities and adopted RPS policies, EPA gives no consideration to this experience in calculating the regional goal. Interestingly, the RPS for the District of Columbia is included in the calculation of the regional average, but the District of Columbia had zero renewable generation in 2012, and its standard focuses on the utilization of out-of-state renewable resources as a percentage of sales. EPA has not proposed a state goal for the District, and should have excluded its RPS from the calculation of the East Central regional goal. EPA must also consider the renewable energy experience of Virginia and West Virginia, along with other geographic and cost-effectiveness differences for renewable energy development that exist across the entire region.

The Virginia State Corporation Commission also expressed significant concerns regarding EPA's methodology for developing the state renewable goals by noting that:

> EPA's own data demonstrates why a simple average for calculating a regional target is wrong. The States in EPA's "East Central" region that have higher future RPS requirements are those with relatively little generation compared to the others in this region. Delaware, D.C., Maryland and New Jersey generated approximately 111 million MWh in 2012 and are assigned "2020 Effective RE Levels" between 19 to 22%. In contrast, Pennsylvania, Ohio, Virginia, and West Virginia generated approximately 500 million MWH in 2012 and are either ignored in the calculation or assigned a "2020 Effective RE Level" no greater than 9%. There is no rational basis – legally or mathematically – for giving such undue and unintended influence to certain legislatures at the expense of others, including Virginia.[363]

renewable energy goal that is based on the North Carolina RPS that is premised on the use of out-of-state development, swine and poultry waste, and energy efficiency measures.

[363] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

3. The state renewable goals calculated by EPA are flawed and inconsistent with the assessment and experience of individual states

EPA has ignored details that reduce the stringency of existing RPS, has not considered the renewable energy experience of states without mandatory RPS programs, and has failed to fully consider differences in the availability of potential renewable resources between states. As a result, the agency has derived state renewable energy goals in building block 3 that are technically and cost-effectively flawed, and that are inconsistent with the prior assessment of these resources by individual states.

Prior state experiences are claimed to be strongly valued by EPA in their development and application of renewable energy targets in the calculation of state goals. For example, the agency notes:

> The proposed approach is derived from state experience with policies that drive investment in RE... EPA focused on state-level RE policy... These state-level goals and requirements have been developed and implemented with technical assistance from state-level regulatory agencies and utility commissions such that they *reflect expert assessments of RE technical and economic potential that can be cost-effectively developed for that state's electricity consumers*.[364]

Ironically, EPA ignores these "expert assessments" of state regulators in establishing the renewable energy goals for states that have mandatory RPS or that have previously evaluated potential opportunities for developing renewable resources. A review of the renewable energy goals that EPA used to develop building block 3 reveals that EPA's goals are more stringent than the effective 2020 RPS goals for 14 states, while for 12 of these states the building block 3 goal is less than the RPS target derived from its own expert assessment.

With respect to states that have previously evaluated opportunities to develop renewable resources and decided that a state RPS was currently not feasible and/or economic, EPA has ignored that state experience and applied renewable energy goals that may not be technically or cost-effectively achievable with in-state resources. As an example, Louisiana evaluated opportunities for renewable energy and determined not to implement an RPS program. In 2010, the Louisiana Public Service Commission ("LPSC") approved a Renewable Energy Pilot Program for the state with the goal of determining whether an RPS is suitable for Louisiana. The program ended in 2013 with the LPSC concluding that while the program "was a useful means of

[364] "GHG Abatement Measures TSD." EPA. June 2014. p.4-2. (emphasis added)

gaining valuable information and experience with renewable resources," "a mandatory RPS is not warranted at this time...[because] the levelized cost of renewable technologies exceeds the cost of conventional resources."[365] Despite this experience and these conclusions from the LPSC, EPA utilizes as 20% renewable energy target in calculating the proposed state goal for Louisiana. Ironically, but consistent with the findings of the LPSC, EPA's Alternative Approach found that the technical potential for additional renewable energy in Louisiana is very small, and that even when modeled with a $30/MWh advantage over other available resources, no new renewable capacity would be added in Louisiana by 2030.

The Commonwealth of Virginia has also considered opportunities for renewable energy development, but has not established a mandatory RPS program. The Virginia State Corporation Commission ("VSCC") has expressed concern that EPA did not consider this experience in establishing the renewable energy goals for Virginia, by noting:

> The renewable levels assigned to Virginia are the highest in the East Central region. Thus, even though EPA relies on the legislative determinations of States with renewable requirements to determine what is achievable across a region, the final result of EPA's calculation is that States with such requirements are actually expected to achieve less than Virginia, which has no renewable requirement. In fact, for the States with renewable requirements, EPA's formula sets renewable levels for those States that are lower than the figures built into the regional target that was then applied to Virginia*"*

and

> The results of EPA's formula are illogical: Virginia is expected to achieve renewable levels that are calculated based on other States renewable requirements that the EPA's formula does not ultimately expect those States to achieve.[366]

The state of Arkansas is another example of one that does not have a mandatory RPS, and for which EPA has applied a renewable energy target in the state goal calculation that is premised on the standards established for the state of Kansas that has superior potential renewable resources that could be developed more cost-effectively. The renewable energy target applied to Arkansas in building block 3 is one example of the absurd results produced by EPA's flawed methodology. EPA includes Arkansas in the South Central region, which EPA determined has a 20% renewable energy target and annual growth rate of renewable resources of

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[365] General Order of the Louisiana Public Service Commission for Docket No. R-28271 Subdocket B. Aug 21, 2013. pp.2-3.

[366] Comments submitted by the Virginia State Corporation Commission on the proposed Clean Power Plan." Submitted Oct. 14, 2014. pp.34-35. EPA Docket ID Number: EPA-HQ-OAR-2013-0602-20767

8.3%.[367] If Arkansas would have instead been included in the Southeast region (that has a lower regional target of 10%), one would expect that Arkansas would have a lower renewable energy goal. However, the Southeast region has a lower baseline level of renewable generation relative to its regional target, which translates into an annual renewable energy growth rate for states in the region of 13.4%.[368] Thus, in this example, Arkansas would move to a region with a lower renewable energy target (from 20% to 10%), but would have a more stringent renewable energy growth rate (from 8.3% to 13.4%) leading to a higher 2030 renewable energy goal.

Another example of the absurd outcomes from EPA's flawed methodology is that the required expansion of renewable energy resources does not necessarily occur in the states with the most abundant renewable resources and the most cost-effective opportunities. For example, in the South Central region, the state of Kansas has the second largest amount of renewable energy potential in the region, but increases their renewable energy generation by the lowest amount of any state in the region.[369] Meanwhile, states such as Arkansas and Louisiana, with the least abundant and more expensive renewable energy resources, are required to increase their renewable energy development and generation the most. In fact, EPA's goal calculations assume that only 0.03% of the potential generation from renewable resources in Kansas would be developed, with no additional increases occurring after 2023. Further, despite the fact that Louisiana has only 16% of the potential renewable resources of Kansas, EPA's goal presumes that Louisiana would increase its annual renewable generation by 830 GWh more than the increase assumed for Kansas. Below is a summary these issues for the South Central region.

[367] "Data File: Proposed Renewable Energy (RE) Approach (XLS)." EPA. June 2014. www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-approach.xlsx
[368] Id.
[369] "Alternative Renewable Energy (RE) Approach TSD." EPA. June 2014. p.20.

| | NREL Renewable Technical Potential[370] | **2012** Renewable In-State Generation[371] | 2029 Existing & Incremental Renewables[372] | % 2012 Renewables of Potential Renewables | % Final Goal of Potential Renewables | 2012 to 2029 Increase in Renewables | 2012 to 2029 Increase in Renewables |
|---|---|---|---|---|---|---|---|
| | GWh | GWh | GWh | % | % | GWh | % |
| AR | 5,038,242 | 1,698 | 4,709 | 0.03% | 0.09% | 3,011 | 177% |
| KS | 25,607,687 | 5,253 | 8,885 | 0.02% | 0.03% | 3,632 | 69% |
| LA | 4,171,209 | 2,430 | 6,892 | 0.06% | 0.17% | 4,462 | 184% |
| NE | 17,137,893 | 1,347 | 3,819 | 0.01% | 0.02% | 2,473 | 184% |
| OK | 15,981,649 | 8,521 | 15,579 | 0.05% | 0.10% | 7,059 | 83% |
| TX | 67,627,415 | 34,017 | 85,963 | 0.05% | 0.13% | 51,946 | 153% |

4. EPA should utilize more robust data as the baseline for building block 3

EPA used 2012 data as a baseline to establish individual state goals in building block 3. But a single year can be an anomaly, and EPA should have used a more robust set of data in calculating its goals. Increased generation from renewable resources coupled with changes in the total generation produced in 2013 and 2014 impact both the regional growth factor calculated by EPA and the resulting individual state renewable goals. Using 2013 generation data would decrease the regional renewable energy growth rate calculated by EPA. The table below summarizes this decrease for three regions as an example:

| | Renewable Generation Growth Rate Based on 2012 Data | Renewable Generation Growth Rate Based on 2013 Data[373] |
|---|---|---|
| East Central | 17.3% | 15.9% |
| South Central | 8.3% | 6.8% |
| Southeast | 13.4% | 12.9% |

The change in the growth rate using 2013 data can have a significant impact on the renewable energy goal that EPA calculates for state goals. For instance, utilizing 2013 data reduces the interim and final renewable energy goals for Arkansas by 15% and 22% respectively. Likewise, for Louisiana the interim and final renewable energy goals are reduced by 10% and

[370] "Alternative Renewable Energy (RE) Approach TSD." EPA. June 2014. p.20.
[371] "Data File: Proposed Renewable Energy (RE) Approach (XLS)." EPA. June 2014. www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-approach.xlsx
[372] Id.
[373] See Appendix C for detailed calculations.

17% if using 2013 as a baseline.[374] EPA's selection of 2012 as the single baseline year in its goal calculation efforts is unreasonable and arbitrary.

### C. EPA's alternative approach for calculating renewable energy goals is fundamentally flawed

The proposed alternative approach for calculating renewable energy goals is based on an evaluation of the technical and market potential of renewable resource development in each state. The lower of these two projections forms the basis for developing the state-specific renewable goals. EPA's methodology and the results of its analysis are fundamentally flawed in that they are premised on incomplete, unsubstantiated assumptions regarding the rate at which states can develop renewable resources and the future costs of those technologies.

#### 1. EPA overstates the technical potential of state renewable resources and calculates growth rates for renewable energy development that are flawed

EPA attempts to determine the technical potential of state renewable resources by relying on a 2012 NREL report. This report by design only represents resource potential, with some caveats. However, as the report notes:

> The estimates do not consider...economic or market constraints, and therefore do not represent a level of renewable generation that might actually be deployed.[375]

The report indicates that these "economic or market constraints" include technology and fuel costs, policy considerations, regulatory limits, and regional competition with other energy sources.[376] EPA also acknowledges the significant limitations of this study by stating:

> technical potential data is typically unconstrained by grid limitations, costs associated with development, quality of resource, and may overstate electricity production potential because a given site cannot produce RE simultaneously from multiple technology types.[377]

Other factors that impact the amount of the technical potential resources that can actually be developed include seasonal impacts, transmission considerations, state regulatory processes, and project siting rules and limitations associated with certain endangered species and other environmental programs. Clearly, these issues present technical, cost, regulatory, and practical

[374] Id.
[375] "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis." NREL. July 2012. p. iv.
[376] Id. p.1.
[377] "Alternative RE Approach TSD." EPA. June 2014. p.2

challenges that can and do limit actual opportunities for developing these potential resources. Yet, EPA did not consider these factors in deriving the technical potential or assumed development rate for each resource.

Based on the technical potential of state renewable resources, EPA calculated the level of renewable energy development on a state- and renewable energy-specific basis using the amount of renewable generation produced in 2012. The agency then calculated a benchmark development rate for each renewable technology based on the arbitrary average of the top 16 states for each resource. The benchmark rates from this limited number of states are then incorrectly applied to all states.

EPA's approach is fatally flawed as the agency incorrectly assumes that the technical potential and experience of 16 states is sufficient for establishing renewable energy goals for all other states. EPA's reliance on historic renewable energy development in only the top 16 states disregards the fact that experience of these limited states may not be applicable or achievable by other states, as the top performing states are typically those with the greatest renewable generation potential, greatest access to transmission, and have lower development costs. In addition, EPA made no attempt to evaluate the quality of the resources developed, the manner in which they were funded (out-of-state entities, federal tax credits, grants, etc.), or other drivers for development that may not be applicable to other states. Given that subsidies such as the federal production tax credit and investment tax credit have already expired or are scheduled to expire before the states even file their compliance plans, it is not reasonable to expect that past development of renewable resources is necessarily indicative of future development potential as experienced in recent years when these tax benefits were available. Further, EPA did not consider whether existing renewable resources represent opportunistic or nuanced circumstances for development that cannot be readily replicated or expanded.

The NREL report acknowledges these state differences by estimating potential renewable resources based on varying assumptions on the capacity factors that would be expected from each technology. For example, NREL provides state-specific estimates of capacity factors for photovoltaic resources. For the states in the EPA-defined South Central region, the capacity factors for photovoltaic resources ranged from 19.6% (Louisiana) to 23.8% (Kansas). Thus, EPA does not consider that the development rates derived from the top performing states may not be achievable by other states that are not able to utilize their resources at the same rate due to differences in the availability of the resource.

The agency has provided no rationale for why it is appropriate to assume that the development achieved to date by select states, with different technical, cost, and policy considerations, is replicable and represents what is achievable by all states going forward. Nor has EPA provided any rationale for using prior growth rates as an indication of achievable future growth, particularly given the technical challenges associated with incorporating increased renewable energy into the power supply system, such as the need for additional transmission investment.

2. EPA uses unsubstantiated assumptions on future costs to estimate the market-based potential for state renewable energy development

EPA also used its Integrated Planning Model to evaluate renewable energy development assuming a $30/MWh reduction in the cost of all types of new renewable resources. However, EPA failed to provide any basis that supports this rate of reduction or its broad-brushed applicability to all types of renewable resources. The factors that impact future costs are specific to each resource and must consider technology advances, permitting and regulatory issues, energy market considerations, and the availability or need for transmission updates, among other factors. Further, cost trends for one renewable technology are independent of the trends for other resources, and will vary by location and by the maturity and use of the technology. For example, onshore wind resources in the interior of the country are approximately $35/MWh less expensive than they are in the western U.S.[378] EPA's attempt to apply renewable energy goals that must be achieved by all states based on limited, region-specific data is flawed. Instead, EPA should use state, regional, and technology-specific costs in its modeling approach as opposed to a broad average that is assumed to be achievable by all renewable energy resources, regardless of location and/or the continued availability of federal subsidies for certain renewables.

Further, EPA provides no evidence regarding if, when, or how its assumption that renewable energy technologies, as a whole or individually, would be reduced by $30/MWh could be achieved. Nor does the agency provide any details regarding the baseline cost from which the $30/MWh rate was reduced. The cost of renewable resources is strongly influenced by public

[378] "2013 Wind Technologies Report." U.S. DOE. Aug 2014. http://energy.gov/eere/wind/downloads/2013-wind-technologies-market-report

policies. As the NREL study notes, tax credits greatly influence the development of renewable energy.[379] Lazard, an independent financial advisory and asset management firm, notes the impact of federal subsidies on the levelized cost of energy (LCOE) for renewable technologies in their annual LCOE analysis. The cost reduction due to subsidies varies by technology, but can be as much as $42/MWh on a levelized basis.[380] Given that subsidies such as the federal production tax credit and investment tax credit have already expired or are scheduled to expire before the states even file compliance plans, it is not reasonable to expect costs to continue to decline at the same level as experienced in recent years when these tax benefits were available. In addition, tariffs on imported solar panels[381] and tightening supply may slow the decline in price of solar panels in the near term.[382,383]

The cost of any technology depends on many factors, and EPA provided no information about how these factors were considered in determining that $30/MWh is a reasonable cost reduction estimate. Accordingly, it is not clear that EPA accounted for technology- and region-specific factors and trends. If EPA finalizes its alternate proposed approach, it must provide sufficient data and analysis to justify this number. If no such analysis is available, then EPA must remove the estimate from any calculation of state RE targets altogether. Specifically, EPA should not adjust IPM results by any assumed future subsidies.

3. The alternative methodology produces absurd results as applied to state emission rate goal

By using a combination of an arbitrary renewable cost reduction and integrated modeling process, some states are forecast to have a dramatic increase in renewable energy under the proposal. As two prime examples, Kansas is expected to have a target for renewable energy equivalent to 115% of 2012 generation (excluding hydroelectric sources) by 2029 and South Dakota has a target equal to 159% of 2012 generation. If these numbers were applied to state emission rate goals, this would significantly reduce the $CO_2$ emission rate goal for the states and

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379 Owen Zinaman et al., *ReEDS Modeling of the President's 2020 U.S. Renewable Electricity Generation Goal* at 12 (May 2014)

380 Lazard, *Levelized Cost of Energy Analysis (*Sept. 2014),

381 U.S. Department of Commerce, *Commerce Preliminarily Finds Counteravailable Subsidization of Imports of Certain Crystalline Silicon Photovoltaic Products from the People's Republic of China* (June 2014)

382 Munsell. M., *New Tariffs on Chinese Solar Modules Will Raise US Prices by 14%, GREENTECHSOLAR* (June 20, 2014).

383 Press Release, IHS, US to Dodge Shortage This Year Even Amidst Fines on Chinese Module Suppliers. Apr. 17, 2014

likely force out any fossil resources necessary to provide firm energy to support this level of renewable development. Furthermore, as this level of renewable energy would be in excess of in-state needs, these states would be legally required to produce emissions reductions that could only be achieved by extreme penetration of renewable energy without any requirement that other states share the cost burden. This would subject in-state ratepayers to the potential for enormous cost increases while other states would likely see displacement of fossil resources at no cost. This illustrates that this alternative methodology creates significant winners and losers at the state level by parsing state-based results from an integrated national model.

### D. Building Block 3 Comments related to EPA's NODA

1. The alternative approach proposed in NODA is flawed

EPA requested comment on a regional approach to defining state renewable energy target levels. This approach would allow EPA to establish regional targets for renewable energy and apportion out requirements to individual states based on a state's share of regional retail sales or generation. This approach is substantially flawed for a number of reasons. First, this approach could effectively force states to rely upon generation resources outside their boundaries and, beyond their jurisdiction, making compliance subject to a multitude of factors outside of state control. Second, utilizing a regional approach as applied to just this building block is highly arbitrary. While arguably all of the other building blocks have regional attributes to their application, none of the other building blocks were examined or calculated within a similar regional context, presumably based on the fact that states are required to develop and implement these programs by statute. Third, any use of regions that do not correspond to small and distinct electric transmission control areas would ignore significant transmission constraints that must be addressed in order to accommodate regional renewable development. It seems that EPA is contemplating a much broader definition of "region." Fourth, EPA has not provided any clear guidance within the proposal regarding how renewable credits could be treated within a rate-based compliance approach given differences between the states' goals, nor would this approach be facilitated by using a mass-based compliance program as out-of-state resources might not displace in-state emissions. Absent clear guidance on interstate issues, EPA's identification of this alternative in the NODA provides no basis for informed comments.

The final and most serious concern related to the alternative process based on regional renewable targets is that the outcomes for individual states are not reflected in any definitive way. The only other proposals from EPA are the primary and alternative calculations of renewable energy goals associated with the initial proposal. Both of those methodologies are deeply flawed. Applying a variation of that same flawed analysis to a broader region, and then using an unidentified process for allocating individual state responsibilities under this option, would be arbitrary and capricious, and has no foundation in the materials placed in the record for this rulemaking.

2. State Goal Calculation Method for Building Block 3 and 4.

EPA requested comment on whether the goal-setting calculation should "back-off" fossil generation in response to the addition of the renewable energy and energy efficiency building blocks. AEP strongly disagrees with this modification as this change would artificially place additional emission reductions on many states and thus result in further stress to the electrical system. While renewable energy and energy efficiency have some implications for the utilization of existing sources they also play a key role in offsetting the need for new generating sources, and thus a determination that these building blocks would solely displace existing fossil generation is not practical.

EPA has not attempted to evaluate how such an approach would affect the operation and reliability of the grid as *dispatchable* fossil resources are needed to support voltage, frequency, capacity needs and enable renewable technologies to be deployed. Under the proposed revision to the state goal calculation, some states (e.g. Washington, Idaho, Oregon, Maine) would be left with *zero* fossil fuel-based generation, which significantly impairs the ability of operators to maintain reliability. If this proposal was expanded further as contemplated within the NODA, and building blocks 3 and 4 were applied to reduce fossil-steam generation preferentially, such as is done with building block 2, all fossil-steam generation would be lost in 21 states - even while existing NGCC capacity would be assumed to run at a fixed capacity factor. EPA has not performed any analysis to suggest that the grid could function without these critical capacity resources. As such, this potential alternative goal calculation approach should be rejected.

### E. EPA did not fully consider transmission issues that impact the feasibility, cost, and timing for developing additional renewable resources

As discussed in the comments below on reliability, the increased development and utilization of renewable energy resources introduces a number of concerns regarding the need to upgrade and/or expand the existing grid. The concerns become more significant when coupled with the impact of all the building blocks on the grid in terms of changes to the location and capabilities of generation versus load centers. NERC has identified a number of issues that must be addressed in order to accommodate the increased development of renewable resources. For example, NERC's 2013 Long-Term Reliability Assessment notes that:

> Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro)...will require significant changes to traditional methods used for system planning and operation... Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS [bulk power system] reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability.
>
> Accommodating higher levels of variable resources requires cooperation and coordination within each interconnection—especially between BPS and non-BPS entities. Frequency stability, frequency response, energy imbalance, and increased and dynamic transfers must be addressed at all levels. Specifically, increasing amounts of solar photovoltaic (PV) generation leads to decreased system inertia and frequency response capabilities that could potentially result in reliability impacts on the BPS.
>
> Wind generation is often located substantial distances from the point of interconnection to the transmission system, which creates additional reliability implications. In many cases, the location of these variable resources only meets the minimum voltage support requirements.
>
> The addition of significant amounts of variable generation to the BPS changes the way that transmission and resource planners develop their future systems to maintain reliability.[384]

EPA has not seriously considered any of these technology, economic, and regulatory challenges related to integrating additional renewable generation into the interconnected power supply system. However, these issues introduce significant uncertainty regarding the feasibility, cost, and timing of increasing renewable resources.

[384] 2013 Long-Term Reliability Assessment. NERC. Dec 2013. pp. 22-24.

### F. EPA does not fully consider the technical, cost, regulatory, and practical challenges of increasing renewable resources

A number of state-specific factors impact not only the amount of potential renewable resources available, but also impact the feasibility and rate at which such resources may be developed. These factors include geography, topology, energy markets, seasonal differences, transmission considerations, state regulatory processes, and project siting rules associated with certain endangered species and other environmental programs. A summary of the development challenges that EPA must consider follows below:

<u>Implementation</u>

As discussed in the comments that follow related to implementation, generation (and related transmission) planning involves input and decisions from a number of entities, such as various state regulators, regional transmission organizations, and independent system operators. As proposed, the state goals are based on states increasing renewable generation beginning in 2017 – the earliest date that a state would have a final, approved compliance plan, and before regional plans would be submitted to EPA for approval. As such, the proposal would not allow sufficient time for the design, approval, and implementation of state and/or regional compliance strategies needed to achieve the proposed renewable energy goals. The implementation comments also discuss significant concerns and uncertainties pertaining to the mechanics of implementing and managing interstate issues associated with how states that support the development of out-of-state renewable resources obtain credit for such resources in their compliance plans.

<u>Regulatory Considerations</u>

EPA did not evaluate the impact of regulatory processes on the timing and feasibility of developing renewable energy resources. Timing related challenges are introduced by the number of regulatory agencies that must evaluate and approve the addition of renewable resources, including the necessary arrangements to connect those new generating resources to the grid, as well as by the number of agencies that evaluate and balance the impacts of multiple projects across multiple jurisdictions. This includes agencies whose obligations are very diverse, including cultural and historic resource agencies, marine, fish and wildlife services, aviation authorities, state and federal land management agencies, and others.

### G. EPA should exclude nuclear energy from state goal calculations

Nuclear energy should be excluded from the state goal calculations, but should remain an option for states to consider in developing their state plans to meet the proposed goals. Consideration of at-risk and new nuclear generation unnecessarily introduces uncertainty into the goal setting methodology and compliance planning due to concerns regarding the short- and long-term viability of EPA's assumptions regarding the continued operation of the existing nuclear fleet and with respect to if/when the under construction nuclear capacity actually is commissioned. The implementation section identifies additional concerns for developing compliance requirements for nuclear capacity within state plans that further warrant excluding nuclear energy from the goal calculation.

### H. Recommendations regarding building block 3.

In summary, renewable energy and nuclear energy should not play any role in establishing the BSER for existing fossil fuel fired electric generating units. If EPA decides to allow states to introduce additional flexibility in achieving broad state goals through measures considered in this building block, then the inclusion of renewable energy in calculating the state plans should be based on the state-specific technical potential and cost-effectiveness of renewable resources, and state-specific growth factors that take into account all of the issues identified in this section. Such considerations might minimize or eliminate this component for many states and especially those states that have already evaluated and determined that opportunities for renewable energy development are limited. In order to fully assess the feasibility and potential costs of implementing the types of renewable goals envisioned in the proposed rule, more information is needed regarding:

- the final level of renewable energy to be considered in establishing the state goal;
- the mechanisms available to resolve interstate issues regarding the "credit" for renewables procured in one state for the benefit of customers in other states;
- the mechanisms that will be acceptable to the states and EPA for purposes of demonstrating compliance; and
- the location, size, and design of new renewable capacity must be known to adequately evaluate the cost of transmission improvements necessary to support those facilities and to assess whether additional generation resources are needed during periods when the renewable resources are not available.

## VIII. Building Block 4 Comments

As discussed above, EPA does not have the authority to consider energy efficiency ("EE") measures adopted by customers when determining the BSER.[385] In addition, EPA has failed to demonstrate that the EE standard is achievable or has been adequately demonstrated. Specifically, EPA ignores the expert evaluations of the majority of states regarding a reasonably achievable level of EE, the pace of increase in EE achievement, and a reasonable level of costs to achieve those proposed EE levels. Further, the data and methodology that the agency used in establishing these levels for all states in a one-size-fits-all manner ignores many fundamental differences between the states that affect the nature and scope of achievable EE measures and rates of growth. EPA did not use a transparent process in estimating the costs of the proposed EE levels, did not consider all cost elements of EE, and did not give adequate consideration to the effect of such costs on customers. EPA's failure to specifically identify the evaluation, measurement and validation ("EM&V") methods required for a satisfactory state plan, and its failure to assess whether such EM&V measures are currently applied in the programs identified as "best practice standards," provide an inadequate basis for commenters to determine the actual impact of the proposed guidelines. Accordingly, EPA should withdraw this aspect of the proposed guidelines.

To the extent that EPA allows states to rely on EE measures to satisfy a portion of their obligations in any state plan, EPA should give deference to the states' determination of a reasonable level of EE achievement considering the costs, non-air environmental impacts, and other factors outlined in section 111(d). Each state could then use that level of EE potential as it deems appropriate. If, however, EPA retains EE as part of the portfolio of options to be considered by the states, it should re-evaluate the stringency of the portion of the state goals based on such measures in accordance with the following comments.

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[385] Indeed, in the context of EPA's authority under section 169 of the CAA to specify what is the "best available technology" for regulated pollutants in a new source review ("NSR") permit, the Supreme Court noted with approval that, "BACT may not be used to require 'reductions in a facility's demand for energy from the electric grid,'" and that "BACT should not require every conceivable change that could result in minor improvements in energy efficiency, such as the aforementioned light bulbs." Rather, the Court confirmed that BACT can only be required for pollutants that the source itself emits, and that permitting authorities should consider whether the proposed regulatory burden outweighs any emission reductions that can be achieved. *UARG v. EPA,* 134 S.Ct. at 2448.. These same principles should apply to the BSER, which, as demonstrated above, is based on technology that can be applied to emission from the regulated source, and must satisfy the statutory balancing of costs, other environmental affects, and the emission reductions actually achieved.

### A. Flaws in EPA's EE Achievability Analysis

There are several flaws in the analysis used by EPA to establish the level of EE measures to be used in the calculation of state goals. The cumulative effect of these flaws is that EPA has substantially overstated the amount of EE that could be achieved by states

#### 1. Base data inconsistencies

The source of the base data that EPA relied upon for EE achievement data is not reliable. EPA uses EIA Form 861 data as the baseline level of the amount of EE achievements by utility EE programs. EPA acknowledges the consistency and quality issues with EIA Form 861 data, as utilities rely upon differing methodologies in measuring the net impact of their EE programs; however EPA does not fundamentally address this issue.

#### 2. Invalid extrapolations

Extrapolation of EE achievement levels between states results in invalid comparisons. EPA suggests that a certain level of EE can be achieved by all states based on its evaluation of "best practices" achieved in certain states. The assertion that the experience in these states can be easily replicated in others is based on simplistic assumptions, not detailed analyses. There are fundamental flaws in such extrapolations when inherent real-world differences among the states are properly considered.

##### a. Relative size of customer classes not comparable

The relative size of the different classes of customers (industrial, commercial, and residential) is substantially different between states and across utility service territories; and the relative potential and costs to achieve EE savings across these customer classes varies substantially. Many states (such as those in the Midwest) deliver a much higher percentage of their electricity to industrial and manufacturing facilities. Others (such as those in the Northeast) have a much larger percentage of commercial and service-based entities in their customer mix. States with higher industrial and manufacturing activity tend to have higher overall electricity consumption levels. Because the EE target levels are based on total retail sales, this increases the EE target levels as well. In addition, implementing utility-sponsored EE at these industrial and manufacturing facilities can be much more challenging and costly, as they tend to be facility-specific measures that are based on unique circumstances, such as replacing pumps, motors, and drives in manufacturing equipment with more efficient models.

b. Commercial and industrial opt-out provisions not considered

Many states have determined that larger commercial and industrial customers should be not be required to participate in the utility-sponsored EE programs, because these customers typically have the sophistication and resources available to implement their own EE measures, have better access to capital, and better rates, and are generally better informed as to their EE options. In these instances, EPA should exclude commercial and industrial sales, or allow the requirement for EE implementation to be placed directly on those customers. In any event, as discussed above, the expected penetration rate for required EE programs should be consistent with the base of sales that can be addressed by those programs.

c. Customers subject to section 111 of the CAA should be excluded.

Certain industrial customers are also in industrial categories that are themselves subject to standards of performance under section 111 of the CAA, including steel, glass, paper, and chemical manufacturing, refineries, and other industries. For such customers, requiring efficiency improvements under an electric utility standard is not justified, when additional requirements may be imposed as part of a future section 111 standard for their source category. To the extent that any portion of the state goals is based on customer end use efficiency measures, the degree of manufacturing and industrial load that forms a part of the customer base must be considered, and appropriate adjustments made to exclude all or at least the portion of such load that is subject to a separate section 111 standard.

d. Average temperatures and electricity consuming devices are not comparable

The average temperatures and relative use patterns for specific electricity consuming devices among many of the states used to define "best practice" for EE are fundamentally different from the average temperatures and use patterns in other states. Foremost among these differences is the significant variation in space heating and cooling requirements and their relative contribution to electricity loads. Space heating and cooling are by far the largest energy-consuming loads in most households and many commercial establishments. EPA's failure to account for these differences leads to a flawed assessment of the percent of EE reductions that can be achieved across different states.

Regarding electricity consumption for space cooling, the differences are stark. For instance, Massachusetts has significantly fewer cooling degree days than Texas.[386] In Massachusetts, electricity used for space cooling accounts for only 1% of average household electricity consumption; over 20% of homes have no air conditioning; the majority of the remainder use smaller window/wall units sparingly; and only 20% having larger central air conditioning units. In contrast, in Texas electricity used for space cooling accounts for 18% of average household electricity consumption; over 80% of homes have central air conditioning; and those units are used much more extensively throughout a longer cooling season. As such, electricity needs for space cooling are significantly higher in Texas than in Massachusetts.

Regarding home heating, there are significant differences as well. Massachusetts experiences significantly more heating degree days than Texas.[387] However, a significant percent of residential heating is met using natural gas (>50%) and fuel oil (31%), while electricity is used very sparingly (10%). In contrast, in Texas electricity provides a significant portion of the energy to meet residential heating needs (50%), with relatively smaller percentages of natural gas usage (~42%) and virtually no heating oil. Therefore, due to a combination of average temperatures and prevalence and type of space heating and cooling equipment, households in Massachusetts rely on electricity significantly less than those in Texas to meet basic space heating and cooling needs of homes.

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[386] US NOAA / National Weather Service: (www.erh.noaa.gov/cle/climate/info/degreedays.html)
Q: What are degree days?
Heating engineers who wanted a way to relate each day's temperatures to the demand for fuel to heat buildings developed the concept of heating degree days.
To calculate the heating degree days for a particular day, find the day's average temperature by adding the day's high and low temperatures and dividing by two. If the number is above 65, there are no heating degree days that day. If the number is less than 65, subtract it from 65 to find the number of heating degree days.
For example, if the day's high temperature is 60 and the low is 40, the average temperature is 50 degrees. 65 minus 50 is 15 heating degree days.
Cooling degree days are also based on the day's average minus 65. They relate the day's temperature to the energy demands of air conditioning. For example, if the day's high is 90 and the day's low is 70, the day's average is 80. 80 minus 65 is 15 cooling degree days
Mean Cooling Degree Days in MA average 100-700, while in southern TX average 2500-3500.
US Dept of the Interior, US Geological Survey. http://nationalmap.gov/small_scale/printable/climatemap.html#list

[387]Mean Heating Degree Days in MA average 6000-9000, while in southern TX average 1000-2000.
US Deprtof the Interior, US Geological Survey. http://nationalmap.gov/small_scale/printable/climatemap.html#list

These phenomena are directly relevant to the issue of EE achievement potential. Lighting has historically been among the most widespread and successful utility-sponsored EE measures. But if the same EE lighting measure (such as a CFL light bulb) is installed in a low-electricity-use household in Massachusetts, it will contribute a far greater percent reduction in electricity usage than that same measure installed in a higher-electricity-use household in Texas. For example, all other things being equal, since household electricity consumption in Massachusetts is only about half that of Texas, the exact same EE measures installed in a typical Massachusetts household that resulted in a 1 percent reduction in electricity consumption would produce only a 0.5 percent reduction in a typical Texas household. If the identical types and levels of EE measures are implemented in a state that has double the energy consumption than another, the impact on a percentage-basis would be half that experienced in the original state.

These stark differences are particularly relevant because what EPA characterizes as EE is a misnomer. When EPA professes that a certain state has achieved a certain percent of energy efficiency, in actuality what is measured is the reduction in electricity consumption relative to the base of all electricity consumption. Other energy sources are completely ignored. For example, though the average household consumes only about one-half the electricity in Massachusetts as it does in Texas, when one compares the *total energy* consumption (on a British thermal unit "BTU" basis) the comparison is completely different. Massachusetts uses 22 percent *more* energy per household than the US national average, while Texas households use 14 percent *less* than the US average.[388]

e. Temporal considerations

In addition to these geographic differences, there are temporal challenges in extrapolating past EE achievements into the future. There has been a significant increase in overall baseline efficiency codes and standards, which will inherently reduce energy consumption irrespective of the impacts of utility-sponsored EE programs. The most significant changes have occurred in lighting EE efficiency standards, which have historically produced the greatest utility-sponsored EE achievements.

U.S. appliance efficiency standards and building codes have become increasingly more stringent. DOE has issued numerous new EE standards over the last few years, which will affect

[388] Source: US Energy Information Administration, Residential Energy Consumption Survey.

energy use as new homes are built and equipped with such appliances, and existing homes undertake replacement of appliances in the ordinary course. For instance, the Department of Energy ("DOE") has proposed new efficiency standards for commercial rooftop air conditioners that would reduce energy consumption by 30 percent, achieving the largest national energy savings of any standard ever issued. Over 30 years, it is estimated that this one standard could produce energy savings equivalent to one-half of all residential energy used in the U.S. in a single year.[389]

For any given EE measure, this increased baseline efficiency results in less EE savings opportunity for administrator/utility-sponsored programs. For instance, with this dramatic increase in efficiency standards for rooftop air conditioners, utility-administered EE achievements in this segment would become significantly more difficult and costly. Commercial customers would be achieving significant savings as a result of the standard, and less receptive to investing in more efficient equipment, as this equipment would come at a premium, but provide only marginally higher EE savings.

The impact of this phenomenon is most acute for lighting standards resulting from Energy Independence and Security Act (EISA) of 2007. Utility-sponsored EE programs have traditionally heavily relied upon lighting programs (most significantly residential CFL, and commercial T-8 fluorescent lighting programs) for a very significant portion of their EE achievements. While specific disaggregated data on program administrator reliance on lighting measures is typically not disclosed, indications are that many residential programs may have relied upon lighting measures for over half of their EE achievements in the past. One study conducted on the subject in the northeastern U.S. indicated that the two EE programs reviewed relied upon lighting for 94% of the EE achievements.[390]

With the adoption of the EISA 2007 lighting standards, standard incandescent bulbs and T-12 commercial lighting fixtures are no longer able to be manufactured or imported into the U.S. Therefore, this large and inexpensive market for utility-sponsored EE savings is being substantially eroded as the baseline efficiency level increases to the new standard. It is

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[389] http://energy.gov/sites/prod/files/2014/09/f18/2104-09-18%20Issuance%20cauc_noticeofproposedrulemaking.pdf.

[390] *Benchmarking of Vermont's 2008 Electric Energy Efficiency Program*s, at p. 10, http://publicservicevermont.gov/sites/psd/files/Topics/Energy_Efficiency/EVT_Performance_Eval/Final%20VT%20BED%20Benchmarking%20Report.pdf

anticipated that by 2020 or soon thereafter, CFL devices will become the standard (or baseline), further limiting future efficiency improvements from these programs.

EPA utilized historic achievements built largely upon these low-cost and readily available EE lighting measures when making its projections for EE savings potential in future years. There are market potential studies that assert plentiful and inexpensive EE savings opportunities available from other EE measures in the future. However, there is no empirical evidence that any utility-sponsored EE programs relying upon these non-lighting measures can achieve EE levels even approaching those levels achieved through lighting programs. In the absence of further evidence of the availability of other programs that can deliver similarly substantial savings, EPA clearly fails in its requirement to demonstrate the technical achievability of its proposed standard under the EE codes and standards currently in effect.

f. Other options

Non-lighting measures have been aggressively pursued by many utilities; however capturing these savings is much more difficult. Non-lighting savings have not been achieved in significant quantities in any state, and most cost substantially more on a per-MWh basis. These measures are primarily comprised of thermal efficiency measures, such as heating, air conditioning, and other appliance efficiency upgrades, and weatherization measures. They are expensive, requiring a relatively large capital investment by customers for new appliances and equipment. This is problematic, as customers customarily avoid such large expenditures until a precipitating event occurs (appliance or equipment failure, etc.). Therefore, utilities would need to offer a much higher incentive payment to encourage customer participation. These are the types of EE measures that will need to be increasingly relied upon to achieve ongoing incremental improvements going forward as dependence on abundant an inexpensive lighting measures declines significantly.

3. Customer economic challenges

Many customers are challenged economically to invest in EE upgrades. AEP anticipates continued difficulty in motivating customers to pay premiums for such EE improvements due to much of its service territory being perpetually economically disadvantaged. AEP-served counties have household incomes that are approximately $9,000 less than the national average. Some of the counties it serves have average household incomes that are less than half the national average. The types of EE achievements proposed by EPA have not been historically demonstrated during a time of significant economic hardship, such as those being currently experienced (and likely to be exacerbated by imposition of the EPA rule) in manufacturing and coal mining dependent areas. When significant near-term economic performance is depressed and unemployment levels are high, customers postpone improvements that are not cost-justified in the short-term. Many customers are not willing or able to pay a premium to achieve a long-term economic benefit through investment in higher efficiency devices. Further, neither EPA, nor the states can force customers to achieve higher levels of EE. It is completely outside their control. EPA acknowledges that there are practical, economic, and market barriers to tracing the effects of EE deployment, but fails to fundamentally address these issues. Without addressing these issues, EPA has not shown that the proposed goals are achievable or adequately demonstrated.

4. Market potential studies

The Market Potential Studies ("MPS") that were relied upon to propose future levels of EE do not provide an adequate basis for use in establishing a regulatory compliance target. Much of the data and information was supplied by EE advocacy organizations and others with a similar focus, and was not subject to a peer review process. EPA notes that nearly all of these studies represent a "top-down, policy-based approach" and do not account for all of the practical factors that are necessary to build functioning EE programs. The metrics adopted by EPA largely comport with these findings, and differ substantially from the "bottom-up," engineering-based analysis that has been conducted on the topic. One study analyzed was conducted by Electric Power Research Institute ("EPRI") in 2014. EPRI's study used a conventional bottom-up engineering approach. As EPRI explains in their study, such an approach is "based on equipment stock turnover and adoption of energy efficiency measures at the technology and end-use levels" at a regional level "yielding detailed, granular results by division, sector, building type, end-use, and technology."[391] Notably, EPRI's estimate for average annual achievable potential EE based upon their engineering approach was 0.5% to 0.6% per year, while the top-

[391] EPRI, U.S. Energy Efficiency Potential Through 2035, p. vi, www.epri.com/abstracts/Pages/ProductAbstract.aspx?Product id=000000000001025477.

down policy approaches estimated EE potential many times higher at approximately 1.5%. Ultimately, EPA chose to use 1.5% as the "best practice level."

The MPS do not prove empirically that these levels of EE are achievable or sustainable. Much like the renewable resource studies referenced in EPA's analysis of alternative methods to develop state renewable energy goals, the MPS are not precise engineering analysis undertakings. Substantial differences in the models, assumptions, data sources, interpretations, etc. by various authors often make significant differences in the results. In a study conducted by the American Council for an Energy-Efficient Economy ("ACEEE"), 45 publicly available market potential studies performed since 2009 were reviewed, and ACEEE found that "for electricity, [the] average annual maximum achievable savings range [was] from 0.3% to 2.9%."[392] That is nearly a 1000% variation, depending on the assumptions and methodologies employed in the study.

There is a significant lack of transparency on major model inputs such as forecasting participation rates, incentive level estimates, impacts of codes and standards, emerging technologies, utility avoided cost estimates, and policy limitations. Even modest deviations from these point-in-time assumptions, estimates and projections, will compound over time and significantly affect the results. This is especially the case with projections made over 15 or more years, as EPA has done. Due to these factors, it is generally understood that MPS are most applicable to and best suited for short-term program planning rather than long-term policy application. EPA itself acknowledges the substantial variation in potential estimates, driven by lack of broad empirical evidence and significantly varying assumptions and methodologies. Regardless, EPA ignored these limitations, and instead proposed to set legally enforceable requirements based upon such studies. EPA must re-evaluate the basis for its proposed goals, and examine the full range of studies that have been performed, rather than selecting the highest projected rates and applying them indiscriminately across the country.

5. States used as proxies

The states used to demonstrate achievable EE levels are not representative of the varying experiences in other states. EPA used a set of top 12 states in terms of EE performance as

[392] ACEEE, *Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies, page v.*

measured by incremental savings as a percentage of retail sales (based on the 2012 reported data). EPA concluded that three states (Arizona, Maine, Vermont) have already achieved the highest level of performance, more than 1.5 percent annual incremental retail sales saving. Previous comments demonstrate the incomparability of these states to others as a whole. EPA notes that nine other states have EE policies in place that will bring their annual incremental savings levels to the 1.5 percent rate by 2020.[393] EPA cannot rely on speculative future EE targets as evidence that certain levels of EE are achievable or sustainable. Further, EPA ignored that two states they cited (both of which AEP serves, Indiana and Ohio) have recently taken legislative action to reconsider the degree of achievability of their long-term targeted EE requirements. Part of the reason for their concern is the potential rate impact that these programs are having on retail customers. Further, EPA asserts that states can sustain a level of 1.5% of incremental EE achievements indefinitely. EPA offers no justification for this assertion, and in fact there is no evidence of any program sustaining this level of EE achievement over the length of time covered by the proposed rule.

6. Illustrated example

One way to demonstrate the unachievable nature of the proposed rule is to review the participation levels and energy reductions that would be required. A 1.5 percent of retail sales EE achievement requires some combination of participation rate and savings rate, such that EE target = % participation x % reduction. Therefore, a 1.5 percent reduction equals:

- 10 percent participation with 15 percent savings, or
- 15 percent participation and 10 percent savings, or
- 2 percent participation with 30 percent savings, etc.

If an EE measure is targeted to replace older heat pumps with one that is 30 percent more efficient, and this would result in an overall reduction in household consumption by 10 percent, a utility would need 15 percent of its *entire* customer base to participate in the heat pump replacement program *every year* to meet the standard. But even if *all* customers had heat pumps, and they are replaced at failure every 15 years, only 6.7 percent of the total customer base would be in the market for an upgrade in any given year. Many utility-sponsored EE programs produce

[393] These nine other states are Colorado, Illinois, Indiana, Massachusetts, Minnesota, New York, Ohio, Rhode Island and Washington.

much lower efficiency gains. The higher efficiency gains like heat pump replacements are also accompanied by requirements for relatively high customer costs. Therefore, customer participation rates in such EE programs are currently a small fraction of what is described here.

7. EE growth estimates

EPA's 0.2% 'pace of improvement' (increase in incremental EE per year) is not reasonable. EPA utilizes increases in EE achievement experienced in a select set of states prior to 2011 as a proxy for what can be achieved in all states in the future. These states are not a representative set of states from which to develop a realistic rate of EE increase. Many of these states have had aggressive EE programs with supportive legislative and regulatory environments in place for 20 or more years to get to these best practice levels. Further, the 'pace of improvement' analysis relies upon a time where relatively large and inexpensive lighting measures were able to be counted as EE. As mentioned previously, the new EISA standard has limited, and will continue to limit, the potential of energy efficiency gains in the lighting sector. In addition, as the EPA notes, the pace of incremental EE savings slow over time as the sources of readily available and relatively lower cost EE dwindle (what is known as the "pincher effect"). EPA does not factor these considerations into their application of this pace of improvement to all other states.

**B. Cost Estimates**

EPA's proposal did not use a transparent process in estimating the costs of the proposed EE targets, did not consider all cost elements of EE, and did not give adequate consideration to the impacts of such costs on customers. Therefore, EPA has not adequately evaluated the cost-effectiveness of its proposed standard.

EPA's cost analysis is not transparent. EPA provides little information of the composition, elements, or methods of determining their Levelized Cost of Saved Energy (LCOSE) figures. Implementation of EE requires investment. The costs of such investment include:

- Utility costs to administer the program. These costs are generally recoverable in rates from customers in order to recompense utilities for their expenditures. These costs include:
    - Program administration expenses (advertising, fulfillment, tracking, etc.)

- Incentives to participants (various forms of rebates, buy-downs, etc.)
- Evaluation, measurement and verification (EM&V) activity (to check the validity of the EE impacts)
- Associated regulatory filings and other expenses.

- Recovery of lost-revenues (that portion of rates associated with fixed costs that are not avoided when energy use is reduced through EE programs). These costs are not addressed in EPA analysis. The consequences of not including this cost category in the EPA analysis could substantially change the resulting cost of compliance with the proposed rule.
- Administrator incentives. These costs are not addressed in the EPA analysis. The consequences of not including this cost category in the EPA analysis could also substantially change the resulting cost of compliance with the proposed rule.
- Customer investment in efficiency premiums. Customers pay a portion of the premium (sometimes matching the amount paid by the utility) associated with higher efficiency equipment.

**C. Measurement and Accounting**

The costs to implement EPA's aggressive schedule to achieve the EE levels envisioned by the proposal could be prohibitive. EPA's own estimates of the costs for implementation of the proposed EE requirements in the GHG Abatement Measure Technical Support Document (TSD) Supplemental Models show a substantial level of investments that would result in significant rate impacts on customers.

EPA has not defined the measurement and accounting protocols for EE so that the actual amount of contributions that such measures make toward the proposed standard is uncertain, and there are substantial and complex issues that have no current consensus solutions. Simply inviting comments on these issues does not provide an adequate basis on which to evaluate the goals or provide a basis on which its costs can be reasonably estimated.

1. Attribution

EPA suggests throughout the document that there is flexibility in how emission targets are achieved. As it relates to EE, this discussion extends to whether or not EE is required, what entity would have such responsibility (state, utility – integrated or distribution-only, independent program administrator, etc.), how such credits would be realized (state certificates, credits purchased by EGUs, etc.), in what market such credits are fungible (states, RTOs, trading regions, etc.) and so on. However, unless the states are given absolute discretion to resolve these issues to their own satisfaction, the uncertainties associated with these issues amount to a federal license to reject state submissions if all of the details of the state's EE programs do not conform to standards that EPA never clearly defined.

EPA's TSDs also discuss the challenges associated with attributing the resulting $CO_2$ reductions to specific generators, due the variety of ways that states could design their plans (especially for mass-based standards). In states with competitive generation supplies, there is no mechanism available to make utilities accountable for actual emission reductions at generation facilities that they do not control. Numerous other complicating variables exist, none of which have been resolved, including: allocation of EE measures for multi-state utilities; crediting excess EE measures for 111(d) compliance purposes; how differing market structures such as integrated utility operations or merchant plant ownership affect EE allocations; treatment of states that are net importers or exporters of power; how the particular load profile of utilities affects EE programs and resulting impacts on EGUs through merit order dispatch; and how those impacts evolve as generation profiles change over the compliance period. A full evaluation of these issues is also necessary to assess the effectiveness of any particular EE strategy, or design an effective state plan.

2. Evaluation, Measurement and Validation

EPA failed to establish Evaluation, Measurement and Validation ("EM&V") protocols that need to be relied upon by states to develop state plans. EPA's use of "expired savings", as outlined in the GHG Abatement Measures Technical Support Document, is an unorthodox and unjustified attempt to apply a one-size-fits all methodology that fails to recognize the very substantial variation in the duration of EE savings from particular measures (EE measure "life"). Among the many issues that need to be identified and addressed in the final guidelines before state plans can be proposed include: acceptable sources of EE; net-to-gross approaches; harmonization of differing state EM&V standards; recordkeeping requirements; and protocols for continuing credit from established measures. EPA's plan "to establish guidance for acceptable quantification, monitoring and verification" of EE measures for an approvable EM&V plan "in the coming years" is wholly inadequate. EPA has not even outlined a specific timetable for when it plans to develop this guidance. There is no assurance that EPA will begin its effort to develop guidance on acceptable EM&V methods in time for states to assess the cost and value of these options. If the EM&V methods required by EPA for compliance are significantly different from the EM&V methods already approved by a state PUC for established EE programs, there will be additional implementation delays associated with the development of new state laws and regulations to implement these unknown requirements. Ultimately, measurement affects the stringency of any standard, so without clarity on the measurement techniques that will be applied to these measures, interested parties have not had an adequate opportunity for comment, and EPA has not fulfilled its obligations under Section 307 of the CAA.

3. Impacts

While numerous approaches are discussed to remedy the difficult questions that arise in the area of EE attribution and EM&V, EPA proposes none and simply invites comments. All of these critical questions need affirmative answers or must be left to the states' discretion. Utilities have frequently been permitted to calculate EE savings based on the number of incentives issued, without extensive efforts to verify reductions in energy demand. If reasonable estimates of EE savings can be associated with specific measures and states can effectively track the number of such measures that have been implemented, EPA should deem the plan to satisfactorily comply with EPA's requirements. Otherwise, without definitive and timely guidance on these protocols, states will be second-guessed on the level of EE contributions associated with the proposed measures in their plans. Depending upon EPA's hindsight evaluation, the resolution to these questions, the relative contribution of EE to GHG reductions could be orders of magnitude greater or lesser, and plan approvals unreasonably delayed.

In addition, this uncertainty could lead to substantially underestimating the needed amount and types of EE (leaving the state short of meeting the needed contributions from EE) or overestimating the needed amounts and types of EE (needlessly increasing the overall costs of compliance). The "flexibility" built into this particular building block simply exposes the many substantive issues that remain unresolved, and to which EPA acknowledges it does not have readily available solutions. EPA must do more than simply "invite comments" or assert that there is "flexibility" and provide meaningful guidance on what will or will not be considered adequate EE measures.

### D. Ancillary Issues

There are a number of other important issues that EPA needs to consider with respect to the proposed rule.

1. Electricity Suppliers

EPA established the state EE targets based upon the current retail sales of electricity in the state. Therefore, it is important to note that if these targets were to be proportionately allocated to the various electric suppliers, all such utilities (including investor owned utilities, municipalities, rural cooperative, and competitive retail suppliers) would need to implement EE programs to achieve the standard. Currently in many states only investor-owned utilities are required to implement such programs, while municipal utilities, rural cooperatives, and other suppliers oftentimes are not. Unless states find a way to proportionately share the responsibility to achieve whatever EE target is established, certain customers will be unfairly burdened.

2. Variety of EE sources

EPA should not consider limiting the wide variety of EE sources available to meet any proposed standard. Specifically, sources such as transmission and distribution line efficiency upgrades, design improvements, and operational practice improvements; combined heat and power ("CHP"); improved codes and standards, and other measures should all be eligible to contribute toward whatever EE achievement target is ultimately adopted. Restricting the use of any source of EE will reduce the ability of EE to contribute to the reduction of emissions, and ultimately increase the costs of compliance.

Specifically, transmission and distribution facility efficiency upgrades can be a significant component of any EE program. Distribution efficiency improvements such as Conservation Voltage Reduction ("CVR"), Volt Var Optimization ("VVO"), high-efficiency transformers, low loss conductors, voltage upgrades, phase balancing, and reactive power compensation and control can result in both energy and capacity savings and provide other operational benefits. Similarly, transmission equipment efficiency improvements and practices (such as voltage upgrade of transmission circuits, reduction of substation auxiliary power, low loss conductors, highly-efficient substation transformers, reduction of shield wire losses and corona and insulator losses, etc.), as well as enhanced transmission capacity and system utilization (such as through dynamic line ratings, use of high-temperature low-sag conductors in congested corridors, power routers and energy storage, smart controls, wide-area monitoring, high-performance computation clusters) can allow the grid to operate more safely and improve system utilization, thereby reducing emissions. These measures collectively could substantially contribute to EE achievements and should be creditable toward any reasonable EE targets that are established.

4. Cost-effective EE not included in base case

Regardless of the ultimate disposition of EPA's proposed rule, some states already have plans to continue existing utility-administered programs. EPA's analysis is flawed in that it doesn't recognize the future impacts of these existing EE programs, or future impacts of new (incremental) EE programs, both of which will occur regardless of the implementation of the rule. This has the effect of attributing all future EE achievements solely to this proposal, even though they would occur regardless of its implementation. Therefore, much of the benefit ascribed to the CPP's implementation is overstated, relative to business-as-usual. Further, this has the effect of overstating the EPA base case electricity costs and in turn substantially understating the incremental costs of the CPP (relative to this overstated base case). NERA, an economic modeling and consulting firm, has produced a report that provides a summary of EPA's cost-benefit analysis of the CPP, and highlights this significant bias in the analysis.[394] EPA should re-examine the RIA for this rule, and include the likely impact of ongoing implementation of existing state programs in its base case.

5. Beneficial use

The increased use of electricity in other sectors (*e.g.*, electric vehicles, port and off-road vehicle electrification) can produce many benefits, including reduced $CO_2$ emissions from those sectors. At the same time, these activities increase the demand for electricity (and in turn, can increase $CO_2$ emissions from regulated sources). Given that EPA acknowledges the importance of the role of electric vehicles in reducing emissions from the transportation sector in the future, the effects need to be considered in the proposed rule.

[394] NERA Economic Consulting, *Potential Energy Impacts of the EPA Proposed Clean Power Plan,* (2014), Appendix C.

6. Timing

Many states have established legislation and extensive regulatory processes that codify the EE practices of utilities in their jurisdictions. The resulting requirements related to achievement of standards, cost caps, evaluation processes, and ratemaking activities oftentimes have established schedules that are inconsistent with the proposed rule. Further, a portion of these processes have a direct bearing on the measurement and accounting issues identified earlier that the EPA will address “in the years to come.” These specifics will need to be determined prior to the States initiating legislative or regulatory action to incorporate any such measures into a proposed state plan. Further, for some states (such as Texas), legislators meet every-other-year, therefore the ability to develop state plans may take more than 24 months. This leaves inadequate time to address numerous important issues prior to initiating activity to comply with EPA’s proposed rule. In addition, EPA assumes a ramp-up in EE achievement starting in 2017, several years prior to the proposed rule becoming enforceable. EPA provides no justification for using a standard of performance that begins prior to the rule taking effect.

## IX. EPA has failed to describe the mechanisms states can use to develop and implement a plan that will reliably demonstrate compliance.

EPA's description of the criteria for developing and evaluating state plans focuses primarily on issues related to federal enforceability and bureaucratic administration.[395] It spends no time evaluating whether the framework laid out in the CPP provides a reasonable foundation upon which states can build a plan that is achievable or will reliably demonstrate compliance. Indeed, the overall structure, the multiple "building blocks," and the independent factors that influence their achievability, make the task of designing and implementing a plan that can consistently deliver emission reductions year-over-year, as contemplated by EPA, a practical impossibility.

There are a number of legal, technical, and practical concerns and uncertainties that make implementation of the proposed rule unworkable. Many of these unknowns relate to the assumptions underlying each building block, regulatory strategies that are unproven, levels of implementation that are technically and practically unachievable, or interactions that are not feasible to design or enforce within the existing statutory and regulatory authorities of the states.

EPA acknowledges that some of these issues "introduce practical enforceability considerations under a state plan."[396] But instead of fully evaluating these issues, EPA relies exclusively on the purported "flexibility" that the agency believes states have to address any challenges associated with implementation. This claimed "flexibility" is illusory. There is no way for states to assure that individual generating units will achieve the emission reductions associated with block 1, and no technical basis upon which EPA can conclude that the projected emission reductions will actually occur, because EPA does not evaluate the extent to which such measures have already been implemented, and did not properly account for the heat rate increases associated with recent control equipment installations. There is no way for states to control system dispatch decisions that are entrusted to regional authorities, and simply attempting to "freeze" emissions from designated facilities in 2020 based on projected emissions and generation that accommodate the effects EPA hopes to achieve through building blocks 1 and 2 does not adequately account for the many factors that introduce variability into existing units' utilization and emissions, including weather patterns, unanticipated equipment problems,

395 79 Fed. Reg. at 34,900 – 34,911.

396 "State Plan Considerations TSD." U.S.EPA. June 2014. p.10.

and changes in local load conditions. The output of renewable resources similarly is heavily influenced by weather conditions, equipment condition, and other factors that are neither controlled nor controllable by the designated facilities or the states, and EPA has misinterpreted existing state standards by ignoring the extent to which those standards are currently satisfied by participation in multi-state REC markets, the extent to which they are satisfied in whole or part through energy efficiency measures or alternative payments, and the extent to which they rely on unique resources whose status as "renewable" energy sources in any future section 111(d) plan is uncertain. These errors make EPA's cumulative targets unreasonable and arbitrary. Finally, EPA has no authority to regulate the behavior of consumers, and its simplistic evaluation of the potential for future energy efficiency measures ignores fundamental aspects of program design and achievability. There are errors in each and every one of the blocks upon which the state goal calculation is based that make the final result arbitrary and capricious. All of these errors inflate the prospects for future emission reductions, and simply shift the search for effective ways to meet the arbitrary goals from one building block to another and beyond, to measures EPA admits are not cost-effective, in a continuous loop of legally, technically, and practically flawed options that impairs the development of any workable compliance solution.

Further, the process and aggressive schedule to design, approve, and implement state compliance plans is unnecessarily disjointed and unachievable. While EPA attempts to analogize the CPP implementation process to the process of developing state implementation plans for ambient air quality standards, the two programs are significantly different. The CPP is an unprecedented effort to create an expansive framework that goes far beyond emission rates that can be achieved through control installations or changes in operational practices at designated facilities alone. It is unrealistic for EPA to expect the implementation timelines to be similar because the proposed CPP involves a unique scope and complexity of factors that requires extensive coordination among a broad number of state and federal regulatory agencies, the regulated community, and other interested parties. This requires a process that is methodical, collaborative, and well-informed – a process that requires a more extended schedule than that envisioned by EPA, even with the proposed extension options for states to develop plans.

### A. Errors in EPA's state goal calculations impair their viability

In order to fully evaluate compliance options and attempt to develop viable implementation strategies, states must have an accurate and complete understanding of how the goals are calculated, and what impact changes in the calculation methodology will have on their compliance obligations. Such information is difficult to elicit from the technical resources placed in the docket, and would have been enhanced by including: (1) detailed output form EPA's IPM modeling runs; (2) clear background discussion of the alternative renewable energy goals and associated detailed year-by-year goal calculations; and (3) sample compliance calculations for multiple compliance years using a portfolio approach that illustrate the "flexibility" available to states in designing approvable programs. None of this information was available in the docket at the time of proposal, and much of it remains unavailable.

EPA's NODA, published on October 30, 2014,[397] increased, rather than decreased, the confusion and uncertainty regarding the goal calculation methodology, and added data to the record but failed to provide any insight on the impacts of using alternative base years, multi-year averaging, or changing the goal calculation by reducing fossil generation rates as renewable and energy efficiency measures are implemented during 2020-2029. Attached as Appendix D is a list of the issues upon which EPA requested comments in the initial proposal, as expanded by the NODA. As noted in the appendix, most of these requests propose alternative approaches or changes that affect the stringency of the state goals, but EPA provided no insight into what those impacts would be. The two exceptions to this general rule are the Option 2 state goals, and the goal calculations provided that rely solely on implementation of blocks 1 and 2, both of which were provided in the initial proposal. None of the alternatives described in the NODA have been used to calculate new state goals. There are multiple combinations of the alternatives proposed by EPA, and the outcome of each combination can result in unpredictable impacts on the ultimate obligations of the states - obligations that EPA says represent immutable standards against which any plan submitted by the state will be judged.[398]

AEP attempted to investigate how changes to the underlying information used to calculate the state goals would actually impact the goals. For example, EPA assigned states to

[397] 79 Fed. Reg.
[398] 79 Fed. Reg. at 34,892 ("As promulgated in the final rule following consideration of comments received, the interim and final goals will be binding emission guidelines for state plans.")

"regions" for purposes of identifying best practices and calculating the portion of the state goals attributable to development of renewable resources. However, based on the in-state resources available for development, certain regional average targets appear overly aggressive for certain states. AEP investigated the impact of "re-assigning" states to regions with more similar resource bases, and discovered that such re-assignments would actually *increase* the amount of renewable generation included in the calculation of the interim and final goals. Appendix C shows that if Arkansas and Louisiana were assigned to the Southeast region, which has a regional average target of 10 percent, instead of being included in the South Central Region, which has a regional average target of 20 percent, the amount of renewable energy included in the calculation of the interim goal would *increase* from 3,370,253 MWh to 4,848,761 MWh for Arkansas, and from 4,932,549 MWh to 7,282,579 MWh for Louisiana. This is a facially absurd result. Similarly, the base year upon which the goals are calculated makes a substantial difference, but the direction and extent of that difference are influenced primarily by local weather patterns, unit availability, and other unrelated factors.

AEP compared the renewable energy that would be included in the state goal calculations for states within the East Central, Southeast, and South Central Regions, using 2013 data, with the results of EPA's calculations using 2012 data. For all regions, changing the base year resulted in different goals and different rates of progress toward the regional goals. In certain regions, using 2013 data instead of 2012 data allowed the state to meet the regional target for 2020-2029. EPA's NODA suggests that other years may be used in the calculation of the final goals, without providing the kind of quantitative data necessary to evaluate the impact of such a change, and without explaining why any specific year or group of years is a more reasonable basis upon which to make such a calculation. EPA's inclusion of additional data in the record for this rulemaking at this late date does not cure the lack of notice and inability to effectively comment on alternatives that the agency itself has neither evaluated nor proposed, and cannot be used a means of securing *carte blanche* to perform additional calculations and derive an entirely new set of state goals that will appear for the first time in the final rule. Such tactics are fundamentally inconsistent with the agency's obligations under Section 307 of the CAA.[399]

Prior to promulgating a final rule, EPA should, at a minimum:

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[399] 42 U.S.C. § 7607(B); see also *Western States Petroleum Assoc. v. EPA,* 87 F.3d 280, 284 (9th Cir. 1996)..

- reconcile the extensive legal and technical issues that a have been identified regarding their interpretation, evaluation, and determination of the BSER;
- address the significant errors identified in the proposed state goal calculations;
- fully evaluate the broad scope of implementation issues that must be resolved and the corresponding regulatory agencies and other parties involved; and
- select a representative basis for the final guidelines, and present the information, data, sensitivity analyses, and a complete set of background information, and allow an opportunity for public comment on the proposal

**B. Issues within each building block make implementation unworkable**

As detailed in the specific comments for each building block, a number of issues have been identified regarding the underlying assumptions used by EPA. These issues create significant uncertainties that greatly diminish the potential for states to translate those assumptions into feasible requirements that can be implemented and enforced. A summary of these uncertainties and implementation concerns follows below.

1. Improvements made through building block 1 cannot be reliably projected or enforced.

As detailed in Section V above, it is unclear how EPA's assumptions within building block 1 could be implemented and enforced. Simply, it is infeasible to identify or develop a set of heat rate or $CO_2$ emission rate limitations that could be applied to all designated facilities within the regulated source categories, given the diversity of existing sources and the large number of known and unknown, controllable and uncontrollable variables that impact heat rate performance. AEP evaluated recent permits issued for both coal-fired and NGCC units across the nation, and found *no* examples of a permit where a heat rate standard has been imposed as an operating limit.[400] The lack of reliable information in the record upon which to assess the potential opportunities for improvement, the amount of potential improvement that may be realized, the sustainability of any improvement, and the lack of any real-time heat rate measurement technology capable of identifying and isolating the improvements associated with particular operating practices or equipment upgrades, support the development of a work practice standard. Such a standard could then be utilized by the states to evaluate future outage work and assure that the efficiency of the existing fleet is maintained and improved consistent with the

[400] See Appendix D

relevant factors that control a valid section 111(d) standard, including the remaining useful life of affected units. However, reliance on such a standard does not provide the states with readily quantifiable reductions that can be used to demonstrate achievement of a rate-based goal or mass emission cap. EPA must acknowledge these uncertainties and revise its criteria for approval of state plans to accommodate a reasonable work practice standard.

2. Building block 2 cannot require states to interfere with the economic dispatch or reliable operation of the grid.

Likewise for building block 2, it is unclear how EPA's assumed capacity factor could be effectively implemented and enforced because of various uncertainties related to whether the design, support infrastructure, and current permits and regulatory requirements for the existing NGCC fleet are sufficient for all units to sustainably achieve a 70% capacity factor. Even if all of these uncertainties were addressed, states cannot interfere with the existing regulatory authority and enforcement responsibility of the federally authorized agencies that control unit dispatch decisions and plan for the reliable operation of the electricity grid. Capacity factors at NGCC units will be influenced by a number of uncontrollable factors, including weather, local transmission constraints, fuel availability, performance of lower cost resources, and other factors. Further, it is unclear how EPA would envision a regulatory requirement be structured and enforced to achieve the types of redispatch assumptions that were used to derive the state goals. This includes the question of whether capacity factor is calculated using nameplate or summer capacity, but also, it includes uncertainties regarding how capacity factors are derived. AEP reviewed recent permits for NGCC units and other fossil units and found no examples of facilities that have an enforceable minimum capacity factor limit.[401] EPA's own modeled outputs indicate that the targeted 70 percent capacity factor used to create the state goals would not in fact be achieved by the proposed CPP. EPA must explain how states could develop a plan that produces results its own model refutes, or recognize that the proposal does not accurately reflect the operation of the electricity grid.

3. Building blocks 3 and 4 are not enforceable against designated facilities

EPA's proposal takes the form of a "portfolio approach" under which states would apply traditional "emission standards" to affected EGUs, and other requirements to other "affected

[401] See Appendix D.

entities" that, taken as a whole, will achieve the required level of emission performance.[402] Alternatively, EPA suggests that a "standard of performance" could be adopted by the states that places the entire burden of achieving the level of performance reflected in the state goals on affected sources. However, EPA also recognizes that states have varied regulatory frameworks for the electric industry that could impede their ability to enforce requirements related to building blocks 3 and 4 directly against many designated facilities. Certain owners and operators of EGUs are not subject to rate regulation or review of new resources, and have no retail customers. As such, they have no capability to require the addition of renewable resources within a state, and no ability to provide incentives for adoption of EE measures among retail customers. EPA proposes that states can create other "compliance entities" to assume those responsibilities,[403] but fails to explain how these entities (which emit nothing that is subject to regulation under the CAA) became subject to the jurisdiction of the environmental regulators, or how states could rely on activities by unrelated third parties to reduce emissions at independently operated facilities.

This framework raises a number of unanswered questions. Who is the entity being regulated? Who has enforcement responsibility? How are interstate considerations addressed with respect to credits for efforts within each block? What accounting processes will be required to assure no double counting of renewable energy credits and how will these interact with (or interfere with) existing markets and contractual rights? What EM&V requirements will apply to EE programs within and across state boundaries? Since EPA assumes that states will take early action prior to approval of their plans, what assurance can EPA give the states that credit that will be available for those efforts?

Separately, a number of concerns exist regarding the technical feasibility of potential opportunities to establish and expand renewable energy and EE programs, especially if these programs are implemented but fail to achieve the required reductions at affected units. Similarly, the consideration of nuclear units in the implementation plan raises issues regarding regulatory authority, enforcement responsibility, and compliance demonstrations if EPA intends the capacity factor assumptions used in calculating state goals to become an enforceable requirement

[402] 79 Fed. Reg. at 34,891.
[403] 79 Fed. Reg. at 34,901.

in order to claim a "credit" in the state's compliance demonstration. All of these issues are inadequately addressed in the proposal.

C. Uncertainties with the state plan development process and design options must be resolved before states can propose implementation plans to EPA

Separate from the concerns regarding the feasibility of developing requirements that represent the assumptions applied in each building block, there are a number of process related uncertainties regarding the steps required to design, approve, implement, and enforce state compliance plans. Detailed comments on these concerns follow.

1. EPA's Proposal to Allow State Plans to Include Federally Enforceable Obligations on "Affected Entities" Exceeds EPA's Statutory Authority.

In 2011, the U.S. Supreme Court provided an overview of the process by which EPA and the states must work together to craft greenhouse gas performance standards for existing sources:

> Section 111 of the Act directs the EPA Administrator to list "categories of stationary sources" that "in [her] judgment ... caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." § 7411(b)(1)(A). Once EPA lists a category, the agency must establish standards of performance for emission of pollutants from new or modified sources within that category. § 7411(b)(1)(B); see also § 7411(a)(2). And, most relevant here, § 7411(d) then requires regulation *of existing sources* within the same category.[404]

In other words, once EPA promulgates a section 111(b) NSPS, section 111(d) requires EPA to issue regulations under which the states will regulate existing sources within that same category of sources. In particular, section 111(d) directs EPA's Administrator to prescribe regulations that establish a procedure under which states submit plans that do only two things: (1) "establish[ ] standards of performance *for* [those] existing source[s]," and (2) "provide[ ] for the implementation and enforcement of such standards of performance."[405]

EPA, however, is "proposing to interpret CAA section 111 as allowing state plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce $CO_2$ emissions from affected sources."[406] EPA's proposal explains that such an approach "could include enforceable $CO_2$

[404] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-2538, 2539, 180 L. Ed. 2d 435 (2011) (emphasis added) (footnote omitted).
[405] 42 U.S.C. § 7411(d)(1).
[406] 79 Fed. Reg. at 34,903.

emission limits that apply to affected EGUs [electric generating units] as well as other enforceable measures, such as RE [renewable energy] and demand-side EE [energy efficiency] measures, that avoid EGU $CO_2$ emissions and are implemented by the state or by another entity."[407] In other words, a "portfolio" plan would "include a combination of emission limitations that apply directly to the affected sources *and other measures* that have the effect of limiting generation by, and therefore emissions from, the affected sources."[408] EPA offers four primary arguments in support of its theory that state plans could impose federally enforceable obligations on third-party "affected entities," none of which survives a facial review.

EPA's first argument "is based, in part, on CAA section 111(d)'s requirement that states set performance standards 'for' affected sources."[409] EPA argues that RE and EE measures are "for" EGUs because "they would have an effect on affected sources by, for example, causing reductions in affected EGUs' $CO_2$ emissions by decreasing the amount of generation needed from affected EGUs."[410] This argument is contrary to section 111 in at least two ways. First, as EPA itself states (but then immediately disregards), section 111(d) plans are supposed to "establish[ ] *standards of performance*" for existing sources.[411] Renewable energy generating technologies and demand-side energy efficiency measures (such as "energy efficiency programs, building energy codes, state appliance standards ..., tax credits, and benchmarking requirements for building energy use")[412] are not "standards of performance." A "standard of performance" is "a standard for emissions of air pollutants"[413] or "a requirement of continuous emission reduction."[414] Thus, no matter how one defines "for," RE and EE are not "standards of performance for any existing source" for purposes of section 111(d)(1). Second, the Act makes clear that "standards of performance *for* any existing source" must be standards that are applied *to* those existing sources, and not merely standards that "*have an effect on*"[415] those sources. There are only four sentences in section 111(d), and two of those sentences make this conclusion crystal clear:

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[407] 79 Fed. Reg. at 34,837.
[408] 79 Fed. Reg. at 34,851.
[409] 79 Fed. Reg. at 34,903.
[410] 79 Fed. Reg. at 34,903.
[411] 42 U.S.C. § 7411(d)(1).
[412] 79 Fed. Reg. at 34,872.
[413] 42 U.S.C. § 7411(a)(1).
[414] 42 U.S.C. § 7602(l).
[415] 79 Fed. Reg. at 34,903 (emphasis added).

> Regulations of the Administrator under this paragraph shall permit the State *in applying a standard of performance to any particular source* under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of *the existing source to which such standard applies*. ... In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives *of the sources* in the category of sources *to which such standard applies*.[416]

Thus, viewing the phrase "standards of performance for any existing source" in context, as Supreme Court precedent requires, section 111(d) standards of performance are standards that apply *to* sources in the relevant source category, not just requirements that *affect* such sources. EPA's proposal to broaden section 111(d)(1) to include measures that are not "standards of performance" and do not apply to a regulated "existing source" is flatly contrary to the clear language of the statute.

EPA's second argument is that section 111(d) does not explicitly "prohibit[ ] states from including measures other than performance standards and implementation and enforcement measures," and that "the principle of cooperative federalism ... supports providing flexibility to states to meet environmental goals ... ."[417] This argument is fundamentally inconsistent with the fact that EPA is "a creature of statute," and has "only those authorities conferred upon it by Congress."[418] In section 111(d), Congress conferred authority on EPA to prescribe regulations under which states would submit plans that include (1) "standards of performance" and (2) "[provisions] for the implementation and enforcement of such standards of performance."[419] Congress did not authorize EPA to prescribe regulations under which states may submit plans that include measures *other* than performance standards and implementation and enforcement measures. Because Congress did not give EPA that authority, EPA does not have that authority. And, while it is true that states may choose to pass their own laws to reduce the $CO_2$ emissions of electric generating units in those states, such laws would not be part of any Section 111(d) plan if they did not constitute performance standards, or implementation and enforcement measures for performance standards.

As a third argument, EPA suggests that renewable energy and energy efficiency measures might qualify under the act as "implementation" measures. EPA explains: "if the state's plan

[416] 42 U.S.C. § 7411(d)(1) and (2).
[417] 79 Fed. Reg. at 34,903.
[418] *Michigan v. EPA*, 268 F.3d at 1081.
[419] 42 U.S.C. § 111(d)(1).

achieves the emission performance level through rate-based emission limits applicable to the affected sources, coupled with a crediting mechanism for RE and demand-side EE measures, we propose that RE and demand-side EE measures may be included in the plan as 'implement[ing]' measures because they facilitate the sources' compliance with their standards of performance."[420] This position assumes that "implementation" can be understood to mean "facilitation." It cannot, by any common understanding of the word "implement." WEBSTER'S defines "implement" to mean "to carry out"; "to give practical effect to and ensure of actual fulfillment by concrete measures[.]"[421] This is consistent with EPA's use of the word "implement," in proposed Subpart UUUU, to mean "carry out."[422] EPA's argument also misreads the statute. A state's section 111(d) plan must, again, "(1) "establish[ ] standards of performance" and (2) "provide[ ] for the implementation and enforcement *of such standards of performance*."[423] The Clean Power Plan's "emission performance levels," or "state goals,"[424] are not "standards of performance." Standards of performance are what the states would use to "*achieve* [t]he emission performance level."[425] Thus, the fact that RE and EE measures might help states achieve their emission performance levels could mean, at most, that such measures help the states "implement" *those emission performance levels*; it does not mean that those measures would help *EGU*s achieve their *standards of performance*. EPA acknowledges that RE and EE measures "are not directly tied to emission reductions that affected sources are required to make through emission limits" and "are not intended or designed to assist affected EGUs in meeting the performance standards."[426]

Finally, and in the alternative, EPA suggests that the state emission performance levels (*i.e.*, the "state goals") *could* be considered "standards of performance," "because it is in the nature of a requirement that concerns emissions and it is 'for' the affected sources because it

420 79 Fed. Reg. at 34,903.
421 WEBSTER'S THIRD NEW INTERNATIONAL DICTIONARY 1134 (1981).
422 *See*, *e.g.*, Proposed 40 C.F.R. §§ 60.5710 ("you must submit a state plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart.") and 60.5720 ("If you do not submit an approvable state plan the EPA will develop a Federal plan for your state according to § 60.27 to implement the emission guidelines contained in this subpart.").
423 42 U.S.C. § 7411(d)(1) (emphasis added).
424 *See* 79 Fed. Reg. at 34,903.
425 *See*, *e.g.*, 79 Fed. Reg. at 34,851 (emphasis added); *see also id.* at 34,853 ("[E]ach state must develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards.").
426 79 Fed. Reg. at 34,903.

helps determine their obligations under the plan."[427] EPA does not explain this point, but the agency presumably intends to argue that if the state goals are "standards of performance," then EE and RE measures would be "implement[ing] measures that could be included in the state plans. This argument, like the first three arguments, suffers from obvious flaws. "Standard of performance" does not mean "a requirement that concerns emissions"; it means, again, "a standard for emissions of air pollutants"[428] or "a requirement of continuous emission reduction."[429] A standard of performance is *for* an existing source only if it is applied *to* that source. The state goals cannot be standards of performance because, as EPA has explained, the state goals "are *not* requirements on individual electric generating units."[430] The state goals cannot be "standards of performance" because EPA has no authority to set standards of performance; it is the state plans that establish the standards of performance.[431]

For all of these reasons, states could not adopt a portfolio approach that includes *federally* enforceable obligations on third-party "affected entities" when establishing their section 111(d) plans. Such an approach would be directly contrary to the clear commands of section 111(d) and, as such, would be unlawful. This does not mean, however, that states could not use state renewable energy or energy efficiency requirements as a method to help the states achieve their emission performance levels. AEP agrees with those stakeholders who suggested "that states could rely on RE and demand-side EE programs [that are enforceable under state law] as complementary measures to reduce costs for, and otherwise facilitate, EGU emission limits without including those measures in the CAA section 111(d) state plan."[432]

2. EPA's Proposal to Regulate States or State Agencies as "Compliance Entities" Is Inconsistent with the Clean Air Act's Premise of Cooperative Federalism and Raises Serious Enforceability Concerns

The building block assumptions relate to both emission sources that have historically been regulated by the Clean Air Act, as well as other entities who, until this proposed rule, would

[427] 79 Fed. Reg. at 34,903.
[428] 42 U.S.C. § 7411(a)(1).
[429] 42 U.S.C. § 7602(l).
[430] EPA, *Fact Sheet: Clean Power Plan / National Framework for States – Setting State Goals to Cut Carbon Pollution* (June 13, 2014) (*available at* http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-setting-goals.pdf).
[431] *See* 42 U.S.C. § 7411(d)(1).
[432] 79 Fed. Reg. at 34,902.

have not been subject to the Act or to regulation by state environmental agencies. EPA refers to this expanded scope of regulated entities by noting that:

> a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.[433]

And further comments:

> responsible entities in an approval state plan may include an owner or operator of an affected EGU, other entities with responsibilities assigned by a state, or the state itself. Other entities might include an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity. State responsibility might include obligations that are assumed directly by a state agency, authority, or other state entity to carry out aspects of the state plan. While this approach provides states with broad discretion to develop plants that best suit their circumstances and policy objectives, assigning responsibility to other parties regulated by the state, private or public third-party entities, or state entities *raises enforceability considerations*.[434]

Various provisions of EPA's proposed Clean Power Plan rely on the assumptions that states themselves may take responsibility for obligations under a section 111(d) plan, and that such states would be subject to citizen suit if they failed to fulfill those obligations. For example, EPA solicits comment on a "state commitment approach" to section 111(d) plans, under which states would commit to implement, say, RE and demand-side EE programs "that would achieve a specified portion of the required emission performance level on behalf of affected EGUs."[435] EPA explains that those commitments would not be part of the state plan, per se, and would not be federally enforceable.[436] Nonetheless, EPA asserts, states "fail[ing] to achieve the expected emission reductions ... could be subject to challenges – including by citizen groups – for violating CAA requirements and, as a result, could be held liable for CAA penalties."[437] Alternatively, EPA suggests, states could "impose the full responsibility for achieving the emission performance level on the affected EGUs, but ... credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures" and "then assume responsibility for that credited amount of emission reductions ...

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[433] Id. p. 10.
[434] Id. p. 13. (emphasis added)
[435] 79 Fed. Reg. at 34,902.
[436] *Id.*
[437] *Id.*

."[438] EPA's proposal ignores important restrictions on the ability to sue state agencies under the Clean Air Act's citizen suit provisions.

Section 304 of the Clean Air Act authorizes "any person" to commence "citizen suits" against "any person (including ... any ... governmental instrumentality or agency to the extent permitted by the Eleventh Amendment to the Constitution) ... who is alleged to have violated ... or to be in violation of" certain requirements of the Clean Air Act.[439] The relevant provisions of section 304 would permit suit only for violations of "an emission standard or limitation" or "an order issued by the Administrator or a State with respect to such a standard or limitation."[440] "Emission standard or limitation under this chapter" is defined, in section 304(f)(3), to include "any requirement under section 7411 or 7412 of this title (without regard to whether such requirement is expressed as an emission standard or otherwise)[.]"[441] Section 304 does not, however, provide citizens the ability to sue state agencies for failure to administer section 111 requirements. In *Sierra Club v. Korleski*, the U.S. Court of Appeals for the Sixth Circuit held that "§ 7604(a)(1) does not permit citizen suits against state regulators *qua* regulators. Instead," the court held, "§ 7604(a)(1) is only a means by which "parties may enforce the substantive provisions of the [CAA] against regulated parties[.]"[442]

Consequently, any proposal in EPA's Clean Power Plan that would impose legal responsibility on a state or state agency to undertake measures to comply with the state emission performance goals would be unreasonable, as it would be effectively unenforceable by citizen suit plaintiffs.

The assumptions applied to the building blocks involve regulating entities, operations, and programs that exceed the existing regulatory jurisdiction of state environmental agencies. It is unclear who has, could have, or should have the authority to establish and enforce limits for the assumptions that extend beyond the current authority of state environmental agencies. Further, the process and time required for individual states to evaluate, design, and establish such authorities is unclear. EPA acknowledges these issues regarding regulatory authority by noting that:

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438 *Id.*
439 42 U.S.C. § 7604(a)(1).
440 *Id.*
441 42 U.S.C. § 7604(f)(3).
442 *Sierra Club v. Korleski*, 681 F.3d 342, 351 (6th Cir. 2012), quoting *Bennett v. Spear*, 520 U.S. 154, 173, 117 S. Ct. 1154, 137 L. Ed. 2d 281 (1997).

...due to differences in state utility regulatory structure, a portfolio approach implemented in a restructured state with retail competition will likely look quite different from one implemented in a state with vertically integrated, regulated electric utilities. This includes the process for developing the portfolio approach, the mechanics for implementing it, the responsible parties, and the regulatory and legal relationships among parties and state regulators.

and

...state public utility commissions (PUCs) often do not regulate these utilities [municipally owned utilities or utility cooperatives]. As a result, implementation of a portfolio approach by these utilities would introduce practical enforceability considerations under a state plan.[443]

EPA alludes to these same concerns and in some cases suggests the need for state legislation to establish the regulatory authority and to potentially fund the implementation of such programs by noting that:

[A] legal arrangement that might be applied under this scenario is legislation directing state executive branch actions, or actions by independent state authorities under the plan, if obligations are not met. Depending on the form of legislation, this could also provide citizens with the ability to compel state action under state law, if obligations are not met under a state plan. An additional consideration is whether such legal arrangements, if related to a renewable energy or end-use energy efficiency deployment program, should also specify a stable budget authority or funding source through the plan performance period, or other provisions, to ensure that programs are implemented as projected under the state plan.[444]

The willingness of states to undertake such legislative initiatives and the timing required for states to successfully enact such initiatives is a significant unknown, especially in context with extensive concerns regarding the nature and scope of existing state regulatory authorities that may be ceded to EPA.

EPA is correct that the construct of the proposed rule "raised enforceability considerations." EPA's proposal attempts to regulate entities that are not subject to the Clean Air Act, do not own assets that are emission sources (i.e. distribution only companies), or that do not own any assets associated at all with the generation or delivery of electricity (i.e. state agencies responsible for energy efficiency programs). These concerns will impede state plan development, because they exceed EPA's authority and the authority of state agencies under the CAA.

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[443] Id. pp.9-11.

[444] "State Plan Considerations TSD." U.S.EPA. June 2014. pp.17-18.

### 3. Uncertainties Affect Plan Development Due to Reliability Issues

EPA projects that implementation of the proposed rule will result in significant changes in how and where electricity is generated. The agency estimates that as a result of implementing the proposed rule up to 49 GW of existing coal-based generation will retire by 2020, that existing NGCC units will be utilized more, and that new renewable energy development and energy efficiency programs will be implemented. Each of these outcomes must be evaluated by utilities, state utility commissions, and regional transmission organizations in order to assess and to mitigate potential reliability issues. The process for performing such evaluations for an individual state alone could be extensive. Given the fact that the transmission grid crosses state boundaries, and that multiple entities may be responsible for regional grid operations within a single state, the process of evaluating reliability concerns in context with proposed implementation strategies from multiple states, which may or may not be collaborating together, becomes significantly more complex and time consuming. As a result, the need to evaluate and respond to reliability issues creates significant unknowns regarding the process and time required for completing such analyses.

### 4. Uncertainties Regarding Multi-State Plans

The proposed rule presents the option for states to collaborate to develop multi-state plans. But such plans will require coordinated action by multiple state legislatures and regulatory agencies to come to fruition, and may even require Congressional approval before multi-state plans become a viable option for compliance.[445] The process and time required to develop an acceptable multi-state framework, coordinate plans by individual states, provide for adequate review by regional transmission authorities or other reliability organizations, and secure approval by Congress and EPA is not adequately considered or addressed in the EPA proposal. EPA has not adequately disclosed the consequences if one state is unable to meet all of its obligations, but others subject to a regional plan are in compliance. Unknowns also exist regarding the ability and process for states to exit multi-state plans and the corresponding impacts on all parties involved. For all of these reasons, EPA's proposal lacks sufficient detail to allow states to proceed with the development of multi-state plans.

[445] *See* 42 U.S.C.§ 7402 (a), (c) (although Congress expressly encouraged the Administrator to facilitate interstate cooperation, and authorized states to negotiate and enter into agreements or compacts, no such agreement or compact is binding on a state until it has been approved by Congress).

### D. EPA has overstated the degree of implementation "flexibility" available to states

Throughout the proposed rule, EPA refers to states having flexibility in the design of implementation plans. In reality, the purported flexibility is insufficient for developing any workable compliance solution. As previously discussed, significant flaws have been identified in EPA's assumptions and goal calculations for both blocks 1 and 2 Correcting these assumptions should reduce the stringency of the state goals, as there are significantly fewer opportunities for heat rate improvements available, and significantly less NGCC capacity is available for redispatch. Similarly, EPA's evaluation of the opportunities for increasing renewable energy and EE are seriously flawed. As a result, states ultimately have very little flexibility in developing plans, and no guidance on how alternative measures will be "credited" if they are relied on. These omissions must be addressed if states are to be equipped to investigate and adopt alternative measures as part of their state plans.

1. Potential compliance options referenced by EPA outside of the building blocks do not provide additional "flexibility"

EPA notes that other options outside of the building block assumptions may be available that would provide additional "flexibility" to states in developing implementation plans. These other options include the potential use of partial carbon capture and storage ("CCS") technologies and technologies to improve the efficiency of the transmission system, both of which are unproven, insufficient, and/or are not cost-effective solutions for achieving the proposed state goals. As noted in the extensive comments that AEP provided on the proposed 111(b) standards for new sources, CCS technologies have not been adequately demonstrated to be technically feasible or cost-effective for fossil fuel-fired generating units.[446] With respect to measures to improve the efficiency of the transmissions system, technologies do exist to improve performance. However, significant concerns remain regarding the broad application, cost, and performance of such technologies.[447]

2. EPA's proposed alternative mass-based program does not provide additional compliance flexibility

EPA has proposed basic guidelines for states/regions to convert emission rate guidelines into a binding mass-based emission cap. EPA guidance is largely based on a prospective

[446] See Appendix G for relevant AEP comments of CCS that were submitted on the proposed 111(b) rule. 2014.
[447] Id

modeling of emissions to demonstrate that a mass-based system is “at least as stringent” as EPA's rate-based goals for affected sources.

However, the measures that EPA has considered as part of an adjusted emission rate goal may or not directly displace emissions from affected sources in the same manner EPA has proposed due to the interconnected nature of the electric grid and the fact that under a least cost dispatch approach, emissions are always reduced from the marginal generating units at a specific point in time. (e.g. increased use of renewable energy or energy efficiency measures could at times displace emissions from out of state generation or gas-fired generation which would either not affect emissions from affected sources within a state or at a minimum not to levels EPA has assumed.) Therefore, states may be disadvantaged in setting a mass-based target even though they offer enormous benefits in terms of simplicity in implementation and market design.

Further, EPA’s conversion guidelines are also inadequate as it is unclear what modeling assumptions may be acceptable to EPA for approval of mass-based plan. While EPA has subsequently released a Technical Support Document discussing an “illustrative” approach for translating the emission rate-based carbon dioxide goals into mass-based goals, states may wish to take another approach to deriving their goals. EPA should still provide further guidance on what could be a workable system outside of the "illustrative" approach. Furthermore, EPA needs to make an explicit determination that mass-based goals could be codified within a SIP or SIPs and approved with no further need for review.

**E. EPA must not infringe on the statutory authority granted for developing state plans, including consideration of the remaining useful life of existing sources.**

EPA relies upon its claims of the “inherent flexibility” in the design of the proposed CPP to explain away its disregard for the elements Congress expressly entrusted to the states’ discretion in developing “standards of performance” under section 111(d). But EPA cannot write its own authorizing legislation, and must follow the clear prescription laid out in the statute.[448]

Section 111(d) unequivocally places the responsibility and authority for developing enforceable standards of performance for existing sources with the states. And Congress described the latitude EPA *must* provide to the states as follows:

[448] *UARG v. EPA,* 134 S.Ct. at 2446.

> "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies."[449]

The facilities and equipment to which the proposed guidelines apply are capital-intensive, long-lived assets, many of which have historically operated for 50 to 60 years. In addition, at most of these facilities, significant additional investments have recently been made to comply with other environmental regulations. Such investments have been made due to programs like the MATS rule[450] and the Regional Haze program "best available retrofit technology" or BART requirements.[451] In analyzing the cost-effectiveness of controls under the BART guidelines, EPA has often used the "remaining useful life" of a source as an input to that analysis, and its default assumption is that existing sources will continue to operate for 20 years after completing the retrofit of such controls.[452]

However, for purposes of this rulemaking, EPA assumes that all existing coal-fired sources that will be operating in 2020 and beyond should gradually reduce their generation and be replaced by lower or non-emitting generation or EE measures over a fifteen-year period. The most egregious example of this scenario is in Arizona, where EPA's model predicts that all coal-fueled EGUs will disappear before the final goals become effective in 2030. However, EPA's IPM outputs demonstrate that the integrated operation of the four building blocks would result in the retirement of many additional sources, none of which have reached the end of their "remaining useful life."

The magnitude of the recent investments in the existing fleet is staggering. AEP alone has spent approximately $3.5 billion to upgrade its existing units, and several compliance projects are still underway. Nowhere does EPA take into account the loss of these assets, and their potential impact on customer rates. Nor does EPA explain how it can override the discretion Congress specifically vested in the states to avoid such adverse economic impacts. EPA must address these costs, and revise its proposal to allow states the latitude to design

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[449] 42 U.S.C. § 7411(d)(1).
[450] 40 CFR Part 63, Subpart UUUUU.
[451] 40 CFR §51.308.
[452] *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans*, EPA-R09-OAR-2012-0021, 77 Fed. Reg. 42,833 at 42,854.

programs that do not result in the confiscation of assets, or prematurely force retirements rather than preserving the remaining useful lives of these units.

**F. EPA cannot regulate affected sources under both 111(b) and 111(d)**

AEP supports the comments of UARG, EEI and other organizations, which demonstrate that EPA's proposal to subject units that are modified or reconstructed after the effective date of a state or federal plan under Section 111(d) to the requirements of *both* programs is inconsistent with the plain language of the Clean Air Act. A unit is a *new* unit, or it is an *existing* unit; but it cannot be both simultaneously. If a unit is "modified" or "reconstructed" before such a plan is approved, none of the requirements for "existing" sources should apply. If that change occurs after state plan approval, the unit will no longer be subject to ongoing requirements for "existing" sources. While this could "change the equation" for a state or regional plan as currently envisioned by EPA's existing source proposal, this is simply one more change in the host of changes that will undoubtedly occur over the course of the administration of the program, and one on which EPA needs to provide clear guidance for the states.

**G. EPA's proposed implementation timeline is unachievable**

As illustrated above, the challenges confronting states are many, and EPA's proposal lacks the clarity necessary to guide the development and approval of state plans within the very aggressive time frame outlined in the proposal. The CAA does not set a specific time for the submission of state plans, nor does it establish a rigid compliance deadline for the designated facilities that are to be governed by the plans. EPA should reassess its schedule, given the realities of the tasks it has set before the states.

First, as explained in detail in many of the comments submitted by state agencies, even if EPA substantially revised its proposal to be consistent with the authorities granted by Congress, state regulatory development processes, including the public hearings and other processes required by the CAA, will take more than 13 months to complete. States are ordinarily provided with much more time to develop plans under section 110.[453] RTOs and others have indicated that they see a need for an option to review state plans, consistent with their long-term planning

[453] 42 U.S.C 7410(a) (providing three years for SIP submissions).

responsibilities for the bulk electric system.[454] Since the current planning processes at the RTOs can take up to a year to complete, allowing time for these essential reliability safety checks suggests that a minimum of two years may be necessary to develop sound state plans.

Multi-state planning efforts will take even longer to complete. The Regional Greenhouse Gas Initiative states devoted five years to the planning, legislative, and regulatory development efforts necessary to establish their program. EPA has provided no real world examples to support its time schedule for the development of state or regional plans, and must re-evaluate the time frames included in its proposal.

The second matter of grave concern is the interim compliance goals. EPA has assumed that all of the measures required under building blocks 1 and 2, as well as initial steps to implement block 4 and ongoing renewable energy development efforts, can be completed by 2020, and that assumption significantly affects a state's ability to demonstrate compliance with the 2020-2029 goal. These assumptions are unfounded, and create a "compliance cliff" in many states, as additional coal generation is projected to retire, natural gas pipeline capacity is assumed to be constructed, and all of the transmission additions and mitigation necessary to accommodate these vast changes in the make-up of the bulk electric system cannot be completed within this time frame.[455] The result, according to NERC, is widespread concern over the integrity of the bulk electric system.[456]

EPA has given no reasoned explanation of why it believes the transformation it seeks can be accomplished in less than five years after the final guidelines are published. Its assumptions are inherently unreasonable because they are based upon significant changes in investments occurring without sufficient regulatory certainty to support those changes. EGUs are in large measure regulated entities whose significant investments (whether they be generation, transmission or distribution assets) are subject to the oversight of state regulatory commissions, and are regularly examined in careful detail so as to protect the interests of utility customers. Since this process of regulatory oversight and approval typically occurs at the time the assets are placed in service, utilities must be prepared to demonstrate that the investments were prudently made, or risk disallowance of recovery for all or a portion of the investment. Therefore, until

[454] Comments of the Southwest Power Pool in Docket No. EPA-HQ-OAR-2013-0602, *filed* October 9, 2014 ("SPP Comments").
[455] NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan,* November 2014.
[456] *Id.*

utilities are reasonably confident that the proposed investment is consistent with the contents of a state plan that will not be disapproved by EPA and replaced by a federal plan, they will have no incentive to take measures to implement these requirements. EPA's proposal assumes that there will be as little as 6-18 months between the final approval of a plan by EPA and the initial compliance date in 2020. Such a short period for implementation is arbitrary, unreasonable and unlawful.

EPA has also offered no legal justification for the interim goals. EPA's implementing regulations state that guideline documents shall include, among other information:

> An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.[457]

EPA has said that its "state goals form the EPA's emission guidelines."[458] Thus, EPA's regulations would allow the agency to take into consideration "the time within which compliance with emission standards ... can be achieved" when setting its state goals. As the D.C. Circuit recognized in 1973, whether a particular degree of emission reduction is "achievable" depends on whether the system of emission reduction on which it is based is available, and "the question of availability is partially dependent on 'lead time,' the time in which the technology will have to be available."[459] The regulations would also allow EPA to "specify different [state goals] or compliance times or both for different sizes, types, and classes of designated facilities ... ." They would not, however, authorize EPA to specify different state goals *for different compliance times*, which is what EPA is attempting to do with its interim goals.

Nor are interim state goals necessary under EPA's implementing regulations. State plans under section 111(d) must include compliance schedules.[460] "Compliance schedule" is defined to mean "a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific emission standards contained in a plan or with any

[457] 40 C.F.R. § 60.22(b).
[458] Legal Memorandum at 16.
[459] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
[460] 40 C.F.R. § 60.24(a).

increments of progress to achieve such compliance."[461] Additionally, if compliance will take more than 12 months (which it would, under the CPP), state compliance schedules must include "legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities."[462] The increments of progress in state plans would ensure that states, affected EGUs, and/or affected entities would stay on track to achieve required $CO_2$ emission reductions. Nothing in section 111(d) or Subpart B, however, authorizes EPA to impose its own increments of progress up-front, in the form of interim state goals.

Lastly, EPA's state interim goals may be unnecessary to some extent. EPA has asserted that states and affected EGUs are already undertaking many or most of the measures that make up EPA's proposed BSER. EPA has said, for example, that "[a]verage deployment of RPS-supported renewable capacity from 2007-2012 has exceeded 6 GW per year."[463] EPA reports that "[i]n 2012, RE accounted for more than 56% of all new electrical capacity installations in the U.S."[464] EPA also reports that, according to a study by the Lawrence Berkeley National Laboratory, "efficiency programs are 'posed for dramatic growth over the course of the next 10 to 15 years[.]'"[465] If these studies and projections are correct, states are moving towards increased RE and demand-side EE even without the proposed command-and-control goals of the CPP.

If EPA finalizes a proposal that includes all or significant portions of the building blocks, EPA should eliminate the interim goal and provide states with true flexibility to design a glide path toward compliance.

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[461] 40 C.F.R. § 60.21(g).
[462] 40 C.F.R. § 60.24(e)(1).
[463] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants – GHG Abatement Measures, at 4-3 (June 10, 2014).
[464] *Id.* at 4-7.
[465] *Id.* at 5-19.

## X. EPA Failed to Conduct An Adequate Reliability Analysis, and Does Not Provide Adequate Time in Its Implementation Schedule to Address Electric Infrastructure Needs

The U.S. transmission grid has evolved over the past 100 years to become the intricate system it is today. While flexible and adaptable to small changes in generation or load, the transmission grid is not prepared to accommodate the sweeping changes in the generation portfolio that would result from the CPP. As generation supplies of an electric system change, an evaluation of potential impacts to the transmission infrastructure used to deliver the energy is necessary to ensure reliable operation for the public good. The CPP is not based on any detailed reliability analysis, and would create an unprecedented change to the existing generation fleet through coal retirements and the addition of substantial new renewable generation. The plan essentially forces this sophisticated system to evolve and operate in an entirely different way than its current design, without considering the planning, analysis, and other activities that must precede such changes.

For utilities, cooperatives, balancing authorities, and many others, keeping the lights on is job #1. Changes to the mix of generation resources, even in isolation, require a full assessment of the capabilities of the transmission grid to be able to withstand the proposed changes in the generation fleet. As was demonstrated during implementation of the Mercury and Air Toxics Standards ("MATS") rule,[466] regional transmission authorities played a critical role in protecting the grid from the unintended consequences of generator retirements. Generators provided notice of their compliance plans to state authorities and RTOs, and together identified the activities and construction projects necessary to maintain reliability in those new configurations. In many cases, these assessments indicated the need for additional time, and states worked with generators to provide the needed flexibility in scheduling.

The number of retirements projected to occur as a result of EPA's CPP proposal far exceeds those projected to occur as a result of MATS implementation, and is estimated at between 46 and 49 GW of largely baseload coal-fired generation.[467] Recent assessments by individual RTOs, the National Electricity Reliability Corporation (NERC), and others indicate that new generation and transmission expansion will be necessary to maintain regional reliability standards under this new paradigm. Without this expansion, the CPP would result in widespread

[466] 40 CFR Part 63, Subpart UUUUU.
[467] RIA, Section 3.7.4

reliability concerns, including the potential for blackouts. This kind of widespread service interruption, and the damages associated with it, has a significant negative impact on public health and welfare. Failing to adequately evaluate reliability impacts, or simply ignoring them, is not consistent with EPA's obligation to engage in reasoned decision-making, and renders the proposed CPP arbitrary and capricious.

### A. EPA Lacks the Tools and Expertise to Assess Transmission Reliability

NERC is the regulatory authority entrusted with ensuring the reliability of the bulk power system in North America.[468] NERC's authority was enhanced following the 2003 blackout that interrupted electric service throughout the northeastern U.S. and parts of Canada. While the public most often associates service interruptions with dramatic weather events, the regular aging of transmission infrastructure, and relatively minor incidents resulting in loss of load or generation can disrupt the operation of the power grid, must be planned for and considered. This is a challenge even under business-as-usual scenarios. The changes contemplated as part of the CPP presents a multitude of uncertainties and complications that increase the risk of extensive disruptions to the grid.

Computer models are maintained per NERC requirements by utilities and RTOs/ISOs that represent intricacies of the physical transmission grid and its complex operation. These models are used to assess reliability by simulating the electrical performance of the grid during real-time operations, as well as to evaluate contingencies, and to plan potential future operating scenarios. These assessments help to identify conditions that may result in violations of reliability standards, and allow utilities to identify the measures necessary to mitigate potential reliability issues before they arise.

The analyses used to determine reliability impacts are commonly known as load power flow studies and stability studies. These analyses are performed to ensure that the grid operates within its physical and electrical limitations. Power flow studies balance supply and demand, and assess whether or not the power carrying capacity of lines and equipment is exceeded, and if the resulting voltages remain within specified voltage standards. Violations of these standards cannot be ignored, because sustained operation outside of the voltage thresholds will result in

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[468] FPA

loss of load or broad system outages. In the most severe cases, the models cannot solve, which is an indication of severe issues and a high risk for a major blackout.

NERC standard TPL-001-4 governs the analysis that must be performed by transmission planners (e.g., utilities) and planning coordinators (e.g., RTOs or other NERC-approved Regional Entities) to evaluate reliability on near-term and long-term bases.[469] This standard specifically states that the analysis must consider a number of anticipated factors, including load forecasts, expected service dates of new transmission facilities, reactive resource capabilities, and generation additions, retirements, or other dispatch scenarios. Each building block within the proposed CPP has a tremendous effect on one or more of these factors. NERC, transmission planners, and planning coordinators will therefore all be required to perform short –term and long-term analyses to determine the reliability impact of the proposal.

NERC has already confirmed this conclusion. In its preliminary review of the CPP, released on November 5, 2014, NERC identified several aspects of the CPP that impact grid reliability and require further analysis.[470] Specifically, NERC identified the projected changes in generation resources, and the increased reliance on renewable resources, concentration of particular types of generating resources (NGCC) as aspects of the proposed CPP that will strain essential reliability services and require electric transmission expansion. NERC also noted that more time is needed to evaluate and implement necessary grid reliability enhancements and recommended that flexibility mechanisms be available to sustain reliability during the transition.[471] NERC recommended that it continue to assess the reliability implications of the proposed CPP, and that regional and multi-regional industry planning groups and

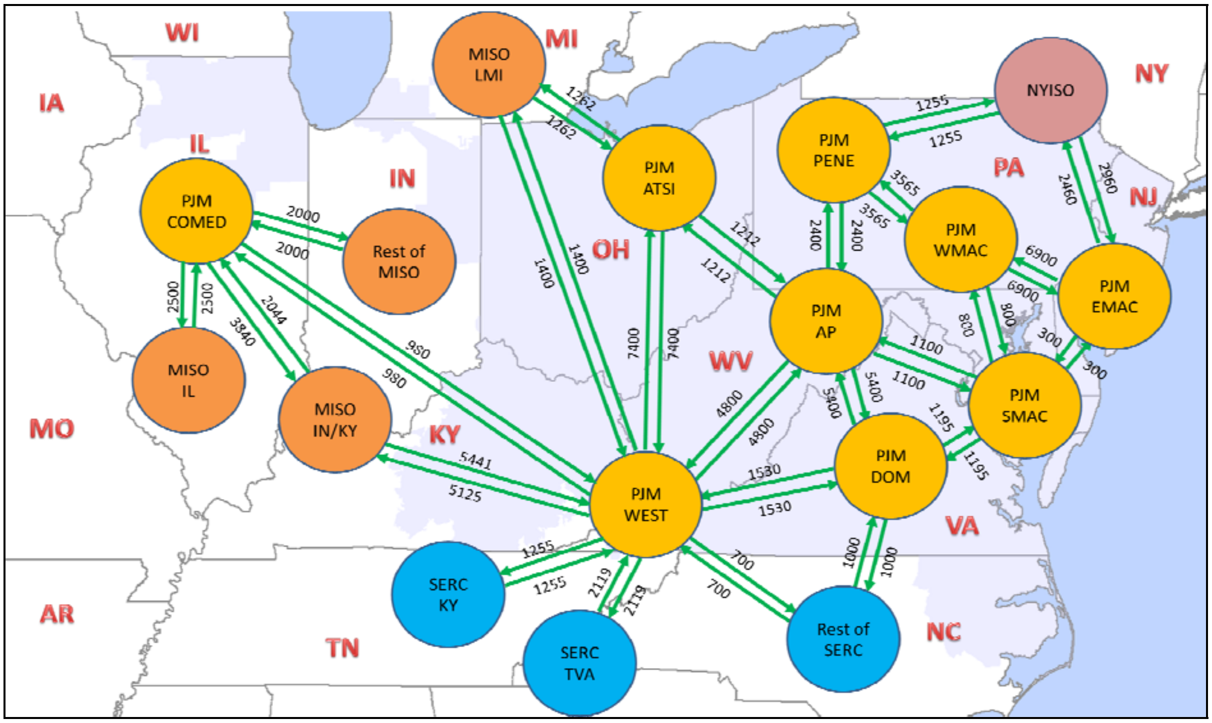
In contrast to the evaluation provided by NERC, EPA released an 11-page technical support document entitled "Resource Adequacy and Reliability Analysis" in June 2014. According to EPA, for this analysis it utilized the Integrated Planning Model ("IPM") to analyze "the ability to deliver the resources to the loads, such that the overall power grid remains stable."[472] However, IPM is an economic model that is not suited to analyzing reliability.

[469]www.nerc.com/files/TPL-001-4.pdf
[470]www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf
[471] Id at p.2.
[472] "Technical Support Document: Resource Adequacy and Reliability Analysis" USEPA. June 2014. p.1

In its description of the model, EPA states, "IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints."[473] However, the IPM model is not capable of assessing transmission reliability because, as EPA admits, "Within each model region, IPM *assumes* that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region."[474] In other words, EPA suggests there will be no impact to the transmission grid inside the regions, despite dramatically altering the generation resources within them.

EPA's analysis is merely an economic assessment that does not consider reliability impacts or NERC standards. In IPM, as in many economic models, the transmission system is equalized into large "pipes" providing a gross representation of the power transfer capability between "bubbles", or broad regions (typically RTO or utility regions). The IPM model utilized by EPA includes just 64 regions to represent over 16,000 electric transmission substations and over 450,000 circuit miles of transmission lines. This can be appropriate for high-level economic assessments, but should not be mistaken for a model that can be used to assess transmission reliability. The figure below is a depiction of the IPM economic model's representation of the transmission system.

[473] Id.
[474] Id. p.2. (emphasis added.)




**PJM Transmission According to the EPA Model**

Economic models are used to estimate values like production costs, fuel consumption, capacity factors, emissions and emission costs. An economic model does not take into consideration the voltage/reactive power requirements of the transmission grid or the full range of possible contingency events. Unlike a load power flow analysis, only a small number of outage events are considered. Consequently, the results of economic analyses cannot be used to determine reliability impacts, nor should they be considered a substitute for load power flow or stability studies.

EPA, its own words, merely assumed that adequate transmission capacity would be available to deliver resources seamlessly and reliably.[475] However, this assumption may not even be valid for the system that will exists in 2016, after all MATS retirements have occurred, and certainly cannot be assumed to be the case once all other recommended changes introduced by the CPP take place.

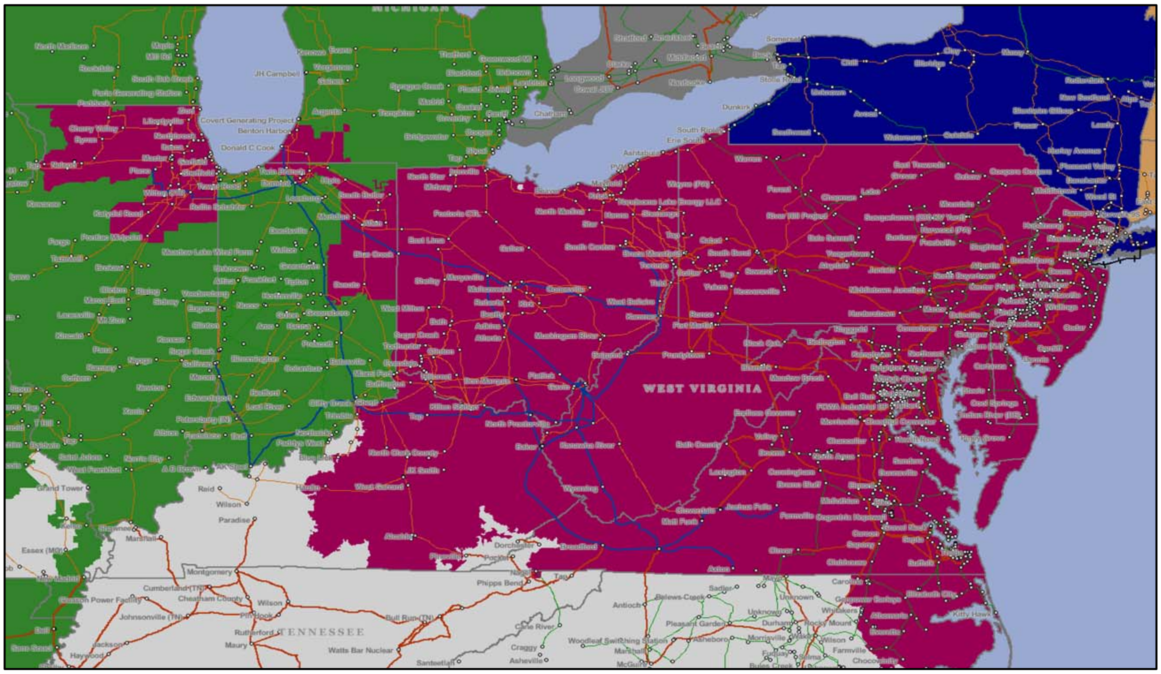
[475] *Resource Adequacy and Reliability Analysis*, p. 2.

## B. AEP and Industry Analyses Demonstrate Real Reliability Concerns

AEP has performed preliminary power flow analyses for the transmission systems in PJM and SPP based on EPA's modeled unit retirements in 2020. These studies identified severe, widespread reliability concerns in both regions.[476] The problems consist of thermal overloads, low voltages, and voltage collapse leading to cascading outages. The study results are likely to be conservative, as they did not include an analysis of inter-regional impacts, or the effects of adding substantial amounts of new renewable generation. It is anticipated that the reliability issues identified would require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation, and to support the dispatch of the system in a manner significantly different from historical operations.

As mentioned, NERC and RTOs have echoed the concerns AEP's analysis has demonstrated. In SPP's reliability assessment published on October 9, 2014, their study findings "…make it very clear that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions if EPA's projected generator retirements occur."[477] Additionally, MISO's recent assessment uncovered hundreds of non-converged (unsolved) contingencies that indicate severe reliability violations.[478] The figure below is the actual transmission system that must be evaluated for reliability purposes, and can which was used, along with the proper tools, in performing AEP's analysis and those performed by SPP.

[476] See model outputs in presentation attached as Appendix E.
[477] www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf
[478]www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20141112/20141112%20PAC%20Item%2002b%20Preliminary%20Assessment%20of%20Transmission%20Reliability%20Impacts.pdf




**The Actual PJM Transmission Grid (230 kV and above only)**

AEP's reliability analysis that shows there are significant reliability problems *within* many of the 64 IPM model regions. Additionally, the assumed ratings of the interfaces ("pipes") between the IPM regions are negatively impacted by the changes to the generation fleet. The method in which these interface ratings are established using power flow models, and often they are limited by voltage limitations as opposed to transmission line capacity. AEP's analysis shows that the capacity of key interfaces within PJM could be reduced by as much as 20% due to a reduction in voltage support following retirement of coal generating plants. Thus, EPA's assumption that transmission is adequate within or between regions is flawed and unsubstantiated.

### C. CPP Compliance Plans Are Not Viable without a Regional Transmission Analysis

EPA provides only scant acknowledgement of potential reliability issues when it states "Although there can be local grid reliability issues in replacing some units, these can be managed within the normal reliability planning and management time frames provided by the flexible resource options and time frames in the rule."[479] EPA has provided no analysis to validate this

[479] *Resource Adequacy and Reliability Analysis, p. 5*

claim, and completely ignores the reality that developing the transmission necessary to address reliability in time to achieve the reductions EPA assumes can be fully implemented by 2020 (those associated with building blocks 1 and 2) is not achievable.

In addition, the current CPP is predicated upon state-specific plans. However, the interconnected electric power system functions as a single, large, dynamic machine – extending thousands of miles. Any modifications to electric generation or transmission in one state will inevitably impact surrounding states. Therefore it is imperative that reliability analyses be performed, at a minimum, by RTOs and other regional entities, on state plans, and on the comprehensive collection of plans that will impact the reliability of the electric grid. It will be impossible for states like Indiana, Michigan, Arkansas, Texas, Kentucky, and Louisiana, for example, that have facilities in multiple RTOs, to develop a compliance plan without interregional coordination.

The CPP will force such significant changes to the electric supply that a comprehensive assessment of reliability on a regional and interregional basis should be mandated. Additionally, the time required to determine the generation scenarios, perform the assessments, and determine solutions must be factored into the time line for development, submission, and approval of state plans. Accommodations must then be made that will allow time to construct necessary transmission projects before reliability is threatened. Only by performing a comprehensive transmission assessment prior to approval of state plans will it be possible to identify potential reliability threats, and the measures necessary to address them. However, EPA must then provide the time necessary to develop the infrastructure that will be required to support the transformation envisioned by the proposed CPP.

**D. Interim Goals Incompatible with Transmission Infrastructure Requirements**

The EPA technical support document related to transmission adequacy and reliability states that:

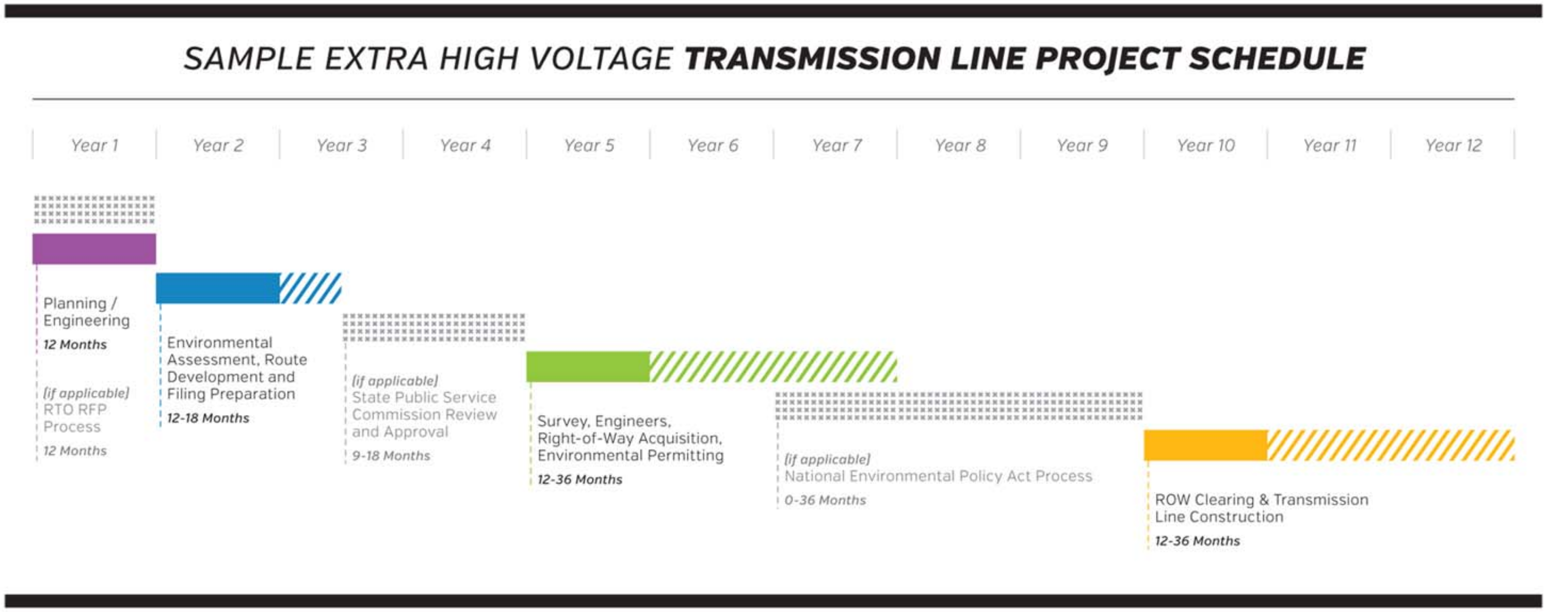
> Although not the focus of this document, it is important to recognize that this proposal provides flexibility in the context of state plan development that preserves the ability of responsible authorities to maintain electric reliability. For example, relevant planning authorities (such as ISOs and RTOs) may consult with states during the formulation of a state plan. ISOs and RTOs have also expressed interest in discussing the facilitation of emission control requirements under multi-state approaches. The flexibility of meeting the state goal over time also allows short-term variation in $CO_2$ emissions that may occur

> as certain generators run for short periods of time to maintain system reliability. While not discussed further here, these facts further support this document's demonstration that the implementation of this rule can be achieved without undermining resource adequacy or reliability.[480]

However, the reality of the situation is that the combination of targets and timelines removes any level of flexibility EPA purports to have included in the plan. Given EPA's assumptions on the retirements that would occur by 2020, it would be impossible to plan, engineer, site and construct transmission is this time frame that would provide for reliable operation of the grid.

Time lines currently contemplated for compliance are simply misaligned with transmission realities. Implementation of approved state plans will take time, as will potential mitigation measures to address unacceptable system conditions to accommodate retirements. The identification of new transmission needs, engineering, siting and construction will take anywhere from 5 to 10 years following development of the compliance plans. Figure 3 below highlights the major components of a typical transmission line project schedule.

[480] Id. p. 1.




**Sample Transmission Project Schedule**

A transmission project lifecycle can vary significantly depending upon the type of project and where it is being built. The nature of the project (for example, its voltage and length), trigger different regulatory processes in different areas. Some, but not all, states review applications and issue permits for construction. Environmental issues, necessary permits and crossing public lands widely affect the process. Additionally, projects that require a National Environmental Policy Act review can plan on adding one to three years, or more, to the process. In AEP's own experience, a 90-mile line can take 16 years to complete.

As indicated previously, reliability studies must accompany the CPP's implementation and be incorporated into the compliance time frames. One of the few studies to date that could be considered comparable in scope to that required to assess the impact of EPA's CPP is the Eastern Interconnection Planning Collaborative (EIPC). This DOE-sponsored initiative was a first-of-its-kind effort to involve planning authorities in the Eastern Interconnection to model the impacts of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. Even this analysis, which did not consider the full range of NERC reliability standards, took over two years to complete, and ultimately did not result in an actionable plan.

Even after transmission requirements are identified, developers must be given the authority to construct quickly. The time line to plan and build upgrades to the transmission infrastructure will extend several years beyond the date resource plans are identified, and the current time lines for compliance with the CPP are insufficient for the necessary infrastructure to be built. Accomplishing this may require policy changes that sanction RTOs and other planning authorities to take action by approving necessary solutions sufficiently in advance of compliance deadlines and streamline siting and permitting activities.

Finally, the magnitude of the necessary transmission grid enhancements is expected to be substantial. However these grid enhancements cannot all be constructed at the same time. The new transmission infrastructure will need to be staged and constructed in a manner that allows the grid operators to schedule necessary facility outages while continuing to maintain reliable operations and keep the lights on. The need to stage the construction activities will increase the time frame required to fully implement the CPP.

### E. Assumptions for Renewable Expansion Must Also Consider Transmission Requirements

Another aspect of the CPP that affects transmission is the integration of renewable resources. While this aspect was not directly considered as part of AEP's reliability analysis, it is well documented that connection and reliable delivery of new renewable resources requires transmission expansion. Even if states were to rely on existing RPS requirements to fulfill obligations under the CPP, the transmission grid is ill equipped to meet those objectives. PJM recently hired GE Energy Consulting to perform a renewable integration study for the region[481]. This study indicated the need for at least $3.7 billion in transmission upgrades to support a 14% regional RPS, and this figure could reach $13.7 billion under higher penetration scenarios. While these figures may pale in comparison to the total cost of implementing the CPP, the reality is that these transmission facilities would be in addition to the upgrades required to mitigate reliability impacts of coal unit retirements. Since much of the renewable generation capacity is located in remote locations far from load centers, much this infrastructure would be new facilities that require significant time to plan, permit, site, and construct.

### F. Transmission Recommendations

A robust and adaptable transmission grid is essential to diversifying the generation portfolio and accommodating large changes to generation resources. The CPP will force significant changes to the electric generating plants, which will have clear ramifications on a transmission system designed for an entirely different supply paradigm. Transmission modernization can provide significant benefits, and should be considered an essential and complimentary element of the CPP.

For states to adequately develop an implementation plan, they will need to evaluate long-term options that involve unit retirements, multi-year contracts, e.g., power purchase agreements, or the requirement for the utilities to build new power plants. These decisions will drive the need for enhancements to the transmission grid and, conversely, transmission needs may affect states' decisions on generation resources. If enacted, the following recommendations are considered the minimum steps necessary to facilitate the evolution of the transmission system to accommodate these complex regulations:

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[481] http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx

- A comprehensive assessment of reliability on a regional and interregional basis should be mandated and included as part of the CPP. RTOs, under the guidance of NERC, should commission detailed reliability studies to evaluate the impacts of both retiring generation and integration of new generation resources.
- RTOs should facilitate development of transmission upgrades necessary to sustain reliability and ensure the integrity of the transmission grid is maintained during the implementation period.
- The time required to determine the generation scenarios, perform the detailed analytical assessments, and identify the required grid enhancements and construct the necessary transmission infrastructure must be factored into the time line for compliance to ensure reliability is not threatened.

## XI. Assessment of Regulatory Impact Analysis

EPA's Regulatory Impact Analysis ("RIA") of the proposed rule does not provide an adequate administrative record to allow for proper evaluation of the proposed rule and subsequent public comment. Furthermore, the methodology for assessing both costs and benefits is deeply flawed where information is present to be evaluated. The following areas have been identified as having either inadequate and incomplete information or information which was misinterpreted and/or misused within EPA's assessment of the potential cost, impacts and benefits of the proposed rule:

- Lack of Information on State Compliance Actions
- Conflicts Between Results and Purported BSER Elements
- Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs
- Incomplete Assessment of Employment Impacts
- Improper Treatment of Energy Efficiency
- Improper Use of Social Cost of Carbon
- Incomplete Assessment of Alternative Futures
- Misrepresentation of Energy Efficiency Expenditures/Costs

In light of these inadequacies, EPA should withdraw the current rule and re-propose at a later date, while addressing the previous legal and technical comments, in addition to the comments provided below.

### A. Lack of Information on State Compliance Actions

The Integrated Planning Model (IPM) was used to support the RIA, however the IPM output files provided by EPA do not allow for a proper evaluation of the suite of measures that states and affected sources are projected to utilize under the proposed rule. EPA has provided the IPM "parsed" model output files only for one select model compliance year for each of the cases run. This does not allow for a full evaluation of state-by-state compliance actions across the full timeline the proposal encompasses. Furthermore, the model year provided is not consistent between the cases run. Additionally, the outputs for the IPM model run consisting of only building blocks 1 and 2 appears to be based on a single integrated model compliance year which does not allow for proper assessment of the emission caps as utilized by EPA. Full outputs and documentation are critical to the evaluation of the rule, particularly as the state agencies responsible for rule administration do not possess the tools or resources to assess potential electric sector compliance strategies.

### B. Conflicts Between Results and Purported BSER elements

From the IPM results that are publically available, there are considerable inconsistencies between the modeled outcomes and what EPA has suggested as the BSER for the "building block" approach to calculating state goals. As a prominent example, EPA concludes that the existing NGCC fleet will only achieve annual capacity factors of 50-57 percent while the BSER determination suggests that 70 percent capacity factor is achievable. As the IPM model is a least-cost optimization, the fact that NGCC units do not reach 70 percent capacity factor in aggregate suggests there are unaccounted for significant economic and or physical barriers to increased utilization. This calls into question the robustness of EPA's initial BSER determination.

Another example of an inconsistency between the IPM modeled outcomes and building block determinations is in the deployment of renewable energy resources. EPA's modeling suggests a relatively small amount of new renewable energy development; for wind energy, the dominant source of renewable energy additions, there is only an 11 to 12 percent increase in generation in the policy cases for Option 1, as compared to the base case. Additionally, the renewable energy capacity additions appear to be centered in a few select states and regions, which is contrary to the view that renewable energy additions are cost effective across all states. In light of these inconsistencies, EPA should revise its BSER determination to reflect the amounts of renewable energy that are economically justified.

### C. Incomplete and Improper Assessment of Compliance Actions, Infrastructure Timing and Costs

EPA has not provided a proper assessment of the timing and costs of associated infrastructure needed to implement this rule within the RIA. As currently utilized, the IPM model is an optimization of economic outcomes without regard to physical or practical realities. The model improperly assumes that compliance actions related to existing generating assets and construction of new generating assets could be deployed in 2016, which would assume an even earlier compliance evaluation and planning process. This is well in advance of when state plans would be developed, and does not consider the time necessary to put in place accompanying regulatory, legislative and compliance decisions. It is thus completely inconsistent with how the electric system is planned and managed.

EPA has a statutory duty to "tak[e] into account the cost of achieving such reduction" when determining the "best system of emission reduction."[482] The most centrally relevant costs are the costs to the existing sources required to make the emission reductions mandated under section 111(d). EPA has failed to identify, much less consider, those costs. Instead, EPA has estimated macroeconomic net costs to the entire nation. Under EPA's proposal, virtually all of the reductions in $CO_2$ emissions from affected EGUs come from reduced utilization of coal-fired EGUs. EPA must, at a minimum, determine the diminution in asset value to the owners of those existing sources, and the local and regional economic disruption and unemployment that would result from the proposal.

As an example, under its assessment of Option 1, EPA projects that an incremental 41 to 44 GW of generation will be taken offline in 2016 relative to the Base Case. Many of the units projected to retire are currently in the process of making multi-million dollar investments in emission controls to comply with MATS. EPA has therefore assumed billions of dollars of stranded investment associated with current retrofit projects and existing plant, property and equipment, which may not be fully depreciated. In regulated jurisdictions, these costs will be passed on to customers in the form of higher rates. In deregulated jurisdictions, these stranded investments will result in a loss of shareholder value.

In addition, EPA has failed to identify and consider the costs of the proposed transformation of the existing electricity systems, such as additional transmission facilities, additional natural gas pipeline capacity, additional transmission support capacity, additional financing costs of intermittently used generating capacity, and additional maintenance, repair and replacement due to increased ramping up and down of dispatchable generation. It is implausible to interpret the mandate to consider cost in section 111(d) as excluding the costs pinpointed on specific existing sources and specific local and regional economic disruption and unemployment. EPA's proposal is deficient and arbitrary in its omission of: 1) any analysis of the direct cost impacts to owners of existing coal-fired EGUs that would be expected or forced to shut down or reduce utilization; and 2) any analysis of the full costs of ensuring a reliable bulk power supply system in a rapid transition to lower carbon and intermittent electricity generation.

[482] 42 U.S.C. § 7411(a)(1).

EPA uses a separate Retail Price Module developed by ICF to estimate the impacts of the rule on retail electricity rates. However, it is unclear that this model incorporates stranded costs or ancillary transmission and other investment costs into its projections of electricity rates impacts. Stranded costs are capital expenses made by cost-of-service based utilities that are not fully recovered from customers by the end of a facility's useful life. As these plants would be prematurely deemed uneconomic, many of these plants would have associated capital costs that have not been fully recovered from ratepayers. Thus, ratepayers would still be required to pay the costs associated with these retired units in addition to the costs of any other measures that would have to be deployed in response to the rule. These consumer costs must be included in projections of rate impacts.

Notwithstanding the improper accounting of costs, there still remains the fact that compliance decisions related to existing assets will not be made until well after state compliance plans are approved. In the case of multi-state plans with one-year extensions at the state level, this approval could come mid-2019 or later. This is completely inconsistent with the assumption in EPA's modeling that compliance decisions related to both the disposition of existing assets and investment in new assets could be made to effectuate changes in the 2016 generating mix. A similar argument applies to the construction of new renewable energy efficiency measures and energy efficiency programs. Additional comments on this subject are also included within the Implementation section of AEP's comments.

The economic selection of unit retirements and new generation in the 2016 model year artificially skews the cost assessment of the proposal lower by assuming premature economic actions without a firm regulatory basis. Economic compliance decisions cannot be made and will not be made until well after state plans are approved. Due to this fact, in the IPM model assumptions, EPA must assume that any changes in the electric generating mix cannot occur until at least 2020 and then factor in the relevant development timelines for the various generating technologies. Using this realistic assumption for technology deployment would thereby limit any changes in the electric generation mix until well into next decade, which is reasonable given the timeline for state plan development, regulatory action and compliance determinations.

EPA has also not included any assessment of the need for firm gas delivery to support higher utilization of NGCC units. As units would be required to run additional hours to replace higher emitting generating sources, there would be increased hours of the year in which they would need delivered gas. However, in peak months, natural gas may not be available without a firm delivery contract. A firm delivery contract results in a higher delivered gas price, as the gas must be paid for whether used or not. This cost also needs to be factored into the cost assessment.

### D. Incomplete Assessment of Employment Impacts

EPA's assessment of labor impacts ignores the largest labor impacts, which are the indirect jobs impacted as a result of higher energy costs. Higher electricity rates will arise in response to this proposal, discounting EPA's improper assumptions regarding energy efficiency and other factual modeling errors, as generators will be forced to internalize carbon costs and invest in compliance strategies that would otherwise be uneconomic absent the proposed rule. Higher natural gas prices will also be realized as electric generators consume more natural gas, driving domestic natural gas demand higher. Higher natural gas prices and electric rates will result in the economic dislocation of some industries, particularly those industries that are energy intensive, as they are unable to fully pass thru the higher cost of electricity and natural gas to their consumers and customers. This economic disruption will result in businesses curtailing output or relocating, with the loss of employment and tax income. EPA must consider these indirect job impacts in the RIA.

### E. Improper Treatment of Energy Efficiency

The methodology used to evaluate the cost and benefits of energy efficiency (EE) are completely disjointed from a practical and economic reality. For purposes of cost-benefit analysis, EPA's assumptions on EE were "[hard wired] into the illustrative compliance scenarios. This approach is taken because the EPA has determined, as discussed previously, that EE is cost-effective at the established EE goal levels."[483] However, notwithstanding AEP's objections to the EE methodology, if the projected levels of energy efficiency are deemed to be exogenously economic, they should also be included in the Base Case projection of electric demand as these activities should occur organically absent this rulemaking and thus should already be factored into the electric load forecast. EPA makes no effort to rationalize why either EPA or EIA has not

[483] *Technical Support Document on GHG Abatement Measures,* at 5-49.

included these types of projections within the reference load forecast or what EPA models as a "base case."

The proposed rule does not require states to target any specific level of energy efficiency, nor is it within EPA's authority to require a set level of efficiency, the inclusion of the energy efficiency measures only in the policy cases artificially skews the costs of the program downward by assuming less generation is needed to meet electric demand and that avoided costs are greater than EE program costs. As EPA has reached a conclusion that the proposed levels of EE are economic under prevailing market conditions, EE measures must be included in both the base case and policy cases to ensure a proper, fair and transparent assessment of costs that are directly attributable to this proposal.

**F. Improper Use of Social Cost of Carbon**

EPA uses the Social Cost of Carbon (SCC) to characterize potential carbon benefits associated with the proposed rule, even though it is widely acknowledged that these cost estimates are inaccurate, uncertain, and highly speculative. EPA acknowledges in the RIA that "any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional."[484] As such, these calculations cannot form the basis of an adequate RIA. Additionally, according to guidance provided by the Office of Management and Budget (OMB), costs and benefits must be examined on a domestic, not global, basis. The current methodology for assigning a cost to carbon is based on a global value and therefore is both inconsistent with OMB guidance and EPA assessments of costs, which are only on a U.S. basis. As a result, EPA is offering an "apples-to-oranges" comparison of costs and benefits within the RIA.

As an example of how the flawed geographic scope of cost-benefit evaluation skews the results, one can examine the conclusions reached through EPA's IPM modeling of the rule. As projected by EPA's modeling, domestic coal prices will decline and natural gas prices will rise as a result of the proposed rule. Basic economics suggests that this change in prices would encourage increased exports of coal due to its lower cost basis and decreased exports of natural gas due to its higher cost basis. Because of this likely change in exports, international $CO_2$

[484] "RIA for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants." USEPA. June 2014. p. 182.

emissions will rise through increased international use of coal and decreased international use of natural gas, thus diminishing the purported benefits of the rule. Additionally, increased electricity and natural gas prices as a result of the rule could shift more manufacturing overseas to less efficient facilities to take advantage of lower energy costs, which could also result in increased $CO_2$ emissions. These potential increases in global $CO_2$ emissions, which would result in carbon costs, have not been quantified in any form, even though the benefits of the rule are calculated on a global basis. Due to this inherent and incorrect dichotomy, EPA must recalculate and evaluate any climate "benefits" associated with this proposal solely on the basis of domestic carbon value.

AEP also has considerable other concerns with the current methodology used to develop the Social Cost of Carbon (SCC) and has previously submitted detailed comments on the development of SCC values and their use. These comments are attached as Appendix F to this document.

**G. Incomplete Assessment of Alternative Futures**

EPA has not adequately accounted for the potential impacts of the proposed rule under a full range of possible future market conditions, effectively hiding the true potential costs of the proposed rule. Instead of robust scenario analysis, which would incorporate plausible alternative assumptions, EPA has overly relied upon "one-off" calculations and comparisons in making key determinations as to cos- effectiveness of technologies and programs. Policymakers and the general public need to be fully informed of the potential costs of this proposed rule through a comprehensive and well-informed analysis.

EPA has used a single model run in its analysis of options 1 & 2. However, while EPA conducted sensitivity analyses on a number of the assumptions going into the BSER determinations in an one-off approach, there was no effort to test the robustness of assumptions within the regulatory impact analysis of the rule. As the proposal assumes that BSER measures are available to the same extent they are used in the calculation of state targets, there is no proper assessment of the potential implications of one or more of the "building blocks" being either less available in quantity or less economic. As the BSER determination is structured on the "best system," unavailability of one of the building blocks would leave a state or region with limited options to reduce emissions elsewhere. EPA needs to provide alternative scenarios assuming some variance of the achievable rate of energy efficiency, heat rate improvements, and renewable developments, to paint a full picture of the potential costs of this proposed regulation.

It has been well understood and documented within the electric power sector that natural gas supply and prices play a pivotal role in determining both the current and projected future electricity mix, as well as electricity costs. EIA, whom EPA relies upon for a number of key data points, routinely produces alternative scenarios in its Annual Energy Outlook to examine some of these alternative futures given the importance. However, EPA has not evaluated any variance in natural gas supply or pricing under this proposal. This variable also needs to be further explored through sensitivity analysis and reporting of potential costs.

**H. Misrepresentation of Energy Efficiency Expenditures/Costs**

EPA misrepresents Energy Efficiency (EE) expenditures within the RIA by choosing to report and tabulate annualized EE costs in-lieu of first-year EE costs. As a result of the error, the total cost of the proposed rule is dramatically understated in both annual and present value terms. Energy efficient programs are typically funded on the basis of O&M expenditures for utility program costs and out-of-pocket expense for participant costs. As EE utility program costs are typically expensed, not capitalized within a rate-base, a first-year cost is the appropriate measure to evaluate the true cost, as this is the cost that directly flows to customer rates. Furthermore, participant costs are typically not financed, but rather represent a one-time out-of-pocket expenditure. Even to the extent some programs are financeable; the lending term is likely to be significantly less than the 20 year measure life assumed by EPA. As such, both participant and utility costs should be reported on an annual first-year cost basis.

As a result of EPA relying on annualized EE costs, the annual cost of the Clean Power Plan is dramatically understated in the early portions of the program, by more than $20 billion and almost $15 billion in 2020 and 2025, respectively. This has an enormous impact on the overall cost analysis for the proposed rule as the difference in cost reporting is accentuated under a calculation of present value cost. Use of annualized EE costs results in enormous discounting of total EE costs given an assumed 20 year EE measure life. Proper actuarial treatment would result in significantly higher present value costs as first-year costs would be discounted less to the present year.

In the calculation of retail rate impacts EPA appropriately recognizes utility program costs on a first-year cost basis. This first-year cost basis also needs to be applied to EE programs within the total cost assessment to allow for a proper assessment of the proposed rule's costs and benefits.

### I. EPA must consider costs associated with transmission improvements required to implement the proposed rule and maintain reliability

As discussed in Section X above, EPA failed to conduct an adequate reliability analysis to determine the extent of potential improvements that are needed to existing transmission system in order to maintain reliability with the implementation of the proposed rule. Based on AEP modeling and concerns express by regional transmission organizations and NERC, the amount of improvements to the transmission grid may be extensive. As summarized in Appendix E, AEP's analysis indicates up to $2 billion in potential improvements may be necessary on the AEP transmission system alone as a result of the proposed rule. EPA must thoroughly evaluate and weigh costs associated with transmission upgrades in the RIA for the proposed rule.

## XII. Miscellaneous

### A. EPA Cannot Regulate Sources in a Category Subject to a Standard Under Section 112.

AEP adopts by reference, as if fully set forth herein, the arguments made in comments submitted by UARG, EEI, and 17 states' Attorneys General,[485] that the clear language of section 111(d) prohibits EPA from regulating emissions under that section when the "source category ... is regulated under section [112]."[486] EPA admits that a literal reading of the codified statute has this result,[487] but relies on a conforming amendment that was excluded from the code as justification for departing from the plain language of the law. EPA cites no support for this unique method of construing conflicting provisions of amendments made to a complex piece of legislation, and none exists. Instead, the conforming amendment should be disregarded, and the substantive amendment reflected in the U.S. Code should be given full effect.[488] As noted in UARG's comments, the conflicting amendments here do not create "ambiguity," they create conflict, and conflict can only be resolved by legislative choices, that is, by Congress.[489] Here Congress clearly acted by later passing the House bill, which contains the codified language prohibiting duplicative regulation of sources already regulated under section 112. Having made its choice to regulate EGUs under section 112,[490] EPA cannot now assert authority to regulate the same sources under section 111(d).

### B. The Proposed Guidelines Constitute Uncompensated Takings.

For all of the reasons set forth above in Section IV, EPA cannot require reduced utilization or shutdown of existing EGUs as a "standard of performance" under section 111. However, to the extent that the proposed guidelines would result in the shutdown or reduced utilization of an existing unit with remaining useful life, particularly those units that have made substantial investments to comply with other recent rulemakings from the Administrator, the proposal would constitute an unlawful taking without just compensation, prohibited by the Fifth Amendment to the U.S. Constitution. The economic value of an EGU lies in its ability to generate electricity.

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[485] Comment from the Attorneys General of the States of Oklahoma, West Virginia, Nebraska, Alabama, Florida, Georgia, Indiana, Kansas, Louisiana, Michigan, Montana, North Dakota, Ohio, South Carolina, South Dakota, Utah and Wyoming, Docket No. EPA-HQ-OAR-2013-0602, submitted November 25, 2014.
[486] 42 U.S.C. § 7411(d)(1)(A)(i).
[487] *Legal Memorandum* at p. 26.
[488] *See, e.g.,American Petroleum Inst. V. SEC,* 714 F.3d 1329, 1336-1337 (D.C. Cir. 2013);
[489] *Scialabba v. Cuella de Osorio*, 134 S.Ct. 2191, 2214 (Roberts, C.J. concurring) (2014).
[490] 40 CFR Part 63, Subpart UUUUU.

The government must protect the investment-backed expectations that are embodied in the concept of "property," and provide just compensation if regulation goes so far as to rob citizens of the beneficial use of their property.[491] AEP incorporates by reference, as if fully set forth herein, the arguments made by UARG regarding this issue.

### C. EPA Cannot Simultaneously Regulate Units Under Sections 111(b) and (d).

EPA proposes that units that become "modified" and therefore "new" sources after a state plan is adopted and goes into effect will remain subject to the requirements of the state plan, and at the same time be required to comply with the recently proposed standards under section 111(b). This result is precluded by the plain language of the statute, which contains definitions for "new" and "existing" sources that are mutually exclusive.[492] EPA's proposal would result in duplicative and overly burdensome regulation for the sources and confusion regarding the obligations of state permitting authorities. This purported "ambiguity" arises solely as a result of EPA's decision to invert the nature of the proposed standards, seeking far more aggressive emission reductions from existing sources than those that would apply if a source became "new" as a result of a modification. There is no basis for EPA's duplicative regulatory proposal, and it conflicts with the clear language of the statue and is invalid.

### D. EPA's Proposal Omits Critical Information About Title V Requirements.

EPA's proposal omits critical information about the Title V requirements applicable to "affected entities" potentially included in state 111(d) plans, contrary to EPA's Title V regulations. The definition of "applicable requirement" for Title V permitting purposes includes "any standard or other requirement under section 111 of the Act, including section 111(d)."[493] The Title V regulations require a Title V permit for "[a]ny source, *including an area source*, subject to a standard, limitation, or other requirement under section 111 of the Act."[494] The regulations then provide: "In the case of non-major sources subject to a standard or other requirement under ... section 111 ... of the Act after July 21, 1992 . . , the Administrator will

[491] *Lingle v. Chevron USA, Inc.,* 544 U.S. 528,537 (2005); *Lucas v. South Carolina Coastal Council,* 505 U.S. 1003, 1019 (1992).
[492] 42 U.S.C. § 7411(a)(2) and (6).
[493] 40 C.F.R. § 70.2.
[494] 40 C.F.R. § 70.3(a)(2).

determine whether to exempt any or all such applicable sources from the requirement to obtain a part 70 permit at the time that the new standard is promulgated."[495]

EPA has not made any proposed determination of whether to exempt any or all non-major (area source) "compliance entities" subject to a standard or other requirement under the proposed Clean Power Plan from the duty to obtain a Title V permit. However, as discussed above, it is clear that making certain types of entities "compliance entities" results in an unauthorized expansion of EPA's authority, and will present unresolvable issues for state permitting authorities. The applicability or non-applicability of Title V permitting requirements also determines the enforcement mechanisms available to the states for section 111(d) plan requirements applicable to "compliance entities," and illustrates the absurd results that would follow from making the state itself, other governmental entities, or non-emitting generators subject to the enforcement provisions of the Title V permitting program. To the extent EPA continues to rely on its "portfolio approach" to developing section 111(d) plans, EPA's final rule must clarify the application of Title V's permitting requirements to "compliance entities," and avoid the absurd results that would ensue if section 111(d) were interpreted to encompass a broad range of entities far beyond the "affected facilities" that are within the listed source categories and can legitimately be subject to a 111(b) standard.

### E. EPA Failed to Consider the Implications of Proposed Changes to the Ozone Standard.

The preamble to EPA's proposed section 111(d) rulemaking contains a discussion of the implications of other EPA rules on the proposal.[496] However, the proposal and its basis and purpose are completely devoid of any mention of another rule, the proposed revision to the ozone NAAQS, due to be published the same day comments are due on the section 111(d) proposal. EPA is under a court order to propose appropriate revisions to the current ozone standard (75 ppb, set in 2008) by December 1, 2014. The OAQPS August 2014 Policy Assessment finds the current standard insufficiently protective and recommends a more stringent standard in the range of 60 to 70 ppb.[497]

[495] 40 C.F.R § 70.3(b)(2).
[496] *See* 79 Fed. Reg. at 34,928 - 34,931.
[497] *See* EPA., Office of Air and Radiation, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards, at ES-5 (Aug. 2014) (*available at* www.epa.gov/ttn/naaqs/standards/ozone/data/20140829pa.pdf).

A more stringent ozone standard would have a material impact on the sources subject to the proposed section 111(d) rules. For example, a more stringent ozone standard would impact the timing and permitting obstacles to construction of new NGCC capacity necessary to replace dispatchable coal-fired capacity required to reduce utilization or retire as a result of the proposed section 111(d) rules and other EPA requirements, including the Mercury and Air Toxics (MATS) rule. A more stringent ozone standard would impose resource demands on states required to develop implementation plans, at the same time they must address the proposed Clean Power Plan. Also, a more stringent ozone standard could complicate the states' obligations under proposed 40 CFR § 60.5740(a)(6), to demonstrate that each emission standard in the state's §111(d) plan is "non-duplicative" with respect to an affected entity (*i.e.,* will reductions in $CO_2$ emissions or electricity demand resulting from compliance with revised ozone standards be deemed "non-duplicative"?) and would complicate States' evaluations of the optimum mix of "building blocks" for achieving the mandatory section 111(d) "state goals." However, only EPA knows the nature of its proposed revisions to the ozone standard, and the interactions between a more stringent ozone standard and its section 111(d) proposal. It is for EPA to address in the first instance the implications of a revised ozone standard on the proposed section 111(d) rules.

At a minimum, EPA should address the interactions between its proposed section 111(d) rules and any proposed revisions to the ozone standard, and provide adequate time for comment in this rulemaking on those interactions before finalizing the proposed section 111(d) rules.

### F. EPA's October 30, 2014 NODA Fails to Satisfy EPA's Obligations Under Section 307 of the CAA.

EPA's proposed rulemaking on $CO_2$ emission guidelines for existing fossil-fueled EGUs is so saturated with alternatives, and such a multiplicity of major legal interpretations and policy considerations (often inconsistent or inchoate), spanning such a vast range of inadequately analyzed data and assumptions regarding electricity planning, generation, transmission, pricing, financing, and use, that it frustrates public participation and judicial review. All things large and small are open for comment, so much so that there is not a coherent statement of basis and purpose underlying an intelligible proposed legislative rule. The very grandiosity of the proposal itself should have been a clue to EPA that its interpretation of the Clean Air Act as allowing for such widespread economic regulation has led it astray.

The June 18, 2014 proposal, for example, is accompanied by a 19-page spreadsheet titled "Listing of U.S. Environmental Protection Agency Requests for Comment."[498] The spreadsheet lists 204 separate "categories" for which EPA is requesting comments. Many of the categories float in the ether, unconnected to any proposed regulatory language or discernable consequences to the proposed BSER determination, the obligations imposed on the states, or the impact on other "affected entities." EPA solicits comment on different rationales for reaching a single conclusion, or different conclusions that could follow from a single rationale. Some issues for which comments are requested could have a material impact, or a domino effect, on some of the most basic elements of the proposed state $CO_2$ goals.

The October NODA compounds the scattershot nature of the original June proposal by introducing a whole host of new issues on which EPA solicits comment. The NODA further obscures the intelligibility of the proposed rule. EPA asks for comment on issues that could make the state goals more or less aggressive, the time deadlines more accelerated or longer, and the formula for determining compliance or noncompliance with the state goals more stringent or more malleable. EPA seeks input regarding the baseline for computing state $CO_2$ goals and the possible reformulation of state compliance criteria to include yet-to-be-constructed natural gas pipelines and new nuclear and NGCC generating capacity. The NODA simply highlights that EPA has failed to gather essential data and complete the pertinent analyses, even more than four months after the proposal, on how the proposal will impact the reliability and resiliency of the bulk power grid – matters of paramount public interest and an absolute prerequisite to reasoned decision-making.

In many ways, the June 18, 2014 notice of proposed rulemaking, even more so the October 30, 2014 NODA, is more like an advanced notice of proposed rulemaking than a notice of proposed rulemaking. Ironically, the NODA asks for comments on "the potential changes identified in this document in terms both of the rationale for these changes and their effects on the stringency of the state goals, as well as ways in which the potential changes interact with each other."[499] How could such questions remain unanswered by EPA? With so many moving parts and independent and dependent variables in EPA's proposal, how can a commenter know

[498] *See* EPA, Proposed Clean Power Plan for Existing Power Plants, Listing of U.S. Environmental Protection Agency Requests for Comment, www2.epa.gov/sites/production/files/2014-08/documents/clean-power-plan-comment-categories.pdf.
[499] 79 Fed. Reg. at 64,544, col. 2.

how they interact with each other if EPA does not? Four months after its notice of proposed rulemaking, EPA solicited comments on "ideas" (but no regulatory language) on such basic fundamentals of the proposal as "alternative approaches for the goal-setting equation and alternative uses of data in calculating the goals."[500] There are too many gaps in the data and analyses, too many unanswered questions about the underlying basis and purpose, and too many alternative rationales, conclusions, and regulatory possibilities to constitute a proper foundation for informed public participation and reasoned decision-making.

The October NODA also illustrates the extent to which EPA's proposal to transform the electricity sector is outside the zone of the Agency's core technical expertise. Without any proposed regulatory language or identification of regulatory consequences, and without any EPA analysis of the nature and effect of its proposed action on electric costs and reliability, EPA is asking for information on the "technical, engineering, and infrastructure limitations or other considerations" associated with shifting from coal-fired to NGCC generation as calculated under building block 2, and how building block 2 "may limit cost-effective options for emission reductions."[501] EPA is likewise asking for information on threshold issues such as "the time required to improve natural gas pipeline infrastructure in some states" and the need to "stop operating by 2020" even recently constructed coal-fired units, and coal-fired units for which recent significant capital investment has been made for EPA-required pollution control retrofits.[502] This is information is of utmost relevance and importance to EPA's proposal.

The concern is not that EPA is asking for this information. The concern is that EPA is not the electricity regulator, and even if it were, EPA was not ready to issue the type proposed rule it did in June without first analyzing this and other information, and then disclosing the results of that analysis in its notice of proposed rulemaking, including the data, technical evaluations, and resulting proposed regulatory language, together with a statement of its basis and purpose. EPA's failure to do so violates section 307(d) of the Clean Air Act,[503] and is unlawful and unreasonable.

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[500] 79 Fed. Reg. at 64,545, col. 2.
[501] 79 Fed. Reg. at 64546, col. 1.
[502] 79 Fed. Reg. at 64546, col. 2.
[503] 42 U.S.C. §7607(d)(3).

## XIII. Recommendations

Electricity serves as the foundation of our nation's safety, security, and prosperity. EPA must take the time to carefully consider all of the comments submitted, and to issue guidelines that strike the appropriate balance between environmental protection and economic well-being. EPA should develop and issue for comment a proposal that includes the following elements:

(1) Heat rate improvements can be cost-effective ways to reduce $CO_2$ emissions, or to mitigate increases in $CO_2$ emissions, over the life of a fossil-fueled generating unit, regardless of fuel type or unit design. However, given the inherent variability in heat rate due to duty cycles and other uncontrollable factors, and the lack of an effective real-time heat rate measurement technique, it is infeasible to establish traditional emission limitations or standards based on improved heat rates. EPA should collect sufficient information about the techniques that could potentially be adopted to varying degrees at existing units (considering costs, lack of physical space, degree of prior adoption, remaining useful life, and other factors) and formulate a proposed guideline for a work practice standard that would allow for periodic evaluation of cost-effective heat rate improvement opportunities on a unit-specific basis, that can then be integrated into regularly planned outages across the existing fleet. Such a measure would ensure sustained adoption of available efficiency improvements within the existing fleet, which is the "best system of emission reduction" for these designated facilities.

(2) Encouraging reduced utilization of certain existing units and increased utilization of others is not authorized as a "means of emission limitation" under Section 302, and is inconsistent with the authorities granted to the Federal Energy Regulatory Commission (FERC) and the regional reliability organizations under the Federal Power Act (FPA). Section 310 of the Clean Air Act clearly states that EPA's authorities cannot be interpreted in such a way as to intrude upon the implementation of security constrained economic dispatch of the bulk electric system through the mechanisms FERC has developed under the FPA. However, future emission reductions will occur through the natural aging of the existing fleet, and plans could be established based on the remaining useful life of existing units consistent with the express language of section 111(d). EPA should allow states to examine the emission reductions that will occur within the existing fleet as units near and reach the ends of their useful lives, and establish a glide path to lower total mass emissions from the existing fossil fleet. EPA should allow states to calculate the "degree of emission reduction" achieved through such a procedure, and to develop the path for reductions that is consistent with the energy and economic needs of the states. EPA has no authority to dictate arbitrary "interim" goals that the states must meet.

(3) Nothing in the Clean Air Act gives EPA the authority to specify the types of new generation resources that should be constructed to fulfill a utility's obligation to serve. This authority has been specifically reserved to the states under the FPA, and no Congress has yet passed laws to establish national renewable portfolio standards. However, EPA should allow states to examine the planned additions of renewable and other low- or non-emitting resources under existing integrated resource plans and other siting or certification requirements, and

use any approved, cost-effective resource additions as creditable emission reductions, to facilitate the transition of the existing fleet to a cleaner, more modern system.

(4) Energy efficiency targets and goals have also been used by state utility regulators and state energy resource planning agencies as a means to delay the need for additional capital-intensive base-load generating resources, and to manage peak loads. States should be given the option to take credit for these efforts if they prove to be cost-effective, and as new technologies develop. However, EPA is not an energy planning expert or rate regulator, and these measures can only be developed consistent with the reserved power of the states for retail energy rate regulation. There is no single "best practice" that can be established for all states. Each state should be allowed to incorporate its energy planning strategy into a plan under section 111(d) to the extent it determines is appropriate.

Like the Clean Power Plan, the four recommendations listed above are not mandatory or federally enforceable requirements; they are merely guidelines to be used by the states as one of many factors that will contribute to the development of final state and regional plans. States would be free to identify other measures in their plans, if they are more cost-effective or better suited to individual state policies and resources. EPA's backstop authority under Section 111(d) would permit it to develop a federal implementation plan if a state fails to submit a satisfactory plan, but it could be based on only the first two recommendations, which directly control emissions from the regulated sources. Additional measures based on recommendations three and four would help states accommodate needs for increased flexibility, such as allowing the states to address units that have no cost-effective options for heat rate improvements due to site-specific factors, or where replacement of existing resources will require a longer compliance time frame due to the need for transmission mitigation or reinforcement, or other infrastructure additions.

# Appendix A

## Building Block 1 Related

**Issue Paper: Building Block #1**
**Heat Rate Improvements for Coal-Fired Power Plants**

## What is Efficiency and Heat Rate?

EPA's Clean Power Plan proposes to use a number of different "building blocks" to gauge the adequacy of state plans to reduce $CO_2$ emissions from the existing fossil-fueled fleet of electric generating units. This paper discusses the first "building block," improvements in the heat rate (or efficiency) of the existing coal-fired generating units.

The First Law of Thermodynamics, also known as the Conservation of Energy states that for any system, the energy out is equal to the energy put in. The energy that is produced can come in various forms (heat, sound, light, etc.). What is most important is the amount of "useful energy" produced from the process to meet a given objective. The amount of useful energy output from a given energy input determines a system's efficiency. Take, for example an automobile engine. The First Law states that 100% of the energy from the gasoline will be released in the engine when the fuel is burned. However, only about 20% of the energy produced in the vehicle's engine is useful in meeting the objective (moving the car from point A to point B). If so, then that engine is 20% efficient. The remaining 80% is lost through heat loss and friction in other parts of the engine and drivetrain system (e.g. pistons, valves, transmission, lubrication systems, fans, belts, etc.). There is no piece of equipment or system that is 100% efficient.

In the case of a fossil fuel-fired power plant, energy enters the plant in the form of fuel (e.g. coal, natural gas, etc.). The fuel is burned to release energy in the form of heat, which is then converted to mechanical energy by various means to turn a generator to produce electricity. In a coal-fired steam generating power plant, the energy from burning coal is used to heat water to steam. That steam then powers a turbine, which turns a generator to produce electricity. As with the car example above, not all of the energy produced by the combustion of coal is used to actually produce electricity. Much of that energy is lost in the form of waste heat, friction, sound, and other means by various parts of the process. All of these losses impact the overall efficiency of the plant. Technological innovations along with the ability to more closely monitor and reliably control processes have effectively improved the efficiency of fossil fuel fired power plants.

A measure of efficiency in a power plant is heat rate, which is how much fuel energy is used to make electricity. Lower heat rate values mean that the same amount of electricity is produced with less fuel, which means the system is more efficient. Power plant operators are motivated to optimize and lower heat rate (improve efficiency) because it lowers the cost of producing electricity. Technically, heat rate is the energy required (expressed in British Thermal Units or Btu) to generate 1 kilowatt of electricity, for 1 hour (also known as a kilowatt-hour or kWh). Assuming zero energy losses, it would take 3,412 Btu to produce 1 kWh. A theoretical power plant that is 100% efficient would then have a heat rate of 3,412 Btu/kWh. As discussed in more detail below, the efficiency of most existing fossil power plants is in the 30 to 40% range.

**How is Heat Rate Measured?**

Heat rate is periodically calculated for coal-fired power plants based on measurements of coal consumption, laboratory analyses of coal samples to determine an average Btu content in the coal consumed, and the total kilowatt-hours generated during the time period. The calculation follows below:

$$\text{Heat Rate (Btu / kwh)} = \frac{\text{lbs coal consumed x heat content of coal (Btu/lb)}}{\text{total kilowatt-hours generated}}$$

Existing monitoring techniques do not provide accurate instantaneous or continuous measurements of heat rate. In particular, the variability of fuel energy content and thermal fluctuations like ramping up/down on load can produce significant swings in instantaneous heat rate. In addition, the current methods used to estimate and report fuel heat input to EPA are not sufficiently precise to consistently detect a heat rate improvement rate of 6% or less.

Power plant heat rates can be expressed as a gross value or a net value. Gross unit heat rate is represented by the total energy input from the fuel divided by the gross kilowatt-hours generated by the generator. Net heat rate subtracts out the generated electricity that is used by the plant to run the fuel handling equipment, water treatment systems, emissions control systems, lighting and various other systems and components (collectively termed auxiliary load) that make up the complete power plant. Auxiliary load for a coal-fired plant is typically on the order of 5-10% of the total generator output. Typical practice in the industry is to report net unit heat rate, so as heat rate is discussed in the remainder of the paper, it is assumed to mean net heat rate. Below is a table from the U.S. Energy Information Administration that shows the 2012 average net unit heat rates for various power generating technologies using various fuels. The actual range of heat rate values within each category varies significantly due to a number of unit-specific design, fuel, and operational differences that are discussed in the sections that follow below.

| | 2012 Average Heat Rate (Btu/kWh) | | | |
|---|---|---|---|---|
| **Technology/Fuel** | **Coal** | **Petroleum** | **Natural Gas** | **Nuclear** |
| **Steam Generator** | 10,107 | 10,359 | 10,385 | 10,479 |
| **Gas Turbine** | -- | 13,622 | 11,499 | -- |
| **Internal Combustion** | -- | 10,416 | 9,991 | -- |
| **Combined Cycle** | -- | 10,195 | 7,615 | -- |

Heat Rate Source: U.S. Energy Information Administration,

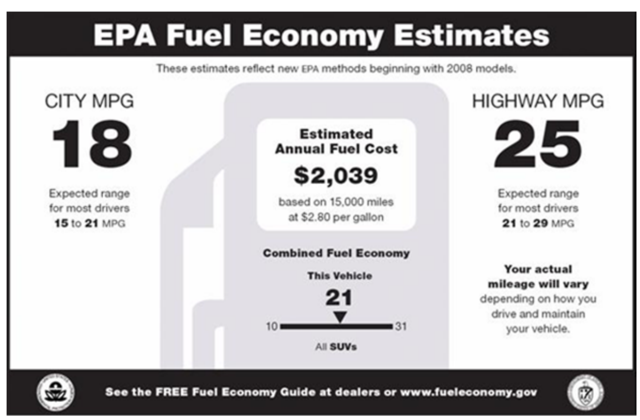
These average heat rate values above can be expressed as efficiencies in the following manner:
(3,412 Btu/kWh / Average Net Unit Heat Rate)  x 100 =  % Efficiency

| | 2012 Average Unit Cycle Efficiency (%) | | | |
|---|---|---|---|---|
| Technology/Fuel | Coal | Petroleum | Natural Gas | Nuclear |
| Steam Generator | 34% | 33% | 33% | 33% |
| Gas Turbine | -- | 25% | 30% | -- |
| Internal Combustion | -- | 33% | 34% | -- |
| Combined Cycle | -- | 33% | 45% | -- |

Existing U.S. coal-fired power plants had an average net unit heat rate of 10,107 Btu/kWh and were approximately 34% efficient in 2012.  Note that **higher efficiency translates to a lower heat rate.** This makes sense when considering that higher efficiency means that it takes less fuel to generate the same kilowatt-hour output.  Less fuel means fewer Btu, so in turn, a lower heat rate.  Reducing the heat rate of the existing coal fleet by 6% (per Building Block #1 of USEPA's proposed 111(d) rule) would lower the average net unit heat rate of every unit by roughly 600 Btu/kWh, and increase the average cycle efficiency of every unit by roughly 2%.

**Is a Unit's Heat Rate Constant, and If Not, What Impacts Heat Rate?**

It is extremely important to point out that the heat rate of a unit is **NOT** a constant value and varies significantly due to numerous factors which can have both positive and negative effects. Everything from basic unit design, fuel characteristics, operating load conditions, age/condition of equipment, maintenance and cleanliness of components, can all impact the heat rate.  A good analogy is that of automobile fuel efficiency.  Fuel efficiency of an automobile (typically expressed in miles per gallon or MPG) is most notably impacted by "city" versus "highway" driving.  The frequent stops, starts and speed changes associated with city driving result in worse gas mileage than when driving on a highway at a constant rate of speed with fewer changing conditions.



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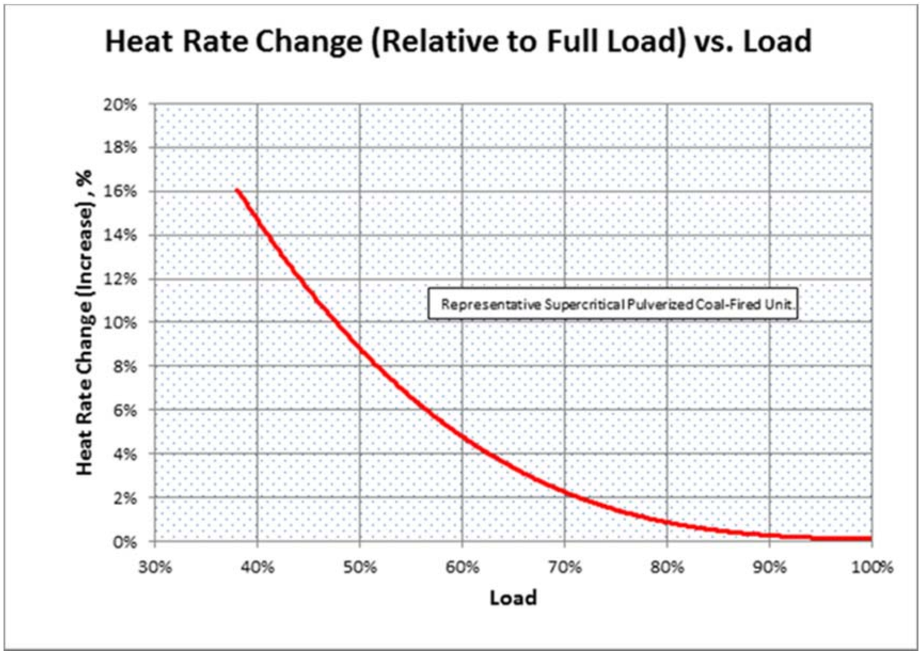
A fossil fuel fired power plant's heat rate is no different.  Operating in a full-load steady-state condition versus cycling loads up and down, or running at minimum loads for which the unit was not optimally designed have a negative impact on heat rate, reducing the kilowatt-hours out for every Btu that goes in.  The relationship of unit load to heat rate is shown for a typical unit in the graph below.




City and highway driving is not the only variable that impacts an automobile's fuel efficiency. Things like the basic aerodynamic design of the car, the condition of the road (smooth or rough), the air pressure in the tires, the cleanliness of the engine's air and fuel filtration systems, the fuel type and even the outside air temperature and humidity can all impact the fuel efficiency of an automobile. A power plant's heat rate can be similarly impacted by process and equipment design, maintenance and cleanliness of critical components, changes in weather conditions, changes in fuel energy content or fuel delivery, changes in process water and cooling water temperatures, etc.

The balance of this paper focuses on coal-fired power plants and discusses how achieving and sustaining heat improvement is extremely challenging – not just to accomplish, but also to measure.

**Is Every Coal Fired Steam Generating Unit Designed with the Same Heat Rate?**

The answer to this question is **absolutely not**. The diversity of the existing coal-fired generating fleet is not unlike the diversity of automobiles on the highway. The existing coal fleet is comprised of units of various ages, which were designed by different manufacturers to burn different types of coal. For example, the John W. Turk, Jr. Plant in Arkansas began operation in 2012. Turk utilizes a state-of-the-art ultra-supercritical steam cycle that allows for a greater transfer of heat energy from the combustion of coal to the steam circulating through the system. This design produces higher temperature and pressure steam than is typical in most units, which results in a higher overall efficiency for the Turk Plant (on the order of 38%) over conventional coal-fired steam generators. Turk's average net unit heat rate as a result of its state-of-the-art design is approximately 9,000 Btu/kWh. It has only been in the last decade, with advances in steam piping materials that designs like the Turk Plant have become feasible to build and operate. Currently, Turk is unique as it is the only operating ultra-supercritical unit in the U.S.

It is important to differentiate between a unit's average heat rate and its "design heat rate." Design heat rate is a theoretical target that represents an optimal, full-load, steady-state condition and is considered the best a unit could potentially achieve under its original design conditions. Units may achieve their design heat rate when new with all components in their best condition, but it is well-understood that the unit will not, and should not be expected to achieve its design unit heat rate under all operating conditions or throughout the life of the unit. The age of the unit, historic operations and maintenance over its life, as well as the retrofit of any auxiliary equipment like emissions controls will all negatively impact the heat rate over the life of the unit resulting in an average unit heat rate that is higher than the unit's original design heat rate. While there are similarities between units, and often even identically designed units at the same plant site, the heat rates of each unit are as unique as fingerprints, because each unit has been operated and maintained differently.

**What Can Be Done to Improve Heat Rate?**

Improving the heat rate of a unit usually means targeting one or more of the systems or components that make up the power plant for a specific improvement. The 2009 Sargent & Lundy (S&L) study on heat rate improvements, which EPA referenced in Building Block #1 of its proposed Clean Power Plan evaluated a series of potential heat rate improvements opportunities, and estimated potential ranges of heat rate reduction. S&L then applied their findings to two case studies to estimate potential improvements. The approach S&L used to determine potential heat rate improvements in the study was reasonable and practical. However, S&L's study was not intended to address the many variables that impact the measurability, feasibility and sustainability of the improvement opportunities which were identified. Since the study does not contain any evidence that the recommendations from the case studies were actually implemented and heat rate improvements measured, there is no empirical data demonstrating that the estimated improvements were actually achieved or could be maintained.

EPA inappropriately used the study to assume that the types of improvements estimated by S&L are equally applicable and achievable at each and every coal-fired power plant in the country. This is simply **not** the case. Below is a summary of the heat rate improvement strategies identified in the S&L report as they apply to AEP.

| HR Improvement Strategy | Sargent & Lundy Description | Applicability to AEP Units |
|---|---|---|
| Boiler Island – Materials Handling (fuel and ash) | Variable frequency drives provide no substantial reduction in plant heat rate.Pulverizer upgrades warranted only if facility is switching fuels. Ash handling is not considered a prime area of investment for plant heat rate reduction. | Variable frequency drives provide very limited benefit to systems which are NOT frequently cycled but operated at a steady output. Targeting such systems can provide small incremental benefit, but likely minimal measurable improvement to overall heat rate. |
| Boiler Overhaul | Major changes to a furnace are not undertaken due to regulations currently in place (NSR enforcement). Economizer replacements do occur during some SCR retrofit projects. | Addressed with proper maintenance. Heat transfer sections within the boiler (economizer, superheaters, reheaters), when needed are usually replaced in-kind (no heat rate improvement). May offer some restorative impact on heat rate, but no significant improvement. |
| Neural Network | Used to optimize plant performance during load changes. | Neural Networks "tested" on several units. No substantial benefit could be derived. Biggest heat rate benefit derived by minimizing excess air levels (set by limits). NN provided no benefit beyond unit operators' abilities and available tools to monitor and control excess air. AEP has a Generation Fleet Monitoring and Diagnostics team with intelligent software that identifies/flags pattern changes in operation and communicates performance analytics and best-practices back to the fleet. |
| Intelligent Sootblowers | Applicable to units burning PRB and lignite fuels - engages DCS with system controls for the sootblowers. | Only high-slagging units will see heat rate improvements. AEP has considered intelligent sootblowers and several units employ advanced water cannons for online boiler cleaning and slag removal. This option is site and fuel specific (high-slagging fuels) and not feasible for all units. |
| Air Heaters | Replace seals to reduce leakage and examine during emissions controls retrofits. Control acid dew point, particularly in connection with SCR retrofits. | Flue gas $O_2$ monitoring in place at many facilities to identify seal and air in-leakage issues. Addressed as part of ongoing maintenance. |
| Turbine Overhaul | Degradation and improved designs can be addressed, but greatest reductions are associated with changes in design, and performance will degrade over time. | Generally seals wear uniformly over time and heat rate improvement degrades. Turbine overhauls are routinely evaluated for each unit on a techno-economic basis and conducted on a schedule. AEP has performed turbine upgrades on 86% of the fleet that will be operating beyond 2016. |
| Feedwater Heaters | Cost of increasing heat transfer surfaces is prohibitive due to small incremental reductions in heat rate. | No feasible measures identified. |

| HR Improvement Strategy | Sargent & Lundy Description | Applicability to AEP Units |
|---|---|---|
| Condensers | Regular cleaning schedule has varying impacts on heat rate depending on location and cooling water characteristics. | Back pressures routinely monitored and diligent maintenance programs already in place across the fleet to address issues as soon as reasonably possible. Condenser tubes cleaned as necessary. |
| Boiler Feed Pumps | Ordinary wear and tear degrades performance and is addressed during overhauls or upgrades. | BFP rotors are swapped out on routine schedules to maintain high feedpump efficiency. Turbine drives on many AEP feed pumps already incorporate VFD efficiency. |
| Fans and VFDs | Installation of upgrades usually made in connection with emissions controls. | Many units have installed high-efficiency axial vane ID fans as part of emissions control projects to offset a portion of the heat rate penalty of adding emissions control equipment. |
| Emission Control Technologies | Discussion of potential improvements associated improved control system designs and power management features. | Limited power management savings benefit available for vast majority of units. Often state implemented Compliance Assurance Monitoring (CAM) Plans prohibit the use of power management features. |
| Boiler Water Treatment | Most power plants already have advanced water treatment systems installed. | AEP maintains very tight control over boiler water chemistry standards. Well defined corporate oversight program in place to insure high performance and high reliability. |
| Cooling Water Treatment | Proper maintenance of water quality in the cooling system maintains efficiency that could be lost through fouling. | Proper maintenance procedures are in place for cooling water treatment. Cells taken out service during part load and cool periods (auxiliary power management). |
| Advanced Cooling Tower Packing | Optimization of cooling water temperatures and fan requirements must be conducted to investigate effectiveness of upgrading fill or implementing VFDs for older fans. | High efficiency fills have proven to be problematic and susceptible to fouling thereby increasing heat rate. High efficiency fills have actually been replaced on many cooling tower units and heat rate improved. Fans (cells) taken out of service to reduce auxiliary loads during part load and cool periods. |
| Other Improvements | Motor replacement programs can yield minor heat rate improvements. | Similar to the assessment of VFDs, motor replacements are assessed on a system by system basis to determine feasibility and benefits. |

In addition, there are several distinct caveats to the report's findings must be considered that are imperative for understanding the realistic applicability and opportunity that any potential heat rate improvement project might afford. These include:

- improvements are not uniform and what may work for one unit, may not for another;
- the heat rate benefit of multiple improvement projects is not necessarily cumulative meaning that improvements in one area can be masked by operations or conditions in another thus diminishing any significant overall heat rate improvement;
- outside influences beyond the control of the unit operators and outside the optimized equipment design performance can alter or erase heat rate improvements as these plants are dispatched based upon electricity demand, which is driven by external forces (e.g. customers, regional transmission operators, etc.);
- improvements must be cost effective and measurable to justify their implementation;
- space constraints may exist on a particular unit that prohibit the addition of equipment or re-routing of ductwork/piping to implement a heat rate improvement project;
- the benefit derived from many of the suggested heat rate improvement technologies is finite, and will diminish over time due to the age and operation of the unit;
- for some heat rate improvement projects the potential benefits will only be apparent at full load operations, but offer no measurable improvements for cyclic or minimum load operations;
- conversely, some base load units would show no benefit to heat rate if the improvement was obtained only at lower loading of the unit;
- EPA's 111(d) proposal suggests that future coal power plants will be dispatched and operated much differently than in the past, which means that the feasibility and benefits of any potential heat rate improvement must be evaluated more in context with future operations that may not afford the same magnitude of improvement potential.

It is evident that potential heat rate improvements are impacted by many variables that are both within and beyond the control of unit owners and operators. An analogy to simplify this point is the decision to replace the air filter in your car, which is known to improve fuel efficiency, typically at higher vehicle speeds. However, if the highway by which you commute to work is suddenly closed and you are rerouted through busy city streets, any fuel efficiency improvement from new air filter might go unseen. Similarly, if improvements are made to components or systems within the power plant, and then the unit adds emissions controls to meet a new regulation or is cycled more frequently to balance intermittent loads from new wind and solar generation, the heat rate improvements may never be fully realized. In fact, depending upon the situation, the unit's average heat rate might actually deteriorate.

**Heat Rate Improvement Opportunities Are Limited for New and Well-Maintained Plants**

It should not be misinterpreted that heat rate improvements are not valuable or can never be implemented. Most power plant owners and operators have historically made heat rate improvements and overall efficiency of their generating units a high priority because of its positive impacts on operating costs and equipment performance. Remember, better heat rate means less fuel, which lowers the cost of generating electricity and creates an economic driver to improve efficiency. Many of the units in the existing coal generating fleet have proactively pursued and actively performed projects to improve heat rate, all while utilizing preventative maintenance and routine cleaning practices that promote and sustain efficient operations. Yet, no credit for proactive efforts like these is available in the EPA's Clean Power Plan and the amount of heat rate improvement contemplated by EPA is very aggressive and overly ambitious for units that have historically been well maintained and operated. For recently constructed coal units that were built with more advanced and more efficient technologies, many of the potential heat rate improvement opportunities listed above have already been incorporated into their designs. Any potential improvement opportunity will be minimal and certainly far from the level that EPA has considered in the proposed Clean Power Plan.

**Heat Rate Improvement Projects**
**Targeted During NSR Enforcement Initiative**

This list of over 400 efficiency improvement projects was compiled from Notices of Violation (NOVs) issued by the U.S. Environmental Protection Agency (EPA), and complaints filed by the Department of Justice or environmental advocacy groups alleging violations of the New Source Review (NSR) permitting program for failing to obtain a permit prior to undertaking equipment replacement or other heat rate improvement projects at electric utility generating units (EGUs). Those NOVs and complaints identify another 600 equipment replacement or repair projects that involve other components not specifically identified in the Sargent & Lundy report or EPA's GHG Abatement Measures Technical Support Document. These allegations are not an indication that a violation actually occurred. They are an indication of the chilling effect EPA's enforcement initiative will have on the willingness of EGU operators to pursue these or other heat rate improvement opportunities identified in EPA's GHG Abatement Measures Technical Support Document in the absence of clarification from EPA that these activities will not trigger NSR permitting requirements.

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| Soot blower | • *Environmental Defense, et al. v. Alcoa Inc.*, No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶¶ 46, 47 ("changing sootblower system controls" at Sandow Units 1 and 2 from 1984 to 1986), ¶ 48 ("replacement and addition of sootblowers" at Sandow Unit 3 from 1984 to 1986)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 73 ("replaced the sootblower drives and controls" on Alma Units 4 and 5 in 1998 to 1999), ¶ 79 ("upgraded the sootblowers" on Alma Units 1-3 in 2002), ¶ 81 ("upgraded the sootblowers" on Madgett Unit in 1998)<br><br>• NOV issued by EPA Region 5 to Indianapolis Power and Light Company on Sept. 29, 2009, Appendix C ("replacement of… soot blowers" on Petersburg Unit 2 in 1986)<br><br>• NOV issued to Portland General Electric Company, Sept. 28, 2010, ¶ 21 ("addition of soot blowing equipment" at Portland facility in 1998)<br><br>• *Conservation Law Foundation, Inc. v. Public Service Co. of New Hampshire*, No. 11-353, First Amend. Compl. (D.N.H. Dec. 4, 2013), ¶ 62 ("installing… sootblowers" at Merrimack 2 in 2008)<br><br>• NOI from Sierra Club to Wisconsin Power and Light Company *et al.*, dated Oct. 10, 2009, at 5 (soot blowers on Nelson Dewey Units 1 and 2 in 1999) |

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| Boiler Feed Pump | • *United States v. City of Akron, Ohio & Akron Energy Systems LLC*, No. 14-884, Compl. (N.D. Ohio Apr. 24, 2014), ¶ 110 ("replacing, rebuilding, and/or repairing… the boiler feedwater pump" at Akron Unit 32 in 1995 to 1996)<br><br>• NOV issued by EPA Region 7 to Nebraska Public Power District on Dec. 8, 2008, ¶ 1 (boiler feed pump replacements at Gerald Gentleman Unit 1 in 1991)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 199 ("added new boiler feed pumps" at Huntley Unit 63 in 1982 to 1983)<br><br>• *Conservation Law Foundation, Inc. v. Public Service Co. of New Hampshire*, No. 11-353, First Amend. Compl. (D.N.H. Dec. 4, 2013), ¶ 62 ("installing… main boiler feedpump control valve" at Merrimack 2 in 2008)<br><br>• *United States v. Southern Indiana Gas & Electric Co.*, No. 99-1692, Compl. (S.D. Ind. Nov. 3, 1999), ¶¶ 42, 49 ("overhauling the… boiler feed pump turbine and boiler feed pump" at Culley Unit 3 in 1997) |
| Economizer | • *United States, et al. v. Alabama Power Co.*, No. 01-152, Compl. (N.D. Ala. Jan. 12, 2001), ¶ 59 ("installation of new design spiral fin economizer" at Barry Unit 5 in 1993), ¶ 77 ("installation of new design spiral fin economizer" at Gorgas Unit 10 in 1994)<br><br>• *Environmental Defense, et al. v. Alcoa Inc.*, No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶ 47 ("changing the economizer" at Sandow Unit 2 in 1985)<br><br>• *United States v. AEP, et al.*, No. 99-1182, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 59 ("redesign and replacement… of an upgraded economizer" at Muskingum Unit 5 in 1985), ¶ 64 ("installation of a redesigned economizer" at Mitchell Units 1 and 2 in 1987 to 1988), ¶ 69 ("replacement of a redesigned economizer" at Cardinal Units 1 and 2 in 1989); Second Amend. Compl. (S.D. Ohio Sept. 16, 2004), ¶ 155 ("replacement of the economizer bank" at Conesville Unit 3 in 1988), ¶ 185 ("replacing the economizer" at John E. Amos Unit 1 in 1989)<br><br>• Second Amend. NOV issued by EPA Region 7 to Ameren Missouri on May 27, 2011, ¶ 53 ("replaced economizer" on Labadie Units 1-4 from 2001 to 2003), ¶ 54 ("replaced economizer" on Meramec Unit 1 in 2004, "replaced economizer |

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| | sidewall" on Meramec Unit 2 in 2004, and "replaced economizer" on Meramec Unit 4 in 2005), ¶ 56 ("replaced economizer" on Sioux Unit 1 in 2001 and "replaced economizer" on Sioux Unit 2 in 2000)<br><br>• *United States v. Ameren Missouri*, No. 11-77, Third Amend. Compl. (E.D. Mo. Apr. 24, 2014), ¶ 66 ("replace the economizer" at Rush Island Unit 1 in 2007), ¶ 71 ("replace the economizer" at Rush Island Unit 2 in 2010)<br><br>• NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A ("replaced… economizer tubes" on Gorsuch Units 1-3 in 1981 to 1984)<br><br>• NOV issued by EPA Region 7 to Associated Electric Power Cooperative on June 15, 2011, ¶ 40 ("replaced and redesigned economizer" at Thomas Hill Unit 3 in 1997 to 1998)<br><br>• *United States v. Cinergy Corp*., No. 99-1693, Compl. (S.D. Ind. Nov. 3, 1999), ¶ 44 ("replacement of the upper section of the economizer" at Cayuga Units 1 and 2 in 1984 to 1985), ¶ 49 (replacement of the economizer at Beckjord Unit 1 in 1987 and Unit 5 in 1991), ¶ 55 ("replacing the economizers" at Cayuga Units 1 and 2 in 1984 to 1985); Third Amend. Compl. (S.D. Ind. June 29, 2006), ¶ 145 ("replacement of the… upper economizer boiler tube hangers and hanger rods" at Wabash Unit 5 in 1990)<br><br>• *Sierra Club v. City of Holland*, No. 08-1183, First Amend. Compl. (W.D. Mich. Mar. 10, 2009), ¶ 65 ("replacing… economizer tubes" at De Young Unit 5 in 1988 to 2007)<br><br>• NOV issued by EPA Region 5 to Consumers Energy on Oct. 21, 2008, ¶ 37 ("designed, procured, fabricated, installed, and tested an improved replacement of entire economizer" on Campbell Unit 2 in 1986, "replaced existing 154-element fin-tubed economizer" on Weadock Unit 8 in 1989)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 80 ("replaced the economizer headers" on the Madgett Unit in 1996 to 1997)<br><br>• NOV issued by EPA Region 5 to Dayton Power and Light Company on Nov. 18, 2009, Appendix A (replacement of economizer at O.H. Hutchings Unit 6 in 2001)<br><br>• *Sierra Club v. Dayton Power & Light, et al*., No. 04-905, Compl. |

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| | (S.D. Ohio Sept. 21, 2004), ¶ 56 ("replacement of the economizer" at J.M. Stuart Unit 1 in 1997), ¶ 58 ("replacement of the economizer" at J.M. Stuart Unit 3 post-1975); First Amend. Compl. (S.D. Ohio Oct. 13, 2006), ¶ 46 (replacement of economizer surface at J.M. Stuart Unit 1 in 1986)<br><br>• *United States v. DTE Energy Co., et al*., No. 10-13101, Amended Compl. (E.D. Mich. Apr. 9, 2014), ¶ 70 ("replacement of the economizer" at Monroe Unit 2 in 2010), ¶ 105 ("replacement of the economizer" at Trenton Unit 9 in 2007)<br><br>• *United States v. Duke Energy Corp.*, No. 00-1262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 41 ("replacement of the economizer" at Allen Unit 5 in 1996), ¶ 51 ("replacement of both banks of the economizer" at Allen Unit 4 in 1996), ¶ 87 ("replacement and redesign of both banks of the economizer" at Belews Unit 2 in 1999), ¶ 105 ("redesigning and replacing both banks of economizers" at Belews Unit 1 in 2000), ¶ 159 ("replacement of the lower economizer" at Marshall Unit 2 in 1989), ¶ 195 ("replacement of the upper economizer banks" at Cliffside Unit 4 in 1990), ¶ 204 ("redesign and replacement of the Unit No. 5 economizer" at Cliffside in 1992 and 1995), ¶ 213 ("replacement of economizer banks" at Cliffside Unit 1 in 1993), ¶ 240 ("replacement… of the economizer" at W.S. Lee Unit 3 in 1990), ¶ 249 ("replacement or refurbishment of the… economizer" at Riverbend Unit 4 in 1990), ¶ 258 ("replacement or redesign of the economizer" at Riverbend Unit 6 in 1991), ¶ 267 ("replacement or redesign of the economizer" at Riverbend Unit 7 in 1992), ¶ 285 ("replacement of the lower economizer bank" at Marshall Unit 1 in 1992)<br><br>• *United States v. Georgia Power Co., et al*., No. 99-2859, Amend. Compl. (N.D. Ga. May 11, 2001), ¶ 71 ("installation of a new economizer" at Bowen Unit 2 in 1992)<br><br>• *United States v. Illinois Power Co.*, No. 99-833, Compl. (S.D. Ill. Nov. 3, 1999), ¶ 42 ("complete change-out of the economizer" for Baldwin Unit 3 in 1982)<br><br>• NOV issued by EPA Region 5 to Indianapolis Power and Light Company on Sept. 29, 2009, Appendix A ("replacement of the economizer" at Harding Street Unit 7 in 1994), Appendix B (replacement of the economizer at Eagle Valley Unit 4 in 2002 and Unit 6 in 1991), Appendix C ("replacement of the economizer" at Petersburg Generating Station Unit 2 in 1986 and |

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| | Unit 4 in 2001)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 101 (modifications at Fisk Unit 19 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 201 (modifications at Waukegan Unit 7 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 219 (modifications at Waukegan Unit 8 in 1996 "described in the NOV issued to Defendant on July 31, 2007"); see NOV issued by EPA Region 5 to Midwest Generation LLC and Commonwealth Edison on July 31, 2007, ¶ 35 ("installed economizer headers" on Fisk Unit 19 in 1992 and "replaced economizer header" on Fisk Unit 19 in 1996), ¶ 47 ("replaced economizer headers" on Waukegan Unit 7 in 1996 and "replaced economizer headers" on Waukegan Unit 8 in 1996)<br><br>• *United States v. EME Homer City Generation, L.P., et al.*, No. 11-19, Compl. (W.D. Pa. Jan. 6, 2011), ¶ 68 ("replace the economizer" at Homer City Unit 1 in 1994), ¶ 79 ("replace the economizer" at Homer City Unit 2 in 1991)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 72 ("replaced… economizer tubes" at Dunkirk Unit 1 in 1985), ¶ 102 ("replaced sections of the economizer" at Dunkirk Unit 2 in 1983), ¶ 234 ("replaced the economizer" at Huntley Unit 64 in 1989)<br><br>• *United States v. Oklahoma Gas & Electric Co.*, No. 13-690, Compl. (W.D. Okla. July 8, 2013), ¶ 42(a) ("complete replacement and reconfiguration of the economizer" at Muskogee Unit 4 in 2003); ¶ 42(b) ("replacement of the economizer" at Sooner Unit 2 in 2004); ¶ 42(f) ("replacement of the economizer" at Muskogee Unit 5 in 2005); ¶ 42(g) ("replacement of the economizer" at Sooner Unit 1 in 2006)<br><br>• *Sierra Club v. Oklahoma Gas & Electric Co.*, No. 13-356, Compl. (E.D. Okla. Aug. 12, 2013), ¶ 31 ("replacing the economizer and the economizer tube support system" at Muskogee Unit 6 in 2008)<br><br>• *United States v. Ohio Edison Co., et al.*, No. 99-1181, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 42 (replacing the economizer at Sammis Unit 5 in 1990, at Sammis Unit 6 in 1987, and at Sammis Unit 7 in 1989)<br><br>• NOV issued to City of Painesville, Painesville Municipal Electric Plant on Aug. 18, 2009, Appendix A (replaced economizer at Unit |

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| | 4 in 1985)<br><br>• NOV issued to Portland General Electric Company on Sept. 28, 2010, ¶ 21 ("addition of tubing to the economizer" at Portland facility in 1998)<br><br>• *Sierra Club, et al. v. PPL Montana LLC, et al.*, No. 13-32, Compl. (D. Mont. Mar. 6, 2013), ¶ 62 ("replacing the economizer" at Colstrip Unit 1 in 2012), ¶ 70 ("replacing the economizer" at Colstrip Unit 2 in 1992)<br><br>• *New Jersey v. Reliant Energy*, No. 07-5298, Compl. (E.D. Pa. Dec. 18, 2007), ¶ 78 ("replacing 54 tubes in the radiant economizer" at Portland Unit 1 in 1986)<br><br>• NOV issued by EPA Region 5 to Richmond Power and Light on March 26, 2009, ¶ 38 ("re-tubing of economizer section of the boiler" at Whitewater Valley Unit 2 in 1996)<br><br>• *United States v. Southern Indiana Gas & Electric Co.*, No. 99-1692, Compl. (S.D. Ind. Nov. 3, 1999), ¶ 42 ("replacement of the Unit 3 economizer bank in 1994" and the "installation of a new economizer for Unit 1 in 1991" at Culley Station)<br><br>• *National Parks Conservation Ass'n, Inc., et al. v. Tennessee Valley Authority*, No. 01-071, Compl. (E.D. Tenn. Feb. 13, 2001), ¶ 43 ("replacement of all economizer elements in the "A" and "B" furnace" at Bull Run facility in 1988)<br><br>• *United States v. Virginia Electric & Power Co.*, No. 03-517-A, Compl. (E.D. Va. Apr. 21, 2003), ¶ 43 ("replacing the Unit 6 economizer tubes in 1995" at Chesterfield facility), ¶ 49 ("replacing the economizer at Unit 1 in 1988, replacing the economizer at Unit 2 in 1989, and replacing the economizer at Unit 3 in 1992" at Mount Storm facility)<br><br>• *United States v. Westar Energy, Inc.*, No. 09-2059, Compl. (D. Kan. Feb. 4, 2009), ¶ 39 ("replacing the economizer on Jeffrey unit 1 in 1999" and "replacing the economizer on Jeffrey unit 2 in 1999")<br><br>• *United States v. Wisconsin Electric*, No. 03-371, Compl. (E.D. Wis. Apr. 29, 2003), ¶ 41 ("replacement of economizers" at Oak Creek facility, date not specified) |

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| | • *United States v. Wisconsin Power & Light Co., et al.*, No. 13-266, Compl. (W.D. Wis. Apr. 22, 2013), ¶ 52 ("replacement of the economizer" at Columbia Unit 1 in 2006)<br><br>• NOV issued to Wisconsin Public Service Corporation Nov. 19, 2009, ¶ 32 (economizer replacement at Weston Unit 1 in 1990-1991)<br><br>• *United States v. Wisconsin Public Service Corp.*, No. 13-10, Compl. (E.D. Wis. Jan. 4, 2013), ¶ 38 ("replacement of the economizer" at Weston Unit 2 in 1993)<br><br>• NOI from State of New York, *et al.* to Allegheny Energy, Inc. dated May 20, 2004, at 3 (replaced economizer at Albright Unit 3 in 1989) |
| Turbine Work | • NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A ("[o]verhaul and uprate work on Turbine Nos. 1, 2, 3, and 4" at Gorsuch facility in 1989 to 1991)<br><br>• *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, Compl. (S.D. Ohio Sept. 21, 2004), ¶¶ 56, 82 ("activities related to the overhaul of the turbine" at J.M. Stuart Unit 1 in 1980), ¶¶ 57, 83 ("activities related to the overhaul of the turbine" at J.M. Stuart Unit 2 post-1975)<br><br>• *United States v. Duke Energy Corp.*, No. 00-1262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 32 ("major… turbine overhaul" at Allen Unit 5 in 2000), ¶ 60 ("major… turbine overhaul" at Allen Unit 4 in 1998)<br><br>• *United States v. East Kentucky Power Cooperative, Inc.*, No. 04-34, Compl. (E.D. Ky. Jan. 28, 2004), ¶¶ 60, 65 ("replacement or renovation of major components of the… turbine" at Dale Unit 4 in 1994 to 1995), ¶¶ 76, 81 ("replacements or renovations of major components of the… turbine" at Dale Unit 3 in 1996)<br><br>• *United States v. Kentucky Utilities Co.*, No. 07-75, Compl. (E.D. Ky. Mar. 12, 2007), ¶¶ 50, 58 ("various replacements or renovations of major components of the… turbine" thereby "replacing the turbine with a new higher capacity turbine" at E.W. Brown Unit 3 in 1997)<br><br>• *United States v. Southern Indiana Gas & Electric Co.*, No. 99-1692, Compl. (S.D. Ind. Nov. 3, 1999), ¶¶ 42, 49 ("overhauling |

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| | the… turbine” at Culley Unit 3 in 1997)<br><br>• *United States, et al. v. AEP, et al.*, No. 99-1182, Second Amend. Intervenor Compl. (S.D. Ohio Sept. 20, 2002), ¶ 578 (“rebuilt the turbine including replacement of turbine and rotor blades” at Gavin Unit 1 in 1990 to 1996)<br><br>• *United States v. AEP, et al.* (AEP II), No. 05-360, Compl. (S.D. Ohio Apr. 8, 2005), ¶ 97 (“replacement of the low pressure turbine rotor and stationary steam path components” at Conesville Units 5 and 6 in 1997)<br><br>• *United States v. Duke Energy Corp.*, No. 00-1262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 195 (“turbine rehabilitation” at Cliffside Unit 4 in 1990)<br><br>• NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A (“[r]eplace low pressure turbine rotor on Turbine Nos. 2 and 4 [and r]eplace low pressure turbine rotor and diaphragms on Turbine No. 1” at Gorsuch facility in 1989 to 1991)<br><br>• *Dine Citizens, et al. v. Arizona Public Service Co., et al.*, No. 11-889, Compl. (D. N.M. Oct. 4, 2011), ¶ 57 (“replacement of the high pressure section of the main turbine, along with some or all of the turbine controls; replacement of the fourth-stage rows of blades in the low-pressure sections of the main turbine; replacement of one or more rows of blades in one of the low-pressure sections (section A) of the main turbine; replacement of one or more rows of blades of the intermediate-pressure section of the main turbine; and rewinding of the rotor (field) in the generator that is associated with the low pressure turbine” at Four Corners Unit 5 post-2007 ), ¶ 59 (“replacement of the high pressure section of the main turbine, along with turbine controls; replacement of the fourth-stage rows of blades in the low-pressure sections of the main turbine; replacement of the second stage rows of blades in one of the low-pressure sections (section B) of the main turbine; replacement of one or more rows of blades in the intermediate-pressure section of the main turbine; rewinding of the rotor (field) in the generator associated with the high-pressure turbine; re-wedging of the generator associated with the low-pressure turbine” at Four Corners Unit 4 post-2007)<br><br>• *United States v. Cinergy Corp.*, No. 99-1693, Compl. (S.D. Ind. Nov. 3, 1999), ¶ 49 (“replacement of the… turbine blades, and |

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| | other turbine equipment" at Beckjord Unit 4 in 1989)<br><br>• NOV issued by EPA Region 5 to Consumers Energy on Oct. 21, 2008, ¶ 37 ("[r]eplaced the Intermediate Pressure (IP) and Low Pressure (LP) turbine, L-0 (low pressure, level zero) blades (three rows, 2 x LP, 1 x IP) sections and diaphragms, replaced first stage IP turbine rotating blades (one row)" at Weadock Unit 8 in 1996)<br><br>• *United States v. DTE Energy Co., et al*., No. 10-13101, Amended Compl. (E.D. Mich. Apr. 9, 2014), ¶ 80 ("replacement/upgrade of the high and low pressure turbines" at Monroe Unit 2 in 2005), ¶ 85 ("replacement/upgrade of the high and low pressure turbines" at Monroe Unit 3 in 2004)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 137 (modifications at Juliet Unit 7 in 1994 "described in the NOV issued to Defendant on July 31, 2007"); see NOV issued by EPA Region 5 to Midwest Generation, LLC and Commonwealth Edison on July 31, 2007, ¶ 38 ("[r]eplaced turbine high pressure generator rotor" at Joliet Unit 7 in 1994), ¶ 47 ("turbine work" at Waukegan Unit 8 in 1993).<br><br>• *New York v. Niagara Mohawk Power Corp., et al*., No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 73 ("replaced… turbine buckets" at Dunkirk Unit 1 in 1991), ¶ 104 ("replaced buckets on the turbine [and] installed turbine water induction prevention equipment" at Dunkirk Unit 2 in 1990), ¶ 134 ("replaced the first stage buckets on the turbine" at Dunkirk Unit 3 in 1982), ¶ 136 ("replaced… turbine buckets" at Dunkirk Unit 3 in 1986), ¶ 202 ("upgraded the turbine" at Huntley Unit 63 in 1987), ¶ 233 ("installed turbine water induction prevention equipment" at Huntley Unit 64 in 1987), ¶ 323 ("replaced the turbine (HP-IP outer and inner shells, HP-IP rotor including all the buckets and diaphragms, combined thrust and two journal bearings, all three sections of steam packings, packing boxes and rings, oil deflectors, all control valves, and all instrumentation and electrical hardware)" at Huntley Unit 67 in 1991), ¶ 352 ("replaced… the high pressure turbine nozzle block" at Huntley Unit 68 in 1982), ¶ 357 ("rehabilitated the Unit 67 turbine and installed it in Unit 68" in 1993)<br><br>• *United States v. Oklahoma Gas & Electric Co.*, No. 13-690, Compl. (W.D. Okla. July 8, 2013), ¶ 42(c)-(e) ("replacement of turbine blades" at Muskogee Units 5 and 6 in 2004 and Unit 4 in 2005), ¶ 42(f) ("replacement of… low pressure blades as well as |

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| | various other upgrades to the steam turbine system… intended to 'greatly enhance the operability, efficiency, and maximum continuous net generation' of Muskogee Unit 5" in 2005), ¶ 42(g) ("replacement of the… turbine rotor, and low pressure blades" at Sooner Unit 1 in 2006), ¶ 42(h) ("replacement of turbine blades [and] the rotor" at Sooner Unit 2 in 2006)<br><br>• *United States v. Ohio Edison Co., et al*., No. 99-1181, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 42 ("replacing the… turbine rotors" at Sammis Unit 7 in 1989)<br><br>• *Sierra Club v. Portland General Electric Co.*, No. 08-1136, Compl. (D. Or. Sept. 30, 2008), ¶¶ 161, 232, 246 ("retrofit of both double-flow, low-pressure turbine rotors in 2000, and related projects… a plant turbine upgrade project… and related projects… steam turbine rotor… repairs in 2005 and 2006, and related projects[,] and… low-pressure turbine unit repairs in 2006, and related projects" at the Boardman facility)<br><br>• *Sierra Club, et al. v. PPL Montana LLC, et al*., No. 13-32, Compl. (D. Mont. Mar. 6, 2013), ¶ 95 ("replacing the Unit 4 low-pressure (LP) turbine, and possibly the Unit 4 intermediate pressure (IP) turbine" at Colstrip in 2009), ¶ 111 ("replacement of the high pressure (HP) turbine and the intermediate pressure (IP) turbine" at Colstrip Unit 2 in 2008), ¶ 126 ("replace the high pressure (HP) turbine" at Colstrip Unit 3 in 2007) , ¶ 142 ("replace the high pressure (HP) turbine" at Colstrip Unit 4 in 2006), ¶ 158 ("replace the high pressure (HP) and intermediate pressure (IP) turbines" at Colstrip Unit 1 in 2006), ¶ 219 ("replace the high pressure (HP) turbine with a turbine from another utility; equip the HP turbine with a unified lift capability; and replace sections of the low pressure (LP) turbine with a 'ruggedized' design" at Colstrip Unit 3 in 1995), ¶ 235 (replace the high pressure (HP) turbine with a turbine from another utility; equip the HP turbine with a unified lift capability; and replace sections of the low pressure (LP) turbine with a 'ruggedized' design" at Colstrip Unit 4 in 1996)<br><br>• *Environmental Defense, et al. v. Alcoa Inc*., No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶ 46 ("significantly overhauled Sandow Unit 1" between 1984 and 1986 including "changing the turbine high pressure rotor," "changing the high pressure turbine inner shell," and "changing the L-1 turbine buckets"), ¶ 47 ("significantly overhauled Sandow Unit 2" in 1985 including "changing various turbine buckets and diaphragms"), ¶ 48 ("significantly overhauled Sandow Unit 3" from 1984 to 1986 including "changing the L-1 turbine buckets" and "conversion of |

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| | the seals on the turbine from water to steam")<br><br>• *Conservation Law Foundation, Inc. v. Public Service Co. of New Hampshire*, No. 11-353, First Amend. Compl. (D.N.H. Dec. 4, 2013), ¶ 61 ("removed a high pressure/intermediate pressure ("HP/IP") turbine, and replaced it with a new HP/IP turbine" at Merrimack Unit 2 in 2008)<br><br>• *United States v. Oklahoma Gas & Electric Co.*, No. 13-690, Compl. (W.D. Okla. July 8, 2013), ¶ 42(f) ("replacement of… low pressure blades" at Muskogee Unit 5 in 2005) |
| Boiler Overhaul | • *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, Compl. (S.D. Ohio Sept. 21, 2004), ¶ 46 ("complete overhaul of the entire boiler unit during the spring of 1991" at J.M. Stuart Unit 4)<br><br>• *United States v. Dominion Energy*, No. 13-3086, Compl. (C.D. Ill. Apr. 1, 2013), ¶ 38 ("the complete overhaul of the boilers at Kincaid Units 1 and 2 in 1998 and 1999, including replacement of cyclones, coal burners, boiler walls, and furnace floors on both units")<br><br>• *United States v. Duke Energy Corp.*, No. 00-1262, Compl. (M.D.N.C. Dec. 22, 2000), ¶ 32 ("a major boiler… overhaul" at Allen Unit 5 in 2000), ¶ 60 ("a major boiler… overhaul" at Allen Unit 4 in 1998), ¶ 69 ("replacement and redesign of major components of the boilers" at Allen Unit 2 in 1988), ¶ 78 ("replacement and redesign of major components of the boilers" at Allen Unit 1 in 1989)<br><br>• *United States v. East Kentucky Power Cooperative, Inc.*, No. 04-34, Compl. (E.D. Ky. Jan. 28, 2004), ¶¶ 60, 65 ("replacement or renovation of major components of the boiler" at Dale Unit 4 in 1994 to 1995), ¶ 76 ("replacements or renovations of major components of the boiler" at Dale Unit 3 in 1996)<br><br>• *United States v. Kentucky Utilities Co.*, No. 07-75, Compl. (E.D. Ky. Mar. 12, 2007), ¶¶ 50, 58 ("replacements or renovations of major components of the boiler" at E.W. Brown Unit 3 in 1997)<br><br>• *National Parks Conservation Ass'n, Inc., et al. v. Tennessee Valley Authority*, No. 01-0403, Compl. (N.D. Al. Feb. 13, 2001), ¶ 70 ("significant overhaul of the boiler that involved the replacement and redesign of the waterwalls and horizontal reheater, the modification of the startup system, the modification of the superheater by adding wingwalls in the furnace, the replacement |

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| | of the gas proportioning dampers, the replacement of the windbox, the replacement and redesign of the control system, and the addition of a balanced draft conversion system” at Colbert Unit 5 in 1982) |
| Air Heaters | • *United States, et al. v. Alabama Power Co.*, No. 01-152, Compl. (N.D. Ala. Jan. 12, 2001), ¶ 77 (“installation of redesigned air heaters” in Gorgas Unit 10 in 1994)<br><br>• *United States v. AEP, et al.*, No. 99-1182, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 54 (“replacement… of the Unit 4 tubular air heater” at Tanners Creek in 1992)<br><br>• Second Amend. NOV issued by EPA Region 7 to Ameren Missouri on May 27, 2011, ¶ 54 (“replaced air heater” at Meramec Unit 1 in 2004)<br><br>• NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A (“rebuild of air heaters” on Gorsuch Units 1-3 in 1981 to 1984)<br><br>• *Dine Citizens, et al. v. Arizona Public Service Co., et al.*, No. 11-889, Compl. (D. N.M. Oct. 4, 2011), ¶¶ 56, 58 (“replacement of the baskets in the hot and cold ends of the air heaters associated with the boiler” at Units 4 and 5 post-2007)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 76 (“installed Air Heater Basket 4” at Alma facility in 2001), ¶ 84 (“replaced the heater basket” at the Madgett Unit in 2003)<br><br>• *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, First Amend. Compl. (S.D. Ohio Oct. 13, 2006), ¶ 46 (replacement of air heater baskets on J.M. Stuart Units 1-4 from 1980 to 1993 and “[i]mproving the primary air system” at J.M. Stuart Units 1-4 in 2001)<br><br>• *United States v. Dominion Energy*, No. 13-3086, Compl. (C.D. Ill. Apr. 1, 2013), ¶ 38 (“complete refurbishment of the air heater at Kincaid Unit 2 in 1994”)<br><br>• *United States v. DTE Energy Co., et al.*, No. 10-13101, Amended Compl. (E.D. Mich. Apr. 9, 2014), ¶ 85 (“replacement of the air heaters” at Monroe Unit 3 in 2004)<br><br>• *United States v. Illinois Power Co.*, No. 99-833, Compl. (S.D. Ill. |

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| | Nov. 3, 1999), ¶ 49 ("replaced portions of the cold air heater tubes" in Baldwin Unit 1 in 1990), ¶ 51 ("replaced portions of [Baldwin] Unit 2's cold end air heater tubes" in 1988)<br><br>• NOV issued by EPA Region 5 to Indianapolis Power and Light Company on Sept. 29, 2009, Appendix C ("replacement of the combustion air heaters" on Petersburg Unit 3 in 1993)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 119 (modifications at Joliet Unit 6 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 165 (modifications at Powerton Unit 5 in 1995 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 219 (modifications at Waukegan Unit 8 in 1996 "described in the NOV issued to Defendant on July 31, 2007"); see NOV issued by EPA Region 5 to Midwest Generation, LLC and Commonwealth Edison on July 31, 2007, ¶ 38 ("replaced air heater baskets" on Joliet Unit 6 in 1996), ¶ 44 (replaced baskets of regenerative air preheaters at Powerton Unit 5 in 1995 and at Unit 6 in 1996), ¶ 47 ("replaced air heater baskets" on Waukegan Unit 8 in 1996)<br><br>• NOV issued by EPA Region 3 to EME Homer City Generation, L.P., *et al.* on Nov. 1, 2010, at ¶ 64 ("replacement of primary air heater bypass duct" on Homer City Unit 2 in 1991)<br><br>• *New York v. Niagara Mohawk Power Corp., et al*., No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 73 ("modified the preheater" at Dunkirk Unit 1 in 1991), ¶ 106 ("upgraded the air preheater" at Dunkirk Unit 2 in 1997), ¶ 135 ("replaced elements in the air preheaters" at Dunkirk Unit 3 in 1985), ¶ 321 ("replaced… air heater baskets" on Huntley Unit 67 in 1982)<br><br>• NOV issued by EPA Region 5 to Northern Indiana Public Service Company on Sept. 29, 2004, ¶ 19 ("replacement of the air heater" on Bailly Unit 7 in 1986)<br><br>• NOV issued by EPA Region 5 to the City of Painesville, Painesville Municipal Electric Plant on Aug. 18, 2009, Appendix A ("retubed tubular air heater" at Unit 3 in 2005 and Unit 4 in 2006, and "partial replacement of air heater" on Unit 4 in 1992)<br><br>• *Conservation Law Foundation, Inc. v. Public Service Co. of New Hampshire*, No. 11-353, First Amend. Compl. (D.N.H. Dec. 4, 2013), ¶ 62 ("installing… air heater tube" at Merrimack 2 in 2008)<br><br>• NOI from State of New York to Allegheny Energy, Inc., dated |

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| | Sept. 15, 1999, at 2 (replaced the air heater basket at Fort Martin Units 1 and 2 in 1994 to 1997)<br><br>• NOV issued by EPA Region 7 to Ameren Missouri, May 27, 2011, ¶ 53 ("replaced air preheater rotor" at Labadie Units 1, 2, and 4 in 2001 to 2002, "replaced air preheater" at Labadie Unit 3 in 2003)<br><br>• *United States v. Ameren Missouri*, No. 11-77, Third Amend. Compl. (E.D. Mo. Apr. 24, 2014), ¶ 66 ("project to replace… air preheater" at Rush Island Unit 1 in 2007), ¶ 71 ("project to replace… air preheater" at Rush Island Unit 2 in 2010) |
| Feedwater Heater | • *United States v. AEP, et al.* (AEP II), No. 05-360, Compl. (S.D. Ohio Apr. 8, 2005), ¶ 112 ("replacing… high pressure feedwater heaters" for John E. Amos Unit 2 in 1990)<br><br>• NOV issued by EPA Region 7 to AmerenUE on Jan. 26, 2010, ¶ 54 ("replaced feed water heater" on Meramec Unit 3 in 2000 and on Meramec Unit 4 in 2001 to 2002)<br><br>• NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A (retubed "high pressure feedwater heaters" at Gorsuch Unit 4 in 1984)<br><br>• *Dine Citizens, et al. v. Arizona Public Service Co., et al.*, No. 11-889, Compl. (D. N.M. Oct. 4, 2011), ¶ 59 ("replacement of one or more of the high-pressure feedwater heaters" at Four Corners Unit 4 post-2007)<br><br>• *United States v. Cinergy Corp.*, No. 99-1693, Compl. (S.D. Ind. Nov. 3, 1999), ¶ 44 ("replacement of the… high pressure heater" at Cayuga Unit 1 in 1995); Third Amend. Compl. (S.D. Ind. June 29. 2006), ¶ 145 ("installation of stainless-steel-tubed feedwater heaters" in Wabash Unit 6 in 1987)<br><br>• NOV issued by EPA Region 5 to Consumers Energy on Oct. 21, 2008, ¶ 37 ("retubed 1-2 low-pressure feedwater heater" at Karn Unit 1 in 1998)<br><br>• *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, First Amend. Compl. (S.D. Ohio Oct. 13, 2006), ¶ 46 ("[r]eplacement of the Unit 1 No. 6 feedwater heater" at the J.M. Stuart facility in 1980, "[r]eplacement of the… 1A and 1B high pressure heaters" at J.M. Stuart Unit 3 in 1989, "[r]eplacement of the… 2A and 2B high pressure heaters" at J.M. Stuart Unit 1 in 1990, Unit 2 in 1992 and 1994, Unit 3 in 1991 and 2003, and Unit 4 in 2004, |

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| | “[r]eplacement of the… 3A and 3B high pressure heaters” at J.M. Stuart Unit 3 in 2003 and Unit 4 in 1993)<br><br>• NOV issued by EPA Region 5 to Midwest Generation, LLC and Commonwealth Edison on July 31, 2007, ¶ 35 (“[r]eplaced heat exchanger 7A high pressure feedwater heater” at Fisk Unit 19 in 1992)<br><br>• *United States v. Minnkota Power Cooperative, Inc., et al.*, No. 06-034, Compl. (D. N.D. Apr. 24, 2006), ¶ 38 (“modifications to the… feedwater heater” at Milton R. Young Unit 2 in 1988)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 325 (“replaced high pressure feedwater heaters” at Huntley Unit 67 in 1999), ¶ 352 (“replaced… feedwater heaters” at Huntley Unit 68 in 1982), ¶ 359 (“replaced the high pressure feed water heater” on Huntley Unit 68 in 1997)<br><br>• *United States v. Wisconsin Power & Light Co., et al.*, No. 13-266, Compl. (W.D. Wis. Apr. 22, 2013), ¶ 52 (“replacement of… feedwater heaters” at Columbia Unit 1 in 2006)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 72 (“replaced Feedwater Heater 4” at Alma facility in 1993 to 1994), ¶ 77 (“replaced the high pressure #5 feedwater heater” at Alma facility in 2001 to 2002), ¶ 78 (“replaced Feedwater Heater 5” at Alma facility in 2002 to 2003), ¶ 89 (“replaced the feedwater heater” on Genoa Unit 3 in 2000 to 2001), ¶ 91 (“replaced the heater #5” on Genoa Unit 3 in 2004)<br><br>• NOI from State of New York, *et al.* to Allegheny Energy, Inc. dated May 20, 2004, at 4 (replaced high pressure feedwater heaters at Pleasants Unit 1 in 1989 and Unit 2 in 1988) |
| Condenser | • *Environmental Defense, et al. v. Alcoa Inc.*, No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶ 48 (“changing significant sections of condenser tubes” at Sandow Unit 3 between 1984 and 1986)<br><br>• *United States v. AEP, et al.*, No. 99-1182, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 64 (“replacement of all tubes in the main condensers in Units 1 and 2” at Mitchell facility in 1989), ¶ 74 (“replacement of all tubes in the main condensers” in Unit 1, Unit 2, and Unit 4 in 1990 and 1991 at Philip Sporn facility); Amend. Compl. (S.D. Ohio Mar. 1, 2000) ¶ 263 (“retubing the main condenser” at Kanawha River Unit 1 in 1991); Second Amend. Compl. (S.D. |

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| | Ohio Sept. 16, 2004), ¶ 185 ("retubing the main condenser" for Units 1 and 3 at John E. Amos facility in 1989 and 1995, respectively), ¶ 215 ("retubing of the low pressure, high pressure, and auxiliary condensers for Unit 5" at Philip Sporn facility in 1992)<br><br>• *United States v. AEP, et al.* (AEP II), No. 05-360, Compl. (S.D. Ohio Apr. 8, 2005), ¶ 112 ("retubing the main condenser" at John E. Amos facility Unit 2 in 1990)<br><br>• NOV issued by EPA Region 7 to AmerenUE on Jan. 26, 2010, ¶ 53 (Labadie Unit 4 "underwent condenser retubing" in 2002), ¶ 54 (Meramec Unit 3 "underwent condenser retubing" in 2000 and Meramec Unit 4 "underwent condenser retubing" in 2001-2002), ¶ 55 (Rush Island Unit 1 "underwent condenser retubing" in 2001-2002)<br><br>• NOV issued to American Municipal Power-Ohio, Inc. by EPA Region 5 on March 27, 2009, Appendix A ("retube of condenser" on Units 1-4 at Gorsuch Generating Station from 1981 to 1991)<br><br>• *United States v. Cinergy Corp.*, No. 99-1693, Third Amend. Compl. (S.D. Ind. June 29. 2006), ¶ 172 ("replacement of the condenser tubing on Unit 5 in 1991" and "replacement of the condenser tubing on Unit 6 in 1995" at Beckjord facility); First Amend. Compl. of Plaintiff Intervenors (S.D. Ind. June 30, 2006), ¶ 133 ("retubing the Unit 2 condenser with titanium tubing in 1990" at Gallagher facility), ¶ 214 ("replacement of condenser tubes" on Unit 8 in 1999-2001 at Miami Fort facility)<br><br>• *Sierra Club v. City of Holland*, No. 08-1183, First Amend. Compl. (W.D. Mich. Mar. 10, 2009), ¶ 65 ("replacing condenser tubes" at De Young Unit 3 between 1998 and 2007)<br><br>• *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, First Amend. Compl. (S.D. Ohio Oct. 13, 2006), ¶ 46 ("[r]eplacement of the air removal section of the Unit 1 condenser" in 1985, "[r]eplacement of the Unit 1 condenser tubes" in 1992, "[r]eplacement of the upper half of the Unit 2 condenser, all four quadrants" in 1989, "[r]eplacement of the Unit 3 condenser tubes" from 1986 through 1992, and "[r]eplacement of the Unit 4 air removal section of condenser tubes" in 1987 at J.M. Stuart Generating Station)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 219 (modifications at |

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| | Waukegan Unit 8 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), see NOV issued by NOV issued by EPA Region 5 to Midwest Generation, LLC and Commonwealth Edison on July 31, 2007, ¶ 47 ("replaced condenser tubes" at Waukegan Unit 8 in 1996)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 72 ("replaced… thirty-year old condenser tubes" in Dunkirk Unit 1 in 1985), ¶ 203 ("replaced forty-seven year old condenser tubes" in Huntley Unit 63 in 1989), ¶ 324 ("replaced… condenser tubes" in Huntley Unit 67 in 1994), ¶ 357 ("replaced condenser tubes" in Huntley Unit 68 in 1993)<br><br>• *United States v. Ohio Edison Co., et al.*, No. 99-1181, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 42 ("replacing… superheater control condenser tubes of Sammis Unit 4 in 1990")<br><br>• *Sierra Club, et al. v. PPL Montana LLC, et al.*, No. 13-32, Compl. (D. Mont. Mar. 6, 2013), ¶ 79 ("replacing… the condenser" in Colstrip Unit 1 in 2012)<br><br>• *United States v. Wisconsin Power & Light Co., et al.*, No. 13-266, Compl. (W.D. Wis. Apr. 22, 2013), ¶ 57 ("replacement of the… condenser tubes at Edgewater Unit 5 in 2008")<br><br>• NOI from Sierra Club to Wisconsin Power and Light Company *et al.*, dated Oct. 10, 2009, at 5 (condenser retubing at Nelson Dewey Unit 2 in 2000) |
| FD or ID Fan | • *United States v. City of Akron, Ohio & Akron Energy Systems LLC*, No. 14-884, Compl. (N.D. Ohio Apr. 24, 2014), ¶ 110 ("replacing, rebuilding, and/or repairing… certain fans, including the induced draft fan and its drives, [and] the forced draft fan" at Akron Unit 32 in 1995 to 1996)<br><br>• Second Amend. NOV issued by EPA Region 7 to Ameren Missouri on May 27, 2011, ¶ 55 ("replaced ID (induced draft) fan" on Rush Island Unit 1 in 2001 to 2002)<br><br>• *United States v. Cinergy Corp.*, No. 99-1693, Compl. (S.D. Ind. Nov. 3, 1999), ¶ 44 ("replacement of the Unit 1 and Unit 2 forced draft fans in 1988 and 1990" at Cayuga facility)**;** First Amend. Compl. of Plaintiff Intervenors (S.D. Ind. Jun 30, 2006), ¶ 182 ("replacement of the induced draft fan components" at Beckjord Unit 4 between 1988 and 1989) |

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| | • NOV issued by EPA Region 5 to Indianapolis Power and Light Company on Sept. 29, 2009, Appendix A ("upgrade of the induced draft fan" on Harding Street Units 5 and 6 in 1991 to 1992)<br><br>• NOV issued by EPA Region 7 to Nebraska Public Power District on Dec. 8, 2008, ¶ 1 (replacement of induced draft fan at Gerald Gentleman Unit 1 in 1991)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 71 ("upgraded the capacity of the Unit's induced draft fans" at Dunkirk Unit 1 in 1983), ¶ 101 ("upgraded the capacity of the Unit's induced draft fans" at Dunkirk Unit 2 in 1982), ¶ 103 ("replaced steam drum connecting tubes and thirty-year old fluid drive couplings in the induced draft fans" at Dunkirk Unit 2 in 1989), ¶ 136 ("upgraded the induced draft fans" in Dunkirk Unit 3 in 1986), ¶ 170 ("upgraded the induced draft fans to increase generating capacity" at Dunkirk Unit 4 in 1987), ¶ 356 ("upgraded the induced draft fans" at Huntley Unit 68 in 1989)<br><br>• NOV issued by EPA Region 5 to the City of Painesville, Painesville Municipal Electric Plant on Aug. 18, 2009, Appendix A ("installation of an ID fan" at Units 3 and 4 in 1985)<br><br>• *Sierra Club, et al. v. PPL Montana LLC, et al.*, No. 13-32, Compl. (D. Mont. Mar. 6, 2013), ¶ 79 ("replacing 3 Induced Draft fans (or substantial portion of these components)" at Colstrip Unit 1 in 2012)<br><br>• NOV issued by EPA Region 5 to Richmond Power and Light on March 26, 2009, ¶ 38 ("[r]eplacement of ID/FD fan and motor" at Whitewater Valley Unit 1 in 1998)<br><br>• *United States v. Wisconsin Electric*, No. 03-371, Compl. (E.D. Wis. Apr. 29, 2003), ¶ 41 ("replacement of… induced draft fans" at Oak Creek facility)<br><br>• *United States v. Wisconsin Power & Light Co., et al.*, No. 13-266, Compl. (W.D. Wis. Apr. 22, 2013), ¶ 47 ("increase in forced draft fan capacity and total air flow to the boiler" at Nelson Dewey Unit 1 in 2003)<br><br>• NOI from Sierra Club to Wisconsin Power and Light Company on Dec. 14, 2009, at 5 (relocated forced draft fan air inlet at Nelson Dewey Unit 1 in 2000) |

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| | • NOV issued by EPA Region 5 to American Municipal Power-Ohio, Inc., March 27, 2009, Appendix A ("[r]epairs to breeching and ID fans" at Gorsuch Unit 2 in 1990)<br><br>• NOI from State of New York, *et al.* to Allegheny Energy, Inc. dated May 20, 2004, at 3-4 (replacement of the forced draft fan wheel at Fort Martin Unit 1 in 1996; replacement of the induced draft fan wheels at Pleasants Unit 1 in 1988; replacement of induced draft fan wheels at Pleasants Unit 2 in 1987)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 119 (modifications at Joliet Unit 6 in 1996 "described in the NOV issued to Defendant on July 31, 2007"); see NOV issued by EPA Region 5 to Midwest Generation, LLC, July 31, 2007, ¶ 38 (replaced 10 fan motors at Joliet Unit 6 in 1996)<br><br>• *United States v. AEP, et al.,* No. 99-1182, Second Amend. Compl. (S.D. Ohio Sept. 16, 2004), ¶ 140 ("upgrade of the primary air fan motors" at Cardinal Units 1 and 2 in 1988), ¶ 170 ("upgrade of the primary air fan motors" at Muskingum River Unit 5 in 1988) |
| Pulverizer | • *United States v. AEP, et al.*, No. 99-1182, Second Amend. Compl. (S.D. Ohio Sept. 16, 2004), ¶ 140 ("replacement of all five pulverizers" at Cardinal Unit 1 and "replacement of four pulverizers" at Cardinal Unit 2 from 1978 through 1980), ¶ 170, 174 ("replacement of five pulverizers" at Muskingum River Unit 5 from 1978 through 1980), ¶ 205 ("conversion and redesign of the #15 MBF pulverizer to an MPS-89 pulverizer" at Mitchell Unit 1 in 1990)<br><br>• *Dine Citizens, et al. v. Arizona Public Service Co., et al.*, No. 11-889, Compl. (D. N.M. Oct. 4, 2011), ¶ 48 ("replaced approximately 18 pulverizers" at Four Corners Units 4 and 5 in 1985 and 1986), ¶ 56 ("replacement and upgrade of pulverizers associated with the boiler by replacing and/or upgrading the classifiers" at Four Corners Unit 5 post-2007), ¶ 58 ("upgrade of the capacities of the pulverizers associated with the boiler" and "upgrade of the pulverizers associated with the boiler by replacing and/or upgrading the classifiers" at Four Corners Unit 4 post-2007)<br><br>• *United States v. Cinergy Corp.*, No. 99-1693, Third Amend. Compl. (S.D. Ind. June 29, 2006), ¶ 127 ("replacement of the Unit 1 pulverizer" in 1998 and "replacement of the Unit 3 pulverizer in |

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| | 1999" at the Gallagher facility)<br><br>• *Sierra Club v. City of Holland*, No. 08-1183, First Amend. Compl. (W.D. Mich. Mar. 10, 2009), ¶ 65 ("rebuilding the pulverizer at Unit 3" between 1988 and 2007 at De Young facility)<br><br>• *Sierra Club v. Dayton Power & Light, et al.*, No. 04-905, First Amend. Compl. (S.D. Ohio Oct. 13, 2006), ¶ 46 ("change from Babcock and Wilcox CR-77 to Babcock and Wilcox MPS-89 pulverizers" at J.M. Stuart Units 1-4 starting in 1978)<br><br>• NOV issued by EPA Region 4 to E.ON U.S. (parent of Kentucky Utilities) on April 26, 2006, ¶ 1 ("installation of newly designed and upgraded pulverizers" at E.W. Brown Unit 3 in 1997)<br><br>• NOI sent by New York and Pennsylvania to Homer City on July 20, 2010, at 3 ("replacement of the pulverizers at Unit 1 in 1982-83 and at Unit 2 in 1983-84" at Homer City facility)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶¶ 74, 107 ("upgraded the coal pulverizers" at Dunkirk Units 1 and 2 in 1998), ¶¶ 141, 172 ("upgraded the coal pulverizers" at Dunkirk Units 3 and 4 in 1999), ¶ 200 ("upgraded the pulverizers" at Huntley Unit 63 in 1984), ¶¶ 231, 262, 292 ("upgraded the pulverizers" at Huntley Units 64, 65, and 66 in 1983)<br><br>• NOV issued by EPA Region 5 to Northern Indiana Public Service Company on Sept. 29, 2004, ¶ 19(c) ("replacement and upgrade of pulverizers" at Rollin M. Schahfer Unit 15 in 1991)<br><br>• *United States v. Ohio Edison Co., et al.*, No. 99-1181, Compl. (S.D. Ohio Nov. 3, 1999), ¶ 42 ("replacing… coal pulverizer pipes of Sammis Unit 6 in 1992" and "replacing the coal pulverizers of Sammis Unit 6 in 1998")<br><br>• NOV issued by EPA Region 5 to the City of Painesville, Painesville Municipal Electric Plant on Aug. 18, 2009, Appendix A ("rebuilt south pulverizer" on Unit 5 in 1993 and "rebuilt north pulverizer" on Unit 5 in 1999)<br><br>• NOV issued by EPA Region 5 to Richmond Power and Light on March 26, 2009, ¶ 38 ("replacement of pulverizer and associated controls" at Whitewater Valley Unit 1 in 1998)<br><br>• *United States v. Salt River Project*, No. 08-1479, Compl. (D. Ariz. |

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| | Aug. 12, 2008), ¶ 31 ("modifications to the coal pulverizing systems and associated turbine steam path modifications" at Coronado Units 1 and 2 in 1998 to 2000)<br><br>• NOI from State of New York, *et al.* to Allegheny Energy, Inc. dated May 20, 2004, at 3-4 (replacement of the pulverizers at Fort Martin Unit 2 in 1987; pulverizer upgrades at Harrison Unit 1 in 1996)<br><br>• NOV issued by EPA Region 7 to Ameren Missouri, May 27, 2011, ¶ 54 ("upgraded coal mill" at Meramec Unit 3 in 2002 to 2003 and at Meramec Unit 4 in 2001 to 2002)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 87 ("upgraded the coal mills #3 and #4" on Genoa Unit 3 in 1997)<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 71 ("replaced the coal mill" at Dunkirk Unit 1 in 1983) |
| Condensate Pump | • *United States v. City of Akron, Ohio & Akron Energy Systems LLC*, No. 14-884, Compl. (N.D. Ohio Apr. 24, 2014), ¶ 110 ("replacing, rebuilding, and/or repairing… the steam piping system and condensate steam traps and associated piping" at Akron Unit 32 in 1995 to 1996)<br><br>• *Sierra Club v. Otter Tail Corp., et al.*, No. 08-1012, Compl. (D. S.D. June 10, 2008), ¶ 54 ("addition of a condensate return line" to Big Stone facility in 2001) |
| Flue Gas Conditioning System | • NOI from Sierra Club to Dayton Power and Light Company, dated July 21, 2004, at 4 (added Wahlco SO3 flue gas conditioning system, date and unit not specified) |
| Selective Catalytic Reduction | • NOI from Sierra Club to Dayton Power and Light Company, dated July 21, 2004, at 4 (installed Selective Catalytic Reduction at J.M. Stuart facility, date and unit not specified)<br><br>• *Conservation Law Foundation, Inc. v. Public Service Co. of New Hampshire*, No. 11-353, First Amend. Compl. (D.N.H. Dec. 4, 2013), ¶ 62 ("installing… selective catalytic reducer ("SCR") catalyst" and installing "SCR sub-girt, insulation, and lagging" and SCR expansion joints at Merrimack 2 in 2008) |

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| Ash Handling System (5) | • *Environmental Defense, et al. v. Alcoa Inc.*, No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶ 52 ("significant work on the ash handling system for Sandow Units 1, 2 and 3" in 1985 to 1986 including "changing the bottom ash transport lines, changing the fly ash removal lines and instrumentation, installation of the slag tank instrumentation and agitation nozzles, and changing the ash waster recycle pumps and valves")<br><br>• *New York v. Niagara Mohawk Power Corp., et al.*, No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 321 ("replaced… the bottom ash system" at Huntley Unit 67 in 1982), ¶ 352 ("replaced… the bottom ash system" at Huntley Unit 68 in 1982) |
| Neural Network Optimization System Upgrade | • *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ 82 ("installed a neural network optimization system upgrade" at the Madgett Unit in 1999) |
| ESP/Precipitator | • NOV issued by EPA Region 7 to Ameren Missouri, May 27, 2011, ¶ 54 ("installed new electrostatic precipitator ducts" at Meramec Unit 3 in 2000)<br><br>• *Sierra Club v. City of Holland*, No. 08-1183, First Amend. Compl. (W.D. Mich. Mar. 10, 2009), ¶ 65 ("rebuilding the precipitator" at De Young Unit 4 between 1988 and 2007)<br><br>• *United States v. City of Akron, Ohio & Akron Energy Systems LLC*, No. 14-884, Compl. (N.D. Ohio Apr. 24, 2014), ¶ 110 ("replacing, rebuilding, and/or repairing.. the electrostatic precipitator ("ESP") including the insulators" at Akron Unit 32 in 1995 to 1996)<br><br>• *United States v. DTE Energy Co., et al.*, No. 10-13101, First Amend. Compl. (E.D. Mich. Apr. 9, 2014), ¶ 65 ("upgrade of the electrostatic precipitator" at Monroe Unit 1 in 2006), ¶ 80 ("upgrade of the electrostatic precipitator" at Monroe Unit 2 in 2005), ¶ 85 ("upgrade of the electrostatic precipitator" at Monroe Unit 3 in 2004)<br><br>• NOV issued by EPA Region 5 to City of Painesville, Painesville Municipal Electric Plant, Aug. 18, 2009, Appendix A ("[i]nstalled an ESP" at Units 3 and 4 in 1985) |
| Controls | • NOV issued by EPA Region 5 to American Municipal Power-Ohio, Inc., March 27, 2009, Appendix A ("[b]urner control and management system" at Gorsuch facility in 1991) |

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| | • NOV issued by EPA Region 5 to Northern Indiana Public Service Company, Sept. 29, 2004, ¶ 19 ("replacement of the boiler control systems" at Michigan City Unit 12 in 1992 and at Rollin M. Schahfer Unit 14 in 1995)<br><br>• *Environmental Defense, et al. v. Alcoa Inc*., No. 01-881, Compl. (W.D. Tex. Dec. 26, 2001), ¶ 46 ("changing combustion controls" at Sandow Unit 1 in 1984 to 1986), ¶ 47 ("changing combustion controls" at Sandow Unit 2 in 1985), ¶ 48 ("changing combustion controls" at Sandow Unit 3 in 1984 to 1986)<br><br>• *New York v. Niagara Mohawk Power Corp., et al*., No. 02-24, Compl. (W.D.N.Y. Jan. 10, 2002), ¶ 199 ("upgraded… combustion controls" at Huntley Unit 63 in 1982 to 1983)<br><br>• *United States and Illinois v. Midwest Generation*, No. 09-5277, Compl. (N.D. Ill. Aug. 27, 2009), ¶ 101 (modifications at Fisk Unit 19 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 201 (modifications at Waukegan Unit 7 in 1996 "described in the NOV issued to Defendant on July 31, 2007"), ¶ 219 (modifications at Waukegan Unit 8 in 1996 "described in the NOV issued to Defendant on July 31, 2007"); see NOV issued by NOV issued by EPA Region 5 to Midwest Generation, LLC and Commonwealth Edison on July 31, 2007, ¶ 35 (installed new miscellaneous instrument and control microprocessor based boiler controls at Fisk Unit 19 in 1992 and new miscellaneous instrument and control panels to reduce equivalent forced outage rates at Fisk Unit 19 in 1996), ¶ 41 (installed new main instrument and control panels at Will County Units 1 and 2 in 1998), ¶ 44 (installed new main instrument and control panels at Powerton Unit 5 in 1992, installed new boiler instrument control system at Powerton Unit 6 in 1994), ¶ 47 (installed new panel miscellaneous instrument and control panels at Waukegan Unit 6 in 1994, installed new main instrument and control panels at Waukegan Unit 6 in 1996, installed new miscellaneous and control panel at Waukegan Units 7 and 8 in 1996, and installed new miscellaneous instrument and control panels at Waukegan Unit 8 in 1993)<br><br>• *United States v. City of Akron, Ohio & Akron Energy Systems LLC*, No. 14-884, Compl. (N.D. Ohio Apr. 24, 2014), ¶ 110 ("replacing, rebuilding, and/or repairing… boiler controls…" on Akron Unit 32 in 1995 to 1996)<br><br>• *Sierra Club v. Dairyland Power Cooperative*, No. 10-303, Compl. (W.D. Wis. June 8, 2010), ¶ ¶ 79 ("upgraded the… boiler controls on Alma units 1, 2, and 3" in 2002), ¶ 83 ("upgraded the boiler |

| Equipment | Action |
| --- | --- |
| | controls on the Madgett Unit” in 2001 to 2005), ¶ 86 (“upgraded the boiler controls on Genoa Unit 3” in 1996 to 1999) |

# Appendix B

## Building Block 2 Related

**Thomas Fitzhugh NGCC**
**(Data from Annual EIA-923 and EIA-860 Reports)**

| | | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CA - Oil | Net Gen (annual) | 0 | 0 | 0 | NL | NL | 0 | 2,446 | 0 | 0 | NL | NL |
| CA - Gas | Net Gen (annual) | 654 | 27,901 | 23,286 | 20,878 | 15,656 | 8,402 | 26,239 | 0 | 0 | 0 | 0 |
| CT - Oil | Net Gen (annual) | 698 | 51 | 1 | 0 | 0 | 40 | 7,124 | 0 | 10,435 | NL | NL |
| CT - Gas | Net Gen (annual) | 3,426 | 86,507 | 70,127 | 61,609 | 46,182 | 26,657 | 76,415 | 268,162 | 188,801 | 14,596 | 67,411 |
| SUM: | Net Gen (annual) | 4,778 | 114,459 | 93,414 | 82,487 | 61,838 | 35,099 | 112,224 | 268,162 | 199,236 | 14,596 | 67,411 |
| | | | | | | | | | | | | |
| CA - Oil | Net Gen (mo. max) | 0 | 0 | 0 | NL | NL | 0 | 998 | 0 | 0 | NL | NL |
| CA - Gas | Net Gen (mo. max) | 654 | 13,696 | 13,027 | 7,754 | 6,142 | 6,277 | 10,704 | 0 | 0 | 0 | 0 |
| CT - Oil | Net Gen (mo. max) | 0 | 0 | 0 | 0 | 0 | 0 | 2,906 | 0 | 1,233 | NL | NL |
| CT - Gas | Net Gen (mo. max) | 2,870 | 38,230 | 39,510 | 21,448 | 17,402 | 17,580 | 31,173 | 36,252 | 24,462 | 2,084 | 28,805 |
| SUM: | Net Gen (mo. max) | 3,524 | 51,926 | 52,537 | 29,202 | 23,544 | 23,857 | 45,782 | 36,252 | 25,695 | 2,084 | 28,805 |
| | | | | | | | | | | | | |
| CA - Oil | Heat Input | 0 | 0 | 0 | NL | NL | 0 | 0 | 0 | 0 | NL | NL |
| CA - Gas | Heat Input | 0 | 0 | 0 | 0 | 0 | 1,325 | 0 | 0 | 0 | 0 | 0 |
| CT - Oil | Heat Input | 7,271 | 858 | 86 | 0 | 0 | 513 | 88,761 | 0 | 96,578 | NL | NL |
| CT - Gas | Heat Input | 43,118 | 1,072,461 | 874,405 | 795,832 | 591,964 | 338,725 | 952,088 | 2,399,140 | 1,720,320 | 134,381 | 678,283 |
| SUM: | Heat Input | 50,389 | 1,073,319 | 874,491 | 795,832 | 591,964 | 340,563 | 1,040,849 | 2,399,140 | 1,816,898 | 134,381 | 678,283 |
| | | | | | | | | | | | | |
| CA - Oil | I/S Months | 0 | 0 | 0 | NL | NL | 0 | 7 | 0 | 0 | NL | NL |
| CA - Gas | I/S Months | 1 | 4 | 4 | 5 | 5 | 2 | 7 | 0 | 12 | 0 | 0 |
| CT - Oil | I/S Months | 1 | 1 | 1 | 0 | 0 | 1 | 7 | 0 | 12 | NL | NL |
| CT - Gas | I/S Months | 2 | 7 | 6 | 6 | 5 | 6 | 7 | 12 | 12 | 12 | 8 |
| SUM: | I/S Months | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |

| | | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SUM: | Net Gen (annual) | 4,778 | 114,459 | 93,414 | 82,487 | 61,838 | 35,099 | 112,224 | 268,162 | 199,236 | 14,596 | 67,411 | |
| SUM: | Heat Input (annual) | 50,389 | 1,073,319 | 874,491 | 795,832 | 591,964 | 340,563 | 1,040,849 | 2,399,140 | 1,816,898 | 134,381 | 678,283 | |
| SUM: | Net Gen (mo. max) | 3,524 | 51,926 | 52,537 | 29,202 | 23,544 | 23,857 | 45,782 | 36,252 | 25,695 | 2,084 | 28,805 | |
| | | | | | | | | | | | | | **Ave** |
| 185 * 8784 | Cap Factor (Nameplate) | 0.29% | 7.0% | 5.7% | 5.1% | 3.8% | 2.2% | 6.9% | 16.5% | 12.3% | 0.9% | 4.1% | 5.9% |
| 165 * 8784 | Cap Factor (Summer) | 0.33% | 7.9% | 6.4% | 5.7% | 4.3% | 2.4% | 7.7% | 18.5% | 13.7% | 1.0% | 4.7% | 6.6% |
| | | | | | | | | | | | | | |
| 185 * 30 days | Monthly Cap Factor (Name) | 2.6% | 39.0% | 39.4% | 21.9% | 17.7% | 17.9% | 34.4% | 27.2% | 19.3% | 1.6% | 21.6% | |
| 165 * 30 days | Monthly Cap Factor (Summer) | 3.0% | 43.7% | 44.2% | 24.6% | 19.8% | 20.1% | 38.5% | 30.5% | 21.6% | 1.8% | 24.2% | |
| | | | | | | | | | | | | | |
| | Net Heat Rate | 10,546 | 9,377 | 9,361 | 9,648 | 9,573 | 9,703 | 9,275 | 8,947 | 9,119 | 9,207 | 10,062 | |

| EIA860<br>Unit | EIA860<br>Type | EIA860<br>nameplate | EIA860<br>sumer |
|---|---|---|---|
| Unit 1 | CA | 59 | 62 |
| Unit 2 | CT | 126 | 103 |
| | Sum = | 185 | 165 |

| | | CF nameplate | CF summer |
|---|---|---|---|
| Net Gen (2003-13) = | 1,053,704 | 65% | 73% |
| Net Gen (2004-13; Last 10) = | 986,293 | 61% | 68% |
| | | | |
| 70% CF (Nameplate) = | 1,137,528 | | |
| 70% CF (Summer) = | 1,014,552 | | |

**Harry Oswald NGCC**
**(Data from Annual EIA-923 and EIA-860 Reports)**

| | | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CA - Gas | Net Gen | 65,484 | 75,327 | 206,152 | 95,568 | 32,033 | 32,631 | 0 | 0 | 0 | 0 | 37,045 |
| CT - Gas | Net Gen | 252,251 | 281,038 | 586,448 | 362,479 | 128,457 | 174,783 | 301,753 | 348,972 | 0 | 0 | 165,672 |
| Sum | Net Gen | 317,735 | 356,365 | 792,600 | 458,047 | 160,490 | 207,414 | 301,753 | 348,972 | 0 | 0 | 202,717 |
| | | | | | | | | | | | | |
| CA - Gas | Mo Max Net Gen | 16,663 | 34,024 | 51,032 | 30,199 | 9,253 | 11,382 | 0 | 0 | 0 | 0 | 11,792 |
| CT - Gas | Mo Max Net Gen | 67,716 | 124,700 | 129,636 | 118,013 | 36,865 | 73,314 | 106,044 | 102,892 | 0 | 0 | 45,844 |
| Sum | Mo Max Net Gen | 84,379 | 158,724 | 180,668 | 148,212 | 46,118 | 84,696 | 106,044 | 102,892 | 0 | 0 | 57,636 |
| | | | | | | | | | | | | |
| CA - Gas | I/S Months | 7 | 7 | 11 | 8 | 7 | 5 | 0 | 0 | 0 | 0 | 9 |
| CT - Gas | I/S Months | 7 | 7 | 11 | 8 | 7 | 5 | 7 | 6 | 0 | 0 | 9 |
| Sum | I/S Months | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | | | | | | | | | | | | |
| CA - Gas | HI | 0 | 0 | 6,299,697 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CT - Gas | HI | 2,719,263 | 3,041,028 | 6,299,693 | 3,944,970 | 1,392,581 | 1,939,413 | 2,600,828 | 2,948,077 | 0 | 0 | 1,698,789 |
| Sum | HI | 2,719,263 | 3,041,028 | 12,599,390 | 3,944,970 | 1,392,581 | 1,939,413 | 2,600,828 | 2,948,077 | 0 | 0 | 1,698,789 |

| | | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sum | Net Gen | 317,735 | 356,365 | 792,600 | 458,047 | 160,490 | 207,414 | 301,753 | 348,972 | 0 | 0 | 202,717 | |
| Sum | Mo Max Net Gen | 84,379 | 158,724 | 180,668 | 148,212 | 46,118 | 84,696 | 106,044 | 102,892 | 0 | 0 | 57,636 | |
| Sum | HI | 2,719,263 | 3,041,028 | 12,599,390 | 3,944,970 | 1,392,581 | 1,939,413 | 2,600,828 | 2,948,077 | 0 | 0 | 1,698,789 | |
| | | | | | | | | | | | | | **Ave** |
| 599.5 * 8784 | Cap Factor (Nameplate) | 1.60% | 3.01% | 3.43% | 2.81% | 0.88% | 1.61% | 2.01% | 1.95% | 0.00% | 0.00% | 1.09% | 1.7% |
| 548 * 8784 | Cap Factor (Summer) | 1.75% | 3.30% | 3.8% | 3.08% | 0.96% | 1.76% | 2.20% | 2.14% | 0.00% | 0.00% | 1.20% | 1.8% |
| | | | | | | | | | | | | | |
| 599.5 * 30 days | Monthly Cap Factor (Name) | 19.5% | 36.8% | 41.9% | 34.3% | 10.7% | 19.6% | 24.6% | 23.8% | 0.0% | 0.0% | 13.4% | |
| 548 * 30 days | Monthly Cap Factor (Summer) | 21.4% | 40.2% | 45.8% | 37.6% | 11.7% | 21.5% | 26.9% | 26.1% | 0.0% | 0.0% | 14.6% | |
| | | | | | | | | | | | | | |
| | Net Heat Rate | 8,558 | 8,533 | 15,896 | 8,613 | 8,677 | 9,350 | 8,619 | 8,448 | --- | --- | 8,380 | |

| Plant | Unit | Type | Nameplate | Summer | Year I/S |
|---|---|---|---|---|---|
| Harry L. Oswald | G1 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G2 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G3 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G4 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G5 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G6 | CT | 51 | 47 | 2002 |
| Harry L. Oswald | G7 | CT | 83.5 | 76 | 2002 |
| Harry L. Oswald | G8 | CA | 105 | 95 | 2002 |
| Harry L. Oswald | G9 | CA | 105 | 95 | 2002 |
| | | | 599.5 | 548 | |

| | | CF nameplate | CF summer |
|---|---|---|---|
| Net Gen (2003-13) = | 3,146,093 | 60% | 65% |
| Net Gen (2004-13; Last 10) = | 2,943,376 | 56% | 61% |
| 70% CF (Nameplate) = | 3,686,206 | | |
| 70% CF (Summer) = | 3,369,542 | | |

**Impact of UTO - Related Generation on the CO2 Emisison Rates Calculated in Building Block 2**

| State | Plant | 2012 CO2 (tons) | 2012 Net Generation (MWh) | 2012 CO2 Rate lb/MWh net | Useful Thermal Output (MWh) | Useful Thermal Output (CO2 tons) | 2012 Net Energy Output (Net Gen + UTO MWh) | 2012 CO2 Rate lb/MWh - net energy output | CO2 Emission Rate % Reduction lb/MWh (net gen) vs. lb/MWh (net gen + UTO) |
|---|---|---|---|---|---|---|---|---|---|
| Akransas | Pine Bluff Energy Center | 842,709 | 1,489,105 | 1,132 | 1,310,917 | 394,540 | 2,800,022 | 602 | -47% |
| Arizona | Yuma Cogeneration Associates | 45,946 | 83,912 | 1,095 | 19,361 | 8,614 | 103,273 | 890 | -19% |
| California | Greenleaf 1 Power Plant | 24,346 | 60,273 | 808 | 21,877 | 6,484 | 82,150 | 593 | -27% |
| California | Agnews Power Plant | 17,951 | 34,306 | 1,047 | 1,844 | 916 | 36,151 | 993 | -5% |
| California | Cardinal Cogen | 221,724 | 345,707 | 1,283 | 5,264 | 3,325 | 350,971 | 1,263 | -1% |
| California | Crockett Cogen Project | 857,754 | 1,675,114 | 1,024 | 799,779 | 277,189 | 2,474,893 | 693 | -32% |
| California | Foster Wheeler Martinez | 455,183 | 792,256 | 1,149 | 149,936 | 72,436 | 942,192 | 966 | -16% |
| California | Fresno Cogen Partners | 8,175 | 12,148 | 1,346 | 2 | 2 | 12,151 | 1,346 | 0% |
| California | Gilroy Power Plant | 122,229 | 241,338 | 1,013 | 1,830 | 920 | 243,168 | 1,005 | -1% |
| California | Goal Line LP | 100,059 | 190,913 | 1,048 | 28,216 | 12,884 | 219,129 | 913 | -13% |
| California | King City Power Plant | 500,960 | 501,229 | 1,999 | 492,088 | 248,175 | 993,317 | 1,009 | -50% |
| California | Los Medanos Energy Center | 1,601,644 | 3,594,416 | 891 | 435,411 | 173,053 | 4,029,827 | 795 | -11% |
| California | Mojave Cogen | 418,184 | 368,596 | 2,269 | 557,341 | 251,714 | 925,937 | 903 | -60% |
| California | Naval Station Energy Facility | 181,131 | 285,812 | 1,267 | 104,543 | 48,510 | 390,355 | 928 | -27% |
| California | North Island Energy Facility | 167,597 | 291,477 | 1,150 | 126,804 | 50,808 | 418,281 | 801 | -30% |
| California | OLS Energy Chino | 27,085 | 51,184 | 1,058 | 13,831 | 5,762 | 65,015 | 833 | -21% |
| Colorado | Thermo Power & Electric | 75,547 | 144,269 | 1,047 | 62,202 | 22,759 | 206,471 | 732 | -30% |
| Connecticut | Capital District Energy Center | 14,771 | 24,589 | 1,201 | 744 | 434 | 25,332 | 1,166 | -3% |
| Connecticut | Algonquin Windsor Locks | 37,188 | 110,479 | 673 | 29,297 | 7,795 | 139,776 | 532 | -21% |
| Florida | Auburndale Power Partners | 455,463 | 921,626 | 988 | 336,952 | 121,938 | 1,258,578 | 724 | -27% |
| Florida | Lake Cogen Ltd | 257,739 | 528,875 | 975 | 62,322 | 27,170 | 591,197 | 872 | -11% |
| Florida | Mulberry Cogeneration Facility | 208,456 | 402,963 | 1,035 | 42,671 | 19,961 | 445,635 | 936 | -10% |
| Florida | Orange Cogeneration Facility | 143,531 | 321,552 | 893 | 58,799 | 22,189 | 380,351 | 755 | -15% |
| Florida | Orlando Cogen LP | 406,990 | 807,098 | 1,009 | 50,422 | 23,931 | 857,520 | 949 | -6% |
| Florida | Pasco Cogen Ltd | 125,636 | 250,136 | 1,005 | 19,161 | 8,939 | 269,297 | 933 | -7% |
| Georgia | Mid-Georgia Cogeneration Facility | 189,209 | 380,258 | 995 | 83,815 | 34,173 | 464,073 | 815 | -18% |
| Illinois | Morris Cogeneration LLC | 468,230 | 627,592 | 1,492 | 727,383 | 251,357 | 1,354,975 | 691 | -54% |
| Indiana | Whiting Clean Energy | 1,404,480 | 1,962,480 | 1,431 | 543,314 | 304,524 | 2,505,794 | 1,121 | -22% |
| Louisiana | Louisiana 1 | 2,133,587 | 2,949,067 | 1,447 | 4,170,191 | 1,249,774 | 7,119,258 | 599 | -59% |
| Louisiana | Carville Energy LLC | 1,415,552 | 2,899,630 | 976 | 1,047,518 | 375,668 | 3,947,148 | 717 | -27% |
| Massachusetts | Bellingham Cogeneration Facility | 196,870 | 384,390 | 1,024 | 23,226 | 11,217 | 407,616 | 966 | -6% |
| Massachusetts | Kendall Square Station | 717,226 | 1,346,268 | 1,066 | 199 | 106 | 1,346,467 | 1,065 | 0% |
| Massachusetts | Lowell Cogeneration Company LP | 2,470 | 2,735 | 1,806 | 2,900 | 1,271 | 5,635 | 877 | -51% |
| Massachusetts | Masspower | 428,435 | 870,195 | 985 | 5,607 | 2,743 | 875,802 | 978 | -1% |
| Massachusetts | Pittsfield Generating LP | 156,284 | 292,164 | 1,070 | 3,052 | 1,616 | 295,216 | 1,059 | -1% |
| Michigan | Dearborn Industrial Generation | 1,526,968 | 2,883,435 | 1,059 | 2,400,582 | 693,717 | 5,284,017 | 578 | -45% |
| Michigan | Michigan Power LP | 568,477 | 1,050,504 | 1,082 | 2,173 | 1,173 | 1,052,677 | 1,080 | 0% |
| Michigan | Midland Cogeneration Venture | 3,458,764 | 6,237,051 | 1,109 | 1,875,036 | 799,462 | 8,112,086 | 853 | -23% |
| Minnesota | LSP-Cottage Grove LP | 256,399 | 500,409 | 1,025 | 97,924 | 41,963 | 598,333 | 857 | -16% |
| Nevada | Nevada Cogen Assoc#1 GarnetVly | 115,660 | 217,020 | 1,066 | 53,347 | 22,821 | 270,367 | 856 | -20% |
| Nevada | Nevada Cogen Associates 2 Black Mountain | 123,956 | 224,738 | 1,103 | 95,038 | 36,840 | 319,777 | 775 | -30% |

**Impact of UTO - Related Generation on the CO2 Emisison Rates Calculated in Building Block 2**

| State | Plant | 2012 CO2 (tons) | 2012 Net Generation (MWh) | 2012 CO2 Rate lb/MWh net | Useful Thermal Output (MWh) | Useful Thermal Output (CO2 tons) | 2012 Net Energy Output (Net Gen + UTO MWh) | 2012 CO2 Rate lb/MWh - net energy output | CO2 Emission Rate % Reduction lb/MWh (net gen) vs. lb/MWh (net gen + UTO) |
|---|---|---|---|---|---|---|---|---|---|
| Nevada | Saguaro Power | 410,764 | 714,805 | 1,149 | 49,651 | 26,679 | 764,456 | 1,075 | -6% |
| New Jersey | Bayonne Plant Holding LLC | 312,185 | 569,421 | 1,096 | 399,956 | 128,805 | 969,377 | 644 | -41% |
| New Jersey | Linden Cogen Plant | 2,158,589 | 4,026,492 | 1,072 | 1,380,961 | 551,263 | 5,407,453 | 798 | -26% |
| New Jersey | Newark Bay Cogeneration Partnership LP | 441,514 | 595,271 | 1,483 | 72,298 | 47,816 | 667,569 | 1,323 | -11% |
| New Jersey | Parlin Power Plant | 88,120 | 145,077 | 1,215 | 28 | 17 | 145,105 | 1,215 | 0% |
| New Jersey | Pedricktown Cogeneration Company LP | 208,378 | 412,162 | 1,011 | 21,924 | 10,524 | 434,086 | 960 | -5% |
| New York | Brooklyn Navy Yard Cogeneration | 958,594 | 1,672,162 | 1,147 | 919,984 | 340,216 | 2,592,145 | 740 | -35% |
| New York | Fortistar North Tonawanda | 39,368 | 75,159 | 1,048 | 9,769 | 4,528 | 84,928 | 927 | -12% |
| New York | Indeck Corinth Energy Center | 316,819 | 655,745 | 966 | 907 | 438 | 656,652 | 965 | 0% |
| New York | Indeck Olean Energy Center | 69,525 | 127,365 | 1,092 | 5,665 | 2,961 | 133,030 | 1,045 | -4% |
| New York | Indeck Oswego Energy Center | 13,835 | 25,266 | 1,095 | 2,969 | 1,455 | 28,235 | 980 | -11% |
| New York | Indeck Silver Springs Energy Center | 36,036 | 65,806 | 1,095 | 2,587 | 1,363 | 68,393 | 1,054 | -4% |
| New York | Indeck Yerkes Energy Center | 31,003 | 53,725 | 1,154 | 2,559 | 1,410 | 56,284 | 1,102 | -5% |
| New York | Kennedy International Airport Cogen | 352,291 | 666,162 | 1,058 | 15,964 | 8,245 | 682,126 | 1,033 | -2% |
| New York | Lockport Energy Associates LP | 139,386 | 282,046 | 988 | 46,214 | 19,623 | 328,260 | 849 | -14% |
| New York | Nassau Energy Corp | 237,872 | 379,705 | 1,253 | 250,244 | 94,494 | 629,948 | 755 | -40% |
| New York | Selkirk Cogen | 864,584 | 1,664,983 | 1,039 | 111,753 | 54,381 | 1,776,736 | 973 | -6% |
| New York | Sithe Independence Station | 2,411,465 | 5,462,396 | 883 | 531,871 | 213,969 | 5,994,267 | 805 | -9% |
| New York | Sterling Power Plant | 18,239 | 37,840 | 964 | 1,048 | 492 | 38,888 | 938 | -3% |
| Oklahoma | PowerSmith Cogeneration Project | 111,567 | 227,928 | 979 | 13,158 | 6,089 | 241,086 | 926 | -5% |
| Oregon | Klamath Cogeneration Plant | 982,068 | 2,224,837 | 883 | 123,816 | 51,773 | 2,348,653 | 836 | -5% |
| Pennsylvania | Grays Ferry Cogeneration | 629,556 | 867,705 | 1,451 | 2,748,259 | 478,485 | 3,615,964 | 348 | -76% |
| Pennsylvania | FPL Energy Marcus Hook LP | 2,217,425 | 4,603,574 | 963 | 824 | 397 | 4,604,399 | 963 | 0% |
| South Carolina | Columbia Energy Center | 24,436 | 51,407 | 951 | 14,671 | 5,425 | 66,078 | 740 | -22% |
| Texas | Baytown Energy Center | 2,054,091 | 4,623,424 | 889 | 211,802 | 89,977 | 4,835,226 | 850 | -4% |
| Texas | C R Wing Cogen Plant | 128,825 | 229,062 | 1,125 | 48,664 | 22,573 | 277,726 | 928 | -18% |
| Texas | Channel Energy Center LLC | 1,187,497 | 2,535,775 | 937 | 1,838,823 | 499,154 | 4,374,598 | 543 | -42% |
| Texas | Channelview Cogeneration Plant | 3,196,890 | 5,358,932 | 1,193 | 5,534,911 | 1,624,266 | 10,893,843 | 587 | -51% |
| Texas | Clear Lake Cogeneration Ltd | 314,707 | 515,034 | 1,222 | 495,717 | 154,346 | 1,010,751 | 623 | -49% |
| Texas | Deer Park Energy Center | 3,717,862 | 6,235,100 | 1,193 | 5,326,947 | 1,712,919 | 11,562,047 | 643 | -46% |
| Texas | Eastman Cogeneration Facility | 1,202,234 | 2,044,879 | 1,176 | 1,144,340 | 431,379 | 3,189,219 | 754 | -36% |
| Texas | Gregory Power Facility | 1,788,192 | 2,748,262 | 1,301 | 4,632,893 | 1,122,386 | 7,381,155 | 485 | -63% |
| Texas | Optim Energy Altura Cogen LLC | 1,973,688 | 2,794,319 | 1,413 | 179,978 | 119,430 | 2,974,297 | 1,327 | -6% |
| Texas | Oyster Creek Unit VIII | 1,537,669 | 2,302,324 | 1,336 | 427,615 | 240,859 | 2,729,939 | 1,127 | -16% |
| Texas | Pasadena Cogeneration | 1,923,668 | 4,636,293 | 830 | 824,581 | 290,470 | 5,460,874 | 705 | -15% |
| Texas | Sabine Cogen | 493,529 | 643,632 | 1,534 | 914,848 | 289,708 | 1,558,480 | 633 | -59% |
| Texas | SRW Cogen LP | 2,504,777 | 2,898,235 | 1,728 | 546,853 | 397,593 | 3,445,088 | 1,454 | -16% |
| Texas | Texas City Power Plant | 920,512 | 1,227,291 | 1,500 | 1,223,786 | 459,598 | 2,451,077 | 751 | -50% |
| Virginia | Hopewell Cogeneration | 684,730 | 1,246,207 | 1,099 | 145,646 | 71,652 | 1,391,853 | 984 | -10% |
| Washington | March Point Cogeneration | 803,259 | 1,075,813 | 1,493 | 1,181,538 | 420,440 | 2,257,351 | 712 | -52% |
| Washington | Ferndale Generating Station | 15,774 | 43,311 | 728 | 275 | 100 | 43,586 | 724 | -1% |
| Wisconsin | LSP-Whitewater LP | 465,158 | 955,086 | 974 | 160,189 | 66,812 | 1,115,275 | 834 | -14% |

**CORRECTED Ohio NGCC Calculations for Building Block 2**

| | EPA TSD App7 & eGRID | 2012 EIA860 | EPA TSA App7 & eGRID 2012 EIA923 p.1 | Corrected per 2012 AEP GADP210 Report | EPA Assumed Availability Hours | Corrected for Commissioning of Dresden & Fremont | = (net gen) / (nameplate * 8784 hrs) * (100) | = (correct net gen) / (nameplate * corrected hrs) * (100) | = (correct net gen) / (summer * corrected hrs) * (100) |
|---|---|---|---|---|---|---|---|---|---|
| Ohio NGCC Plant | Nameplate Capacity (MW) [EPA Calc] | Summer Capacity (MW) | 2012 Net Gen (MWh) [EPA Calc] | 2012 Net Gen (MWh) [Corrected] | 2012 Potential Operating Hours [EPA Calc] | 2012 Potential Operating Hours [Corrected] | 2012 Capacity Factor [EPA Calc] | 2012 Capacity Factor [Corrected & Nameplate] | 2012 Capacity Factor [Corrected & Summer] |
| Dresden (1), (2) | 678.3 | 540.0 | 470,486 | 2,599,011 | 8,784 | 8,064 | 8% | 48% | 60% |
| Fremont (3) | 739.5 | 667.3 | 2,582,396 | 2,582,396 | 8,784 | 8,328 | 40% | 42% | 46% |
| Hanging Rock | 1,288.20 | 1252.0 | 8,522,511 | 8,522,511 | 8,784 | 8,784 | 75% | 75% | 77% |
| Washington | 714.9 | 626.0 | 4,304,370 | 4,304,370 | 8,784 | 8,784 | 69% | 69% | 78% |
| Waterford | 921.6 | 810.0 | 5,027,420 | 5,027,420 | 8,784 | 8,784 | 62% | 62% | 71% |
| Ohio NGCC Total: | 4,342.5 | 3,895.3 | 20,907,183 | 23,035,708 | --- | --- | 54.8% | 61.7% | 68.7% |

(1) Dresden: EPA relies upon net generation reported to EIA. The 2012 submittal to EIA is incorrect as it only reflects net gen from November and December.
(2) Dresden: EPA's capacity factor calculation fails to consider that the unit was not commissioned until January 31, 2012. [Per APCO filing to the VaSCC on 3/20/12]
(3) Freemont: EPA's capacity factor calculation fails to consider that the unit was not commissioned until January 20, 2012. [Per AMP, Inc filing to the OPSB on 2/23/12]

## REDISPATCH BASED ON HISTORIC GENERATION

| | | | = (nameplate)* (8784 hrs/yr)* 70% | = (summer)* (8784 hrs/yr)* 70% | = (70% nameplate potential) - (baseline net gen) | = (70% summer potential) - (baseline net gen) | |
|---|---|---|---|---|---|---|---|
| | 2012 Baseline NGCC Capacity Factor | 2012 Baseline NGCC Net Gen (MWh) | NGCC Net Gen POTENTIAL at 70% Cap Factor Nameplate Basis (MWh) [EPA Calc] | NGCC Net Gen POTENTIAL at 70% Cap Factor Summer Basis (MWh) | Redispatched NGCC Net Gen Nameplate Basis (MWh) | Redispatched NGCC Net Gen Summer Basis (MWh) | |
| EPA Calcuation [Nameplate & Uncorrected Data] | 54.8% | 20,907,183 | 26,701,164 | | 5,793,981 | | = EPA calculated redispatch |
| Corrected Generation Data & Nameplate Capacity | 61.7% | 23,035,708 | 26,701,164 | | 3,665,456 | | |
| Corrected Generation Data & Summer Capacity | 68.7% | 23,035,708 | | 23,951,421 | | 915,713 | = 84% reduction from EPA calculated redispatch |

## REDISPATCH BASED ON HISTORIC CAPACITY FACTOR

| | | = (70%) - (2012 capacity factor) | = (nameplate) * (8784 hrs/yr)* (redispatch delta capacity factor) | = (summer) * (8784 hrs/yr)* (redispatch delta capacity factor) | |
|---|---|---|---|---|---|
| | 2012 Baseline NGCC Capacity Factor | Redispacth Delta from 2012 baseline to achieve a 70% Cap Factor | Redispatched NGCC Net Gen Nameplate Basis (MWh) | Redispatched NGCC Net Gen Summer Basis (MWh) | |
| EPA Calcuation [Nameplate & Uncorrected Data] | 54.8% | 15.2% | 5,793,981 | | = EPA calculated redispatch |
| Corrected Data & Nameplate Capacity | 61.7% | 8.3% | 3,155,849 | | |
| Corrected Data & Summer Capacity | 68.7% | 1.3% | | 439,452 | = 92% reduction from EPA calculated redispatch |

The historic capacity factor approach is more accurate for calculating redispatch as it assumes that Dresden and Fremont would have been available to operate year-round.
The historic generation approach is biased low as it does not account for the fact that Dresden and Fremont were not commissioned until late January.

Red Highlight = EPA Calculation Error
Green Highlight = Corrected Value

**CORRECTED Louisiana NGCC Building Block 2 Calculations**

| | | | | | | | | | | | CORRECTED CALULATIONS | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | EPA TSD App7 & eGRID | EPA TSD App7 & eGRID | EPA TSD App7 & eGRID | EPA CAMD | EPA TSD App7 & eGRID | EIA860 | EIA860 | EPA TSD App7 & eGRID | EPA TSD App7 & eGRID | EIA923 p.1 | EPA CAMD | EIA860 | EPA TSD App7 & eGRID | EPA TSD App7 & eGRID |
| Note | Plant Name | Gen ID | 2012 CO2 (tons) | 2012 CO2 (short tons) | Nameplate Capacity (MW) | Summer Capacity (MW) | Winter Capacity (MW) | 2012 Net Gen Electric (MWh) | 2012 Net Energy Output (MWh) | 2012 Net Gen (MWh) | Corrected 2012 CO2 (short tons) | Summer Capacity (MW) | Corrected 2012 Net Electric Gen (MWh) | Corrected 2012 Net Energy Output (MWh) |
| | Acadia Energy Center | CT11 | 317,510 | 539,360 | 212.0 | 170.6 | 204.7 | 737,301 | 737,301 | 2,984,005 | 539,360 | 170.6 | 737,301 | 737,301 |
| | Acadia Energy Center | CT12 | 317,510 | 561,188 | 212.0 | 170.6 | 204.7 | 737,301 | 737,301 | | 561,188 | 170.6 | 737,301 | 737,301 |
| | Acadia Energy Center | CT24 | 317,510 | 478,475 | 212.0 | 170.6 | 204.7 | 737,301 | 737,301 | | 478,475 | 170.6 | 737,301 | 737,301 |
| | Acadia Energy Center | CT25 | 317,510 | 481,795 | 212.0 | 170.6 | 204.7 | 737,301 | 737,301 | | 481,795 | 170.6 | 737,301 | 737,301 |
| | Acadia Energy Center | ST13 | 395,390 | --- | 264.0 | 190.3 | 211.8 | 918,149 | 918,149 | 1,801,498 | --- | 190.3 | 918,149 | 918,149 |
| | Acadia Energy Center | ST26 | 395,390 | --- | 264.0 | 190.3 | 211.8 | 918,149 | 918,149 | | --- | 190.3 | 918,149 | 918,149 |
| | PLANT TOTAL | | 2,060,818 | 2,060,818 | 1,376.0 | 1,063.0 | 1,242.4 | 4,785,503 | 4,785,503 | 4,785,503 | 2,060,818 | 1,063.0 | 4,785,503 | 4,785,503 |
| | Carville Energy LLC | CTG1 | 464,400 | 719,533 | 187.0 | 170.0 | 180.0 | 951,282 | 1,294,941 | 2,123,832 | 719,533 | 170.0 | 951,282 | 1,294,941 |
| | Carville Energy LLC | CTG2 | 464,400 | 696,019 | 187.0 | 170.0 | 180.0 | 951,282 | 1,294,941 | | 696,019 | 170.0 | 951,282 | 1,294,941 |
| | Carville Energy LLC | STG | 486,751 | --- | 196.0 | 133.0 | 140.0 | 997,066 | 1,357,265 | 775,798 | --- | 133.0 | 997,066 | 1,357,265 |
| | PLANT TOTAL | | 1,415,552 | 1,415,552 | 570.0 | 473.0 | 500.0 | 2,899,630 | 3,947,148 | 2,899,630 | 1,415,552 | 473.0 | 2,899,630 | 3,947,148 |
| | Coughlin Power Station | 6 | 84,209 | --- | 113.6 | 96.0 | 99.0 | 176,634 | 176,634 | 494,979 | --- | 96.0 | 176,634 | 176,634 |
| | Coughlin Power Station | 7 | 180,204 | --- | 243.1 | 174.0 | 185.0 | 377,991 | 377,991 | | --- | 174.0 | 377,991 | 377,991 |
| | Coughlin Power Station | U6CT | 139,878 | 194,734 | 188.7 | 163.0 | 175.0 | 293,406 | 293,406 | 939,863 | 194,734 | 163.0 | 293,406 | 293,406 |
| | Coughlin Power Station | U72 | 139,878 | 265,357 | 188.7 | 149.0 | 175.0 | 293,406 | 293,406 | | 265,357 | 149.0 | 293,406 | 293,406 |
| | Coughlin Power Station | U7CT | 139,878 | 223,957 | 188.7 | 150.0 | 175.0 | 293,406 | 293,406 | | 223,957 | 150.0 | 293,406 | 293,406 |
| | PLANT TOTAL | | 684,048 | 684,048 | 922.8 | 732.0 | 809.0 | 1,434,842 | 1,434,842 | 1,434,842 | 684,048 | 732.0 | 1,434,842 | 1,434,842 |
| | J Lamar Stall Unit | 6A | 431,511 | 759,793 | 184.0 | 160.0 | 184.0 | 1,047,674 | 1,047,674 | 2,238,033 | 759,793 | 160.0 | 1,047,674 | 1,047,674 |
| | J Lamar Stall Unit | 6B | 431,511 | 686,664 | 184.0 | 160.0 | 184.0 | 1,047,674 | 1,047,674 | | 686,664 | 160.0 | 1,047,674 | 1,047,674 |
| | J Lamar Stall Unit | 6STG | 600,363 | --- | 256.0 | 187.0 | 201.0 | 1,457,634 | 1,457,634 | 1,314,949 | --- | 187.0 | 1,457,634 | 1,457,634 |
| (1) | PLANT TOTAL | | 1,463,385 | 1,446,457 | 624.0 | 507.0 | 569.0 | 3,552,982 | 3,552,982 | 3,552,982 | 1,446,457 | 507.0 | 3,552,982 | 3,552,982 |
| (2) | Louisiana 1 | 1A | 120,779 | 134,070 | 23.0 | 18.0 | 18.0 | 166,942 | 403,010 | | n/a | n/a | n/a | n/a |
| (2) | Louisiana 1 | 2A | 328,204 | 129,178 | 62.5 | 55.0 | 55.0 | 453,647 | 1,095,136 | | n/a | n/a | n/a | n/a |
| (2) | Louisiana 1 | 3A | 330,829 | 133,827 | 63.0 | 55.0 | 55.0 | 457,276 | 1,103,897 | | n/a | n/a | n/a | n/a |
| (3) | Louisiana 1 | 4A | 530,377 | 700,690 | 101.0 | 10.0 | 100.0 | 733,093 | 1,769,739 | | n/a | n/a | n/a | n/a |
| (3) | Louisiana 1 | 5A | 823,398 | 1,035,821 | 156.8 | 154.4 | 151.4 | 1,138,109 | 2,747,476 | | n/a | n/a | n/a | n/a |
| | PLANT TOTAL | | 2,133,587 | 2,133,587 | 406.3 | 292.4 | 379.4 | 2,949,067 | 7,119,258 | --- | 0 | 0 | 0 | 0 |
| | Ouachita | CTG1 | 133,574 | 263,822 | 179.3 | 151.0 | 165.0 | 328,890 | 328,890 | 1,044,558 | 263,822 | 151.0 | 328,890 | 328,890 |
| | Ouachita | CTG2 | 133,574 | 210,654 | 179.3 | 152.0 | 166.0 | 328,890 | 328,890 | | 210,654 | 152.0 | 328,890 | 328,890 |
| | Ouachita | CTG3 | 133,574 | 198,907 | 179.3 | 158.0 | 164.0 | 328,890 | 328,890 | | 198,907 | 158.0 | 328,890 | 328,890 |
| | Ouachita | STG1 | 90,887 | --- | 122.0 | 104.0 | 103.0 | 223,785 | 223,785 | 613,467 | --- | 104.0 | 223,785 | 223,785 |
| | Ouachita | STG2 | 90,887 | --- | 122.0 | 105.0 | 104.0 | 223,785 | 223,785 | | --- | 105.0 | 223,785 | 223,785 |
| | Ouachita | STG3 | 90,887 | --- | 122.0 | 100.0 | 104.0 | 223,785 | 223,785 | | --- | 100.0 | 223,785 | 223,785 |
| | PLANT TOTAL | | 673,382 | 673,382 | 903.9 | 770.0 | 806.0 | 1,658,025 | 1,658,025 | 1,658,025 | 673,382 | 770.0 | 1,658,025 | 1,658,025 |
| (4) | Perryville Power Station | 2-CT | 257,334 | 11,207 | 186.2 | 156.0 | 168.0 | 561,814 | 561,814 | 1,623,280 | n/a | n/a | n/a | n/a |
| | Perryville Power Station | CT-1 | 274,886 | 545,806 | 198.9 | 160.0 | 166.0 | 600,133 | 600,133 | | 545,806 | 160.0 | 600,133 | 600,133 |
| | Perryville Power Station | CT-2 | 274,886 | 581,917 | 198.9 | 160.0 | 166.0 | 600,133 | 600,133 | | 581,917 | 160.0 | 600,133 | 600,133 |
| | Perryville Power Station | ST-1 | 331,825 | --- | 240.1 | 215.0 | 230.0 | 724,444 | 724,444 | 863,243 | --- | 215.0 | 724,444 | 724,444 |
| | PLANT TOTAL | | 1,138,930 | 1,138,930 | 824.1 | 691.0 | 730.0 | 2,486,523 | 2,486,523 | 2,486,523 | 1,127,723 | 535.0 | 1,924,709 | 1,924,709 |
| | Sterlington | 7A | 1,255 | 2,486 | 59.3 | 44.0 | 56.0 | 1,208 | 1,208 | CT = 3,797 | 2,486 | 44.0 | 1,208 | 1,208 |
| | Sterlington | 7B | 1,397 | --- | 66.0 | 44.0 | 55.0 | 1,344 | 1,344 | CA = 813 | --- | 44.0 | 1,344 | 1,344 |
| | Sterlington | 7C | 2,137 | 2,303 | 101.0 | 86.0 | 42.0 | 2,057 | 2,057 | | 2,303 | 86.0 | 2,057 | 2,057 |
| | PLANT TOTAL | | 4,789 | 4,789 | 226.3 | 174.0 | 153.0 | 4,610 | 4,610 | 4,610 | 4,789 | 174.0 | 4,610 | 4,610 |
| (5) | Washington Parish Energy Center | CTG1 | 0 | n/a | 200.0 | 172.0 | 188.0 | 0 | 0 | n/a | n/a | n/a | n/a | n/a |
| (5) | Washington Parish Energy Center | CTG2 | 0 | n/a | 200.0 | 172.0 | 188.0 | 0 | 0 | n/a | n/a | n/a | n/a | n/a |
| (5) | Washington Parish Energy Center | ST1 | 0 | n/a | 255.0 | 215.0 | 235.0 | 0 | 0 | n/a | n/a | n/a | n/a | n/a |
| | PLANT TOTAL | | 0 | 0 | 655.0 | 559.0 | 611.0 | 0 | 0 | n/a | 0 | 0 | 0 | 0 |
| | | Sum: | 9,574,492 | 9,557,564 | 6,508.4 | | | 19,771,182 | 24,988,890 | | 7,412,770 | 4,254.0 | 16,260,301 | 17,307,819 |
| | Baseline Capacity Factor (%) | | | | | | | 35% | | | | | 44% | |
| | CO2 Rate (lb/MWh-net): | | | | | | | 969 | 766 | | | | 912 | 857 |
| | | | | | EPA Calculated NGCC Redispatch (MWh): | | | 20,247,668 | | | Corrected Redispatch (MWh): | | 9,896,694 | |
| | | | | | | | | | | | Reduction from EPA Calc: | | -51% | |

(1) J.Lamar Stall: EPA Appendix 7 Plant Emissions incorrectly includes CO2 emissions from Gas Steam Boiler Unit 5A (Arsenal Hill), which overstates emissions by 38,301 to

(2) Louisiana 1 Units 1A, 2A, and 3A are natural gas steam boilers that should be excluded from EPA's NGCC calculation

(3) Louisiana 1 Units 4A and 5A are co-gen units that supply less than 1/3 of their generation to a utility distribution system, and thus are not an "affected source" subject to the proposed ru

(4) Perryville Unit 2-CT is a simple cycle unit that should be excluded from EPA's NGCC calculation

(5) Washintong Parish Energy Center has not commenced construction and should be excluded from EPA's NGCC calculation

**Summary of Data Quality Issues (in addition to those discussed in the body of the comments)**

| State | Plant | Issue | EPA Data | Correct Data |
|---|---|---|---|---|
| Ohio | Dresden | Incorrect 2012 Net Generation due error in EIA-923 report | 470,486 MWh | 2,599,011 MWh |
| Ohio | Cardinal | Discrepancy in 2012 CO2 data been EPA Appendix 7 and CAMD | 7,505,573 tons | 7,494,513 tons |
| Ohio | Gavin | Discrepancy in 2012 CO2 data been EPA Appendix 7 and CAMD | 18,195,132 tons | 18,190,141 tons |
| Ohio | Muskingum Rive | Discrepancy in 2012 CO2 data been EPA Appendix 7 and CAMD | 1,881,277 tons | 1,877,553 tons |
| Ohio | O H Hutchings | Discrepancy in 2012 CO2 data been EPA Appendix 7 and CAMD | 72,121 tons | 71,996 tons |
| Ohio | Zimmer | Discrepancy in 2012 CO2 data been EPA Appendix 7 and CAMD | 4,677,233 tons | 4,666,502 tons |
| Ohio | Existing Nuclear Units | Discrepancy in Ohio's Baseline Nuclear Capacity between Table 4.10 of EPA's GHG Abatement Measures TSD and 2012 EIA-860 Report | 2,150 MW | 2236.8 MW (nameplate)<br>2,134 MW (summer) |
| Louisiana | Arsenel Hill 5A | Incorrect 2012 CO2 data | 1,484,758 tons | 38,301 tons |
| Louisiana | Stall | Incorrect 2012 CO2 data | 1,463,385.1 tons | 1,446,457 tons |
| Louisiana | Louisiana 1 | Incorrectly included in NGCC calculations.  Units are gas steam boilers, not NGCC units | --- | --- |
| Louisiana | Perryville | Unit 2-CT is a simple cycle unit, not an NGCC unit | --- | --- |
| Louisiana | Washington Parish | Incorrectly included as existing NGCC capacity.  Unit has not been permitted or built | --- | --- |

# Appendix C

## Building Block 3 Related

**South Central RE Region (2012 vs. 2013)**

| | EIA923 "Total Electric Power" 2012 Total | EPA TSD EIA 923 2012 RE | EPA TSD Calc Verif. RE @20% | EPA TSD Calc Verif. Grth Factor | (2012 RE/Total) Calc 2012 %RE | | EPA TSD Calc Verif. Interim | EPA TSD Calc Verif. Final | |
|---|---|---|---|---|---|---|---|---|---|
| Arkansas | 65,005,678 | 1,660,370 | 13,001,136 | | 2.6% | Arkansas | 3,370,253 | 4,708,823 | |
| Kansas | 44,424,691 | 5,252,653 | 8,884,938 | | 11.8% | Kansas | 8,577,482 | 8,884,938 | 20% met |
| Louisiana | 103,407,706 | 2,430,042 | 20,681,541 | | 2.3% | Louisiana | 4,932,549 | 6,891,619 | |
| Nebraska | 34,217,293 | 1,346,762 | 6,843,459 | | 3.9% | Nebraska | 2,733,684 | 3,819,427 | |
| Oklahoma | 77,896,588 | 8,520,724 | 15,579,318 | | 10.9% | Oklahoma | 14,666,348 | 15,579,318 | 20% met |
| Texas | 429,812,510 | 34,016,697 | 85,962,502 | | 7.9% | Texas | 67,689,311 | 85,962,502 | 20% met |
| SUM | 754,764,465 | 53,227,248 | 150,952,893 | 8.3% | 7.1% | SUM | 101,969,627 | 125,846,626 | |

| Basis for Region Average | EPA TSD 2020 RPS |
|---|---|
| Arkansas | --- |
| Kansas | 20% |
| Louisiana | --- |
| Nebraska | --- |
| Oklahoma | --- |
| Texas | --- |
| Average = | 20% |

| | EIA923 "Total Electric Power" 2013 Total | EIA923 2013 RE | Calc RE @20% | Calc Grth Factor | Calc 2013 %RE | | Calc Interim | Calc Final | |
|---|---|---|---|---|---|---|---|---|---|
| Arkansas | 60,493,942 | 1,653,935 | 12,098,788 | | 2.7% | Arkansas | 2,934,309 | 3,869,477 | |
| Kansas | 48,645,149 | 9,486,233 | 9,729,030 | | 19.5% | Kansas | 9,729,030 | 9,729,030 | 20% met |
| Louisiana | 101,378,798 | 2,522,477 | 20,275,760 | | 2.5% | Louisiana | 4,475,223 | 5,901,482 | |
| Nebraska | 37,196,625 | 1,859,915 | 7,439,325 | | 5.0% | Nebraska | 3,299,748 | 4,351,381 | |
| Oklahoma | 73,576,312 | 11,220,222 | 14,715,262 | | 15.2% | Oklahoma | 14,715,262 | 14,715,262 | 20% met |
| Texas | 433,525,541 | 37,783,605 | 86,705,108 | | 8.7% | Texas | 66,864,167 | 86,705,108 | 20% met |
| SUM | 754,816,366 | 64,526,387 | 150,963,273 | 6.8% | 8.5% | SUM | 102,017,739 | 125,271,741 | |

lower than 2012

higher than 2012

| | 2012 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas | 1,660,370 | 1,798,989 | 1,949,181 | 2,111,912 | 2,288,229 | 2,479,266 | 2,686,252 | 2,910,519 | 3,153,509 | 3,416,786 | 3,702,042 | 4,011,114 | 4,345,990 | 4,708,823 | 3,370,253 |
| Kansas | 5,252,653 | 5,691,181 | 6,166,320 | 6,681,126 | 7,238,913 | 7,843,267 | 8,498,076 | 8,884,938 | 8,884,938 | 8,884,938 | 8,884,938 | 8,884,938 | 8,884,938 | 8,884,938 | 8,577,482 |
| Louisiana | 2,430,042 | 2,632,919 | 2,852,733 | 3,090,899 | 3,348,948 | 3,628,541 | 3,931,477 | 4,259,703 | 4,615,333 | 5,000,652 | 5,418,141 | 5,870,485 | 6,360,593 | 6,891,619 | 4,932,549 |
| Nebraska | 1,346,762 | 1,459,199 | 1,581,023 | 1,713,017 | 1,856,032 | 2,010,986 | 2,178,877 | 2,360,784 | 2,557,879 | 2,771,428 | 3,002,806 | 3,253,501 | 3,525,125 | 3,819,427 | 2,733,684 |
| Oklahoma | 8,520,724 | 9,232,093 | 10,002,851 | 10,837,958 | 11,742,785 | 12,723,153 | 13,785,369 | 14,936,266 | 15,579,318 | 15,579,318 | 15,579,318 | 15,579,318 | 15,579,318 | 15,579,318 | 14,666,348 |
| Texas | 34,016,697 | 36,856,644 | 39,933,689 | 43,267,627 | 46,879,906 | 50,793,762 | 55,034,373 | 59,629,020 | 64,607,260 | 70,001,117 | 75,845,290 | 82,177,376 | 85,962,502 | 85,962,502 | 67,689,311 |

| | 2013 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas | 1,653,935 | 1,765,685 | 1,884,986 | 2,012,348 | 2,148,315 | 2,293,469 | 2,448,431 | 2,613,863 | 2,790,472 | 2,979,014 | 3,180,296 | 3,395,177 | 3,624,577 | 3,869,477 | 2,934,309 |
| Kansas | 9,486,233 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 | 9,729,030 |
| Louisiana | 2,522,477 | 2,692,911 | 2,874,862 | 3,069,106 | 3,276,475 | 3,497,854 | 3,734,192 | 3,986,498 | 4,255,852 | 4,543,405 | 4,850,386 | 5,178,110 | 5,527,976 | 5,901,482 | 4,475,223 |
| Nebraska | 1,859,915 | 1,985,583 | 2,119,742 | 2,262,965 | 2,415,866 | 2,579,098 | 2,753,358 | 2,939,393 | 3,137,997 | 3,350,020 | 3,576,369 | 3,818,012 | 4,075,981 | 4,351,381 | 3,299,748 |
| Oklahoma | 11,220,222 | 11,978,333 | 12,787,666 | 13,651,684 | 14,574,079 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,715,262 | 14,701,144 |
| Texas | 37,783,605 | 40,336,510 | 43,061,905 | 45,971,445 | 49,077,573 | 52,393,570 | 55,933,618 | 59,712,855 | 63,747,441 | 68,054,629 | 72,652,840 | 77,561,735 | 82,802,306 | 86,705,108 | 66,864,167 |

Growth Factor = [[(Sum State (20%) RE) / (Sum 2012 State RE)]^(1/13)]-1

**East Central RE Region (2012 vs. 2013)**

| | EIA923 "Total Electric Power" 2012 Total | EPA TSD EIA923 2012 RE | EPA TSD Calc Verif. RE @15.8215% | EPA TSD Calc Verif. Grth Factor | Calc 2012 %RE |
|---|---|---|---|---|---|
| Delaware | 8,633,694 | 131,051 | 1,365,980 | | 1.5% |
| DC | 71,787 | 0 | 11,358 | | 0.0% |
| Maryland | 37,809,744 | 898,152 | 5,982,069 | | 2.4% |
| New Jersey | 65,263,408 | 1,280,715 | 10,325,650 | | 2.0% |
| Ohio | 129,745,731 | 1,738,622 | 20,527,721 | | 1.3% |
| Pennsylvania | 223,419,716 | 4,459,118 | 35,348,350 | | 2.0% |
| Virginia | 70,739,235 | 2,358,444 | 11,192,008 | | 3.3% |
| West Virginia | 73,413,405 | 1,296,563 | 11,615,102 | | 1.8% |
| SUM | 609,096,718 | 12,162,664 | 96,368,237 | 17.3% | 2.0% |

| | EPA TSD Calc Verif. Interim | EPA TSD Calc Verif. Final |
|---|---|---|
| Delaware | 561,909 | 1,038,351 |
| DC | 0 | 0 |
| Maryland | 3,728,926 | 5,982,069 |
| New Jersey | 5,491,354 | 10,147,466 |
| Ohio | 7,454,735 | 13,775,594 |
| Pennsylvania | 19,119,477 | 35,330,855 |
| Virginia | 8,608,808 | 11,192,008 |
| West Virginia | 5,559,307 | 10,273,036 |
| SUM | 50,524,515 | 87,739,379 |

| Basis for Region Average | EPA TSD 2020 RPS |
|---|---|
| Delaware | 19.00% |
| DC | 20.00% |
| Maryland | 18.00% |
| New Jersey | 21.909% |
| Ohio | 8.50% |
| Pennsylvania | 7.52% |
| Virginia | --- |
| West Virginia | --- |
| Average = | 15.82150% |

| | EIA923 "Total Electric Power" 2013 Total | EIA923 2013 RE | Calc RE @15.8215% | Calc Grth Factor | Calc 2013 %RE |
|---|---|---|---|---|---|
| Delaware | 7,615,925 | 122,201 | 1,204,954 | | 1.6% |
| DC | 60,215 | 0 | 9,527 | | 0.0% |
| Maryland | 35,487,421 | 933,663 | 5,614,642 | | 2.6% |
| New Jersey | 64,847,850 | 1,549,431 | 10,259,903 | | 2.4% |
| Ohio | 136,702,078 | 1,889,019 | 21,628,319 | | 1.4% |
| Pennsylvania | 227,682,932 | 5,714,430 | 36,022,855 | | 2.5% |
| Virginia | 77,184,922 | 2,845,399 | 12,211,812 | | 3.7% |
| West Virginia | 75,927,318 | 1,401,542 | 12,012,841 | | 1.8% |
| SUM | 625,508,662 | 14,455,685 | 98,964,853 | 15.9% | 2.3% |

| | Calc Interim | Calc Final | |
|---|---|---|---|
| Delaware | 469,738 | 836,602 | |
| DC | 0 | 0 | |
| Maryland | 3,511,235 | 5,614,642 | 15.8% met |
| New Jersey | 5,921,188 | 10,259,903 | 15.8% met |
| Ohio | 7,261,315 | 12,932,383 | |
| Pennsylvania | 21,656,186 | 36,022,855 | 15.8% met |
| Virginia | 9,495,684 | 12,211,812 | 15.8% met |
| West Virginia | 5,387,474 | 9,595,078 | |
| SUM | 53,702,820 | 87,473,276 | |

lower than 2012

higher than 2012

| | 2012 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Delaware | 131,051 | 153,669 | 180,191 | 211,290 | 247,757 | 290,517 | 340,658 | 399,452 | 468,394 | 549,235 | 644,028 | 755,181 | 885,519 | 1,038,351 | 561,909 |
| DC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maryland | 898,152 | 1,053,165 | 1,234,932 | 1,448,071 | 1,697,995 | 1,991,053 | 2,334,691 | 2,737,638 | 3,210,129 | 3,764,169 | 4,413,830 | 5,175,617 | 5,982,069 | 5,982,069 | 3,728,926 |
| New Jersey | 1,280,715 | 1,501,754 | 1,760,944 | 2,064,867 | 2,421,244 | 2,839,129 | 3,329,137 | 3,903,716 | 4,577,463 | 5,367,492 | 6,293,872 | 7,380,138 | 8,653,883 | 10,147,466 | 5,491,354 |
| Ohio | 1,738,622 | 2,038,692 | 2,390,552 | 2,803,140 | 3,286,937 | 3,854,232 | 4,519,438 | 5,299,452 | 6,214,090 | 7,286,586 | 8,544,185 | 10,018,835 | 11,747,996 | 13,775,594 | 7,454,735 |
| Pennsylvania | 4,459,118 | 5,228,721 | 6,131,151 | 7,189,333 | 8,430,147 | 9,885,114 | 11,591,196 | 13,591,732 | 15,937,543 | 18,688,219 | 21,913,638 | 25,695,734 | 30,130,587 | 35,330,855 | 19,119,477 |
| Virginia | 2,358,444 | 2,765,490 | 3,242,788 | 3,802,464 | 4,458,736 | 5,228,273 | 6,130,626 | 7,188,717 | 8,429,425 | 9,884,268 | 11,192,008 | 11,192,008 | 11,192,008 | 11,192,008 | 8,608,808 |
| West Virginia | 1,296,563 | 1,520,338 | 1,782,735 | 2,090,419 | 2,451,206 | 2,874,262 | 3,370,334 | 3,952,023 | 4,634,107 | 5,433,912 | 6,371,756 | 7,471,464 | 8,760,972 | 10,273,036 | 5,559,307 |

| | 2013 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Delaware | 122,201 | 141,691 | 164,288 | 190,489 | 220,869 | 256,095 | 296,938 | 344,294 | 399,204 | 462,871 | 536,691 | 622,285 | 721,529 | 836,602 | 469,738 |
| DC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maryland | 933,663 | 1,082,568 | 1,255,220 | 1,455,407 | 1,687,522 | 1,956,655 | 2,268,710 | 2,630,533 | 3,050,061 | 3,536,497 | 4,100,512 | 4,754,479 | 5,512,743 | 5,614,642 | 3,511,235 |
| New Jersey | 1,549,431 | 1,796,540 | 2,083,060 | 2,415,274 | 2,800,472 | 3,247,103 | 3,764,964 | 4,365,416 | 5,061,631 | 5,868,880 | 6,804,873 | 7,890,142 | 9,148,494 | 10,259,903 | 5,921,188 |
| Ohio | 1,889,019 | 2,190,287 | 2,539,603 | 2,944,629 | 3,414,251 | 3,958,769 | 4,590,130 | 5,322,183 | 6,170,986 | 7,155,161 | 8,296,295 | 9,619,422 | 11,153,567 | 12,932,383 | 7,261,315 |
| Pennsylvania | 5,714,430 | 6,625,791 | 7,682,499 | 8,907,735 | 10,328,377 | 11,975,589 | 13,885,505 | 16,100,022 | 18,667,719 | 21,644,923 | 25,096,944 | 29,099,508 | 33,740,416 | 36,022,855 | 21,656,186 |
| Virginia | 2,845,399 | 3,299,195 | 3,825,364 | 4,435,448 | 5,142,832 | 5,963,032 | 6,914,040 | 8,016,720 | 9,295,259 | 10,777,705 | 12,211,812 | 12,211,812 | 12,211,812 | 12,211,812 | 9,495,684 |
| West Virginia | 1,401,542 | 1,625,066 | 1,884,238 | 2,184,744 | 2,533,176 | 2,937,177 | 3,405,610 | 3,948,751 | 4,578,514 | 5,308,714 | 6,155,370 | 7,137,053 | 8,275,300 | 9,595,078 | 5,387,474 |

Growth Factor = [[(Sum State (20%) RE) / (Sum 2012 State RE)]^(1/13)]-1

**Southeast RE Region (2012 vs. 2013)**

| | EIA923 "Total Electric Power" 2012 Total | EPA TSD EIA923 2012 RE | EPA TSD Calc Verif. RE @10% | EPA TSD Calc Verif. Grth Factor | Calc 2012 %RE |
|---|---|---|---|---|---|
| Alabama | 152,878,688 | 2,776,554 | 15,287,869 | | 1.8% |
| Florida | 221,096,136 | 4,523,798 | 22,109,614 | | 2.0% |
| Georgia | 122,306,364 | 3,278,536 | 12,230,636 | | 2.7% |
| Kentucky | 89,949,689 | 332,879 | 8,994,969 | | 0.4% |
| Mississippi | 54,584,295 | 1,509,190 | 5,458,430 | | 2.8% |
| N. Carolina | 116,681,763 | 2,703,919 | 11,668,176 | | 2.3% |
| S. Carolina | 96,755,682 | 2,143,473 | 9,675,568 | | 2.2% |
| Tennessee | 77,724,264 | 836,458 | 7,772,426 | | 1.1% |
| SUM | 931,976,880 | 18,104,807 | 93,197,688 | 13.4% | 1.9% |

| | EPA TSD Calc Verif. Interim | EPA TSD Calc Verif. Final | |
|---|---|---|---|
| Alabama | 8,647,278 | 14,292,801 | |
| Florida | 13,971,137 | 22,109,614 | 10% met |
| Georgia | 9,392,695 | 12,230,636 | 10% met |
| Kentucky | 1,036,717 | 1,713,556 | |
| Mississippi | 4,272,197 | 5,458,430 | 10% met |
| N. Carolina | 8,135,750 | 11,668,176 | 10% met |
| S. Carolina | 6,534,613 | 9,675,568 | 10% met |
| Tennessee | 2,605,058 | 4,305,814 | |
| SUM | 54,595,444 | 81,454,595 | |

| Basis for Region Average | EPA TSD 2020 RPS |
|---|---|
| Alabama | --- |
| Florida | --- |
| Georgia | --- |
| Kentucky | --- |
| Mississippi | --- |
| N. Carolina | 10% |
| S. Carolina | --- |
| Tennessee | --- |
| Average = | 10% |

| | EIA923 "Total Electric Power" 2013 Total | EIA923 2013 RE | Calc RE @10% | Calc Grth Factor | Calc 2013 %RE |
|---|---|---|---|---|---|
| Alabama | 150,408,356 | 3,249,001 | 15,040,836 | | 2.2% |
| Florida | 219,724,535 | 4,617,727 | 21,972,453 | | 2.1% |
| Georgia | 120,796,051 | 3,609,045 | 12,079,605 | | 3.0% |
| Kentucky | 89,934,694 | 327,475 | 8,993,469 | | 0.4% |
| Mississippi | 52,890,105 | 1,508,578 | 5,289,010 | | 2.9% |
| N. Carolina | 124,921,684 | 2,946,855 | 12,492,168 | | 2.4% |
| S. Carolina | 94,919,263 | 1,959,591 | 9,491,926 | | 2.1% |
| Tennessee | 78,669,446 | 1,082,379 | 7,866,945 | | 1.4% |
| SUM | 932,264,133 | 19,300,651 | 93,226,413 | 12.9% | 2.1% |

| | Calc Interim | Calc Final | |
|---|---|---|---|
| Alabama | 9,593,777 | 15,040,836 | 10% met |
| Florida | 13,694,930 | 21,972,453 | 10% met |
| Georgia | 9,693,456 | 12,079,605 | 10% met |
| Kentucky | 973,557 | 1,581,775 | |
| Mississippi | 4,125,490 | 5,289,010 | 10% met |
| N. Carolina | 8,574,820 | 12,492,168 | 10% met |
| S. Carolina | 5,825,715 | 9,465,259 | |
| Tennessee | 3,217,831 | 5,228,131 | |
| SUM | 55,699,576 | 83,149,237 | |

lower than 2012

higher than 2012

| | 2012 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alabama | 2,776,554 | 3,149,528 | 3,572,603 | 4,052,510 | 4,596,883 | 5,214,381 | 5,914,827 | 6,709,365 | 7,610,632 | 8,632,966 | 9,792,631 | 11,108,072 | 12,600,217 | 14,292,801 | 8,647,278 |
| Florida | 4,523,798 | 5,131,479 | 5,820,789 | 6,602,694 | 7,489,632 | 8,495,713 | 9,636,940 | 10,931,468 | 12,399,889 | 14,065,563 | 15,954,987 | 18,098,217 | 20,529,346 | 22,109,614 | 13,971,137 |
| Georgia | 3,278,536 | 3,718,941 | 4,218,506 | 4,785,176 | 5,427,968 | 6,157,106 | 6,984,188 | 7,922,373 | 8,986,583 | 10,193,748 | 11,563,072 | 12,230,636 | 12,230,636 | 12,230,636 | 9,392,695 |
| Kentucky | 332,879 | 377,595 | 428,317 | 485,853 | 551,118 | 625,149 | 709,125 | 804,382 | 912,434 | 1,035,001 | 1,174,033 | 1,331,740 | 1,510,633 | 1,713,556 | 1,036,717 |
| Mississippi | 1,509,190 | 1,711,919 | 1,941,881 | 2,202,733 | 2,498,626 | 2,834,265 | 3,214,992 | 3,646,861 | 4,136,743 | 4,692,430 | 5,322,763 | 5,458,430 | 5,458,430 | 5,458,430 | 4,272,197 |
| N. Carolina | 2,703,919 | 3,067,136 | 3,479,144 | 3,946,496 | 4,476,628 | 5,077,973 | 5,760,095 | 6,533,848 | 7,411,538 | 8,407,128 | 9,536,455 | 10,817,485 | 11,668,176 | 11,668,176 | 8,135,750 |
| S. Carolina | 2,143,473 | 2,431,405 | 2,758,015 | 3,128,498 | 3,548,749 | 4,025,451 | 4,566,189 | 5,179,564 | 5,875,334 | 6,664,566 | 7,559,815 | 8,575,324 | 9,675,568 | 9,675,568 | 6,534,613 |
| Tennessee | 836,458 | 948,819 | 1,076,274 | 1,220,849 | 1,384,846 | 1,570,872 | 1,781,886 | 2,021,247 | 2,292,760 | 2,600,746 | 2,950,104 | 3,346,391 | 3,795,911 | 4,305,814 | 2,605,058 |

| | 2013 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alabama | 3,249,001 | 3,667,437 | 4,139,764 | 4,672,921 | 5,274,742 | 5,954,072 | 6,720,892 | 7,586,471 | 8,563,526 | 9,666,416 | 10,911,346 | 12,316,610 | 13,902,856 | 15,040,836 | 9,593,777 |
| Florida | 4,617,727 | 5,212,440 | 5,883,746 | 6,641,509 | 7,496,863 | 8,462,379 | 9,552,242 | 10,782,467 | 12,171,133 | 13,738,643 | 15,508,032 | 17,505,299 | 19,759,793 | 21,972,453 | 13,694,930 |
| Georgia | 3,609,045 | 4,073,851 | 4,598,519 | 5,190,759 | 5,859,272 | 6,613,883 | 7,465,680 | 8,427,179 | 9,512,509 | 10,737,617 | 12,079,605 | 12,079,605 | 12,079,605 | 12,079,605 | 9,693,456 |
| Kentucky | 327,475 | 369,650 | 417,257 | 470,995 | 531,654 | 600,125 | 677,415 | 764,659 | 863,138 | 974,301 | 1,099,781 | 1,241,421 | 1,401,302 | 1,581,775 | 973,557 |
| Mississippi | 1,508,578 | 1,702,867 | 1,922,177 | 2,169,733 | 2,449,171 | 2,764,598 | 3,120,649 | 3,522,555 | 3,976,222 | 4,488,316 | 5,066,363 | 5,289,010 | 5,289,010 | 5,289,010 | 4,125,490 |
| N. Carolina | 2,946,855 | 3,326,378 | 3,754,780 | 4,238,355 | 4,784,210 | 5,400,364 | 6,095,873 | 6,880,955 | 7,767,148 | 8,767,473 | 9,896,629 | 11,171,208 | 12,492,168 | 12,492,168 | 8,574,820 |
| S. Carolina | 1,959,591 | 2,211,965 | 2,496,843 | 2,818,409 | 3,181,390 | 3,591,118 | 4,053,616 | 4,575,677 | 5,164,975 | 5,830,168 | 6,581,031 | 7,428,597 | 8,385,320 | 9,465,259 | 5,825,715 |
| Tennessee | 1,082,379 | 1,221,778 | 1,379,130 | 1,556,747 | 1,757,239 | 1,983,552 | 2,239,012 | 2,527,373 | 2,852,871 | 3,220,290 | 3,635,029 | 4,103,181 | 4,631,627 | 5,228,131 | 3,217,831 |

Growth Factor = [[(Sum State (20%) RE) / (Sum 2012 State RE)]^(1/13)]-1

| | Virginia | WV | |
|---|---|---|---|
| Solar | 1,909,919 | 55,718 | GWh |
| Onshore | 4589 | 4952 | GWh |
| Hydro | 3657 | 4408 | GWh |
| Sum | 1,918,165 | 65,078 | GWh |

| | | | |
|---|---|---|---|
| Target RE (at SE Region Ave) = | 11,192,008 | 11,615,102 | MWh |
| Interim RE Goal = | 8,608,808 | 5,559,307 | |
| Final RE Goal = | 11,192,008 | 10,273,036 | |

**Impact of Changing RE Region (November 6, 2014)**

| | Region Ave (per RPS) | Region Growth Rate (per 2012) |
|---|---|---|
| East Central | 15.8215% | 17.259% |
| South Central | 20% | 8.349% |
| Southeast | 10% | 13.433% |

| | 2012 Total Generation | 2012 RE Generation |
|---|---|---|
| Arkansas | 65,005,678 | 1,660,370 |
| Louisiana | 103,407,706 | 2,430,042 |
| Virginia | 70,739,235 | 2,358,444 |
| West Virginia | 73,413,405 | 1,296,563 |

[=(Final Goal) / (State RE Target)]

| | East Central | South Central | Southeast | East Central | South Central | Southeast | East Central | South Central | Southeast | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | State Target RE | State Target RE | State Target RE | Interim Goal | Interim Goal | Interim Goal | Final Goal | Final Goal | Final Goal | | % of Base Region RE Target for State | % of SE Region RE Target for State |
| Arkansas | --- | 13,001,136 | 6,500,568 | --- | 3,370,253 | 4,848,761 | --- | 4,708,823 | 6,500,568 | higher | 36% | 100% |
| Louisiana | --- | 20,681,541 | 10,340,771 | --- | 4,932,549 | 7,282,579 | --- | 6,891,619 | 10,340,771 | higher | 33% | 100% |
| Virginia | 11,192,008 | --- | 7,073,923 | 8,608,808 | --- | 6,089,118 | 11,192,008 | --- | 7,073,923 | lower | 100% | 100% |
| West Virginia | 11,615,102 | --- | 7,341,340 | 5,559,307 | --- | 4,038,005 | 10,273,036 | --- | 6,674,286 | lower | 88% | 91% |

**RE Rates if Located in Southeast Region**

| | 2012 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Ave 2020-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas | 1,660,370 | 1,883,407 | 2,136,405 | 2,423,388 | 2,748,921 | 3,118,182 | 3,537,047 | 4,012,178 | 4,551,133 | 5,162,485 | 5,855,961 | 6,500,568 | 6,500,568 | 6,500,568 | 4,848,761 |
| Louisiana | 2,430,042 | 2,756,469 | 3,126,745 | 3,546,760 | 4,023,195 | 4,563,630 | 5,176,662 | 5,872,041 | 6,660,831 | 7,555,579 | 8,570,518 | 9,721,794 | 10,340,771 | 10,340,771 | 7,282,579 |
| Virginia | 2,358,444 | 2,675,253 | 3,034,619 | 3,442,258 | 3,904,656 | 4,429,168 | 5,024,137 | 5,699,028 | 6,464,577 | 7,073,923 | 7,073,923 | 7,073,923 | 7,073,923 | 7,073,923 | 6,089,118 |
| West Virginia | 1,296,563 | 1,470,730 | 1,668,293 | 1,892,394 | 2,146,599 | 2,434,951 | 2,762,037 | 3,133,061 | 3,553,925 | 4,031,322 | 4,572,849 | 5,187,119 | 5,883,903 | 6,674,286 | 4,038,005 |

**Comments related to Building Block 3**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Appendix 1 Goal Comp TSD | Appendix 1 Goal Comp TSD | EIA861 | Table 4-1 GHG Abate TSD | Table 4-1 GHG Abate TSD | Table 4-1 GHG Abate TSD | Calc | Calc | |
| EPA RE Region | State | State Generation as % of sales | 2012 Total MWh (sales x 1.0751) | 2012 Total MWh Sales | 2012 RE Gen (MWh) | 2012 Total Gen (MWh) | 2012 %RE Gen of Total Gen | 2012 %RE Gen of Sales | 2012 %RE Gen of Sales x 1.0751 | State |
| E.Central | Delaware | 45.09% | 12,384,433 | 11,519,331 | 131,051 | 8,633,694 | 1.5% | 1.1% | 1.1% | Delaware |
| E.Central | Maryland | 60.82% | 66,455,750 | 61,813,552 | 898,152 | 37,809,744 | 2.4% | 1.5% | 1.4% | Maryland |
| E.Central | New Jersey | 76.19% | 80,689,388 | 75,052,914 | 1,280,715 | 65,263,408 | 2.0% | 1.7% | 1.6% | New Jersey |
| E.Central | Ohio | 85.97% | 163,906,374 | 152,456,864 | 1,738,622 | 129,745,731 | 1.3% | 1.1% | 1.1% | Ohio |
| E.Central | Pennsylvania | 142.20% | 155,577,427 | 144,709,727 | 4,459,118 | 223,419,715 | 2.0% | 3.1% | 2.9% | Pennsylvania |
| E.Central | Virginia | 58.01% | 115,890,388 | 107,794,985 | 2,358,444 | 70,739,235 | 3.3% | 2.2% | 2.0% | Virginia |
| E.Central | West Virginia | 233.30% | 33,131,616 | 30,817,241 | 1296563 | 73,413,405 | 1.8% | 4.2% | 3.9% | West Virginia |
| E.Central | D.C. | | | | --- | 71,787 | | | | D.C. |
| | | | | | | | | | | |
| N.Central | Illinois | 126.99% | 154,319,858 | 143,540,004 | 8,372,660 | 197,565,363 | 4.2% | 5.8% | 5.4% | Illinois |
| N.Central | Indiana | 102.84% | 113,071,949 | 105,173,425 | 3,546,367 | 114,695,729 | 3.1% | 3.4% | 3.1% | Indiana |
| N.Central | Iowa | 113.03% | 49,141,853 | 45,709,100 | 14,183,424 | 56,675,404 | 25.0% | 31.0% | 28.9% | Iowa |
| N.Central | Michigan | 103.89% | 112,690,037 | 104,818,191 | 3,785,439 | 108,166,078 | 3.5% | 3.6% | 3.4% | Michigan |
| N.Central | Minnesota | 82.84% | 73,094,474 | 67,988,535 | 9,453,871 | 52,193,624 | 18.1% | 13.9% | 12.9% | Minnesota |
| N.Central | Missouri | 99.47% | 88,626,254 | 82,435,359 | 1,298,579 | 91,804,321 | 1.4% | 1.6% | 1.5% | Missouri |
| N.Central | North Dakota | 259.49% | 15,822,199 | 14,716,956 | 5,280,052 | 36,125,159 | 14.6% | 35.9% | 33.4% | North Dakota |
| N.Central | South Dakota | 82.32% | 12,615,449 | 11,734,210 | 2,914,666 | 12,034,206 | 24.2% | 24.8% | 23.1% | South Dakota |
| N.Central | Wisconsin | 83.97% | 73,988,479 | 68,820,090 | 3,233,178 | 53,742,910 | 6.0% | 4.7% | 4.4% | Wisconsin |
| NE | Connecticut | 106.16% | 31,707,213 | 29,492,338 | 666,525 | 36,117,544 | 1.8% | 2.3% | 2.1% | Connecticut |
| NE | Maine | 132.52% | 12,429,295 | 11,561,059 | 4,098,795 | 14,428,596 | 28.4% | 35.5% | 33.0% | Maine |
| NE | Massachusetts | 74.77% | 59,467,355 | 55,313,324 | 1,843,419 | 36,198,121 | 5.1% | 3.3% | 3.1% | Massachusetts |
| NE | New Hampshire | 194.97% | 11,686,618 | 10,870,261 | 1,381,285 | 19,264,435 | 7.2% | 12.7% | 11.8% | New Hampshire |
| NE | New York | 93.05% | 153,914,184 | 143,162,668 | 5,192,427 | 135,768,251 | 3.8% | 3.6% | 3.4% | New York |
| NE | Rhode Island | 97.63% | 8,287,230 | 7,708,334 | 101,895 | 8,309,036 | 1.2% | 1.3% | 1.2% | Rhode Island |
| S.Central | Arkansas | 113.99% | 50,378,720 | 46,859,567 | 1,660,370 | 65,005,678 | 2.6% | 3.5% | 3.3% | Arkansas |
| S.Central | Kansas | 110.28% | 43,319,516 | 40,293,476 | 5,252,653 | 44,424,691 | 11.8% | 13.0% | 12.1% | Kansas |
| S.Central | Louisiana | 90.08% | 91,094,022 | 84,730,743 | 2,430,042 | 103,407,706 | 2.3% | 2.9% | 2.7% | Louisiana |
| S.Central | Nebraska | 113.44% | 33,143,117 | 30,827,939 | 1,346,762 | 34,217,293 | 3.9% | 4.4% | 4.1% | Nebraska |
| S.Central | Oklahoma | 114.44% | 63,797,105 | 59,340,624 | 8,520,724 | 77,896,588 | 10.9% | 14.4% | 13.4% | Oklahoma |
| S.Central | Texas | 98.12% | 392,523,451 | 365,104,131 | 34,016,697 | 429,812,510 | 7.9% | 9.3% | 8.7% | Texas |
| SE | Alabama | 150.63% | 92,654,857 | 86,182,548 | 2,776,554 | 152,878,688 | 1.8% | 3.2% | 3.0% | Alabama |
| SE | Florida | 90.20% | 237,246,975 | 220,674,333 | 4,523,798 | 221,096,136 | 2.0% | 2.0% | 1.9% | Florida |
| SE | Georgia | 87.75% | 140,815,385 | 130,978,872 | 3,278,536 | 122,306,364 | 2.7% | 2.5% | 2.3% | Georgia |
| SE | Kentucky | 97.18% | 95,736,032 | 89,048,490 | 332,879 | 89,949,689 | 0.4% | 0.4% | 0.3% | Kentucky |
| SE | Mississippi | 98.63% | 52,021,589 | 48,387,675 | 1,509,190 | 54,584,295 | 2.8% | 3.1% | 2.9% | Mississippi |
| SE | North Carolina | 86.12% | 137,704,068 | 128,084,893 | 2,703,919 | 116,681,763 | 2.3% | 2.1% | 2.0% | North Carolina |
| SE | South Carolina | 115.08% | 83,622,303 | 77,780,953 | 2,143,473 | 96,755,682 | 2.2% | 2.8% | 2.6% | South Carolina |
| SE | Tennessee | 71.81% | 103,619,721 | 96,381,472 | 836,458 | 77,724,264 | 1.1% | 0.9% | 0.8% | Tennessee |
| Alaska | Alaska | 95.58% | 6,898,283 | 6,416,411 | 39,958 | 6,946,419 | 0.6% | 0.6% | 0.6% | Alaska |
| Hawaii | Hawaii | 96.24% | 10,363,058 | 9,639,157 | 924,815 | 10,469,269 | 8.8% | 9.6% | 8.9% | Hawaii |
| | | | | | | | | | | |
| West | Arizona | 142.51% | 80,700,600 | 75,063,343 | 1,697,652 | 95,016,925 | 1.8% | 2.3% | 2.1% | Arizona |
| West | California | 71.07% | 279,029,345 | 259,538,038 | 29,966,846 | 199,518,567 | 15.0% | 11.5% | 10.7% | California |
| West | Colorado | 89.08% | 57,717,063 | 53,685,297 | 6,192,082 | 52,556,701 | 11.8% | 11.5% | 10.7% | Colorado |
| West | Idaho | 46.83% | 25,492,620 | 23,711,859 | 2,514,502 | 15,499,089 | 16.2% | 10.6% | 9.9% | Idaho |
| West | Montana | 207.68% | 14,904,523 | 13,863,383 | 1,261,752 | 27,804,784 | 4.5% | 9.1% | 8.5% | Montana |
| West | Nevada | 96.67% | 37,821,930 | 35,179,918 | 2,968,630 | 35,173,263 | 8.4% | 8.4% | 7.8% | Nevada |
| West | New Mexico | 150.06% | 24,919,278 | 23,178,568 | 2,573,851 | 22,894,524 | 11.2% | 11.1% | 10.3% | New Mexico |
| West | Oregon | 111.21% | 50,195,189 | 46,688,856 | 7,207,229 | 60,932,715 | 11.8% | 15.4% | 14.4% | Oregon |
| West | Utah | 127.29% | 31,955,593 | 29,723,368 | 1,099,724 | 36,312,527 | 3.0% | 3.7% | 3.4% | Utah |
| West | Washington | 107.69% | 99,270,908 | 92,336,441 | 8,214,350 | 116,835,474 | 7.0% | 8.9% | 8.3% | Washington |
| West | Wyoming | 256.15% | 18,245,903 | 16,971,354 | 4,369,107 | 49,588,606 | 8.8% | 25.7% | 23.9% | Wyoming |

## Appendix D

## Implementation Related

**Review of Existing Air Permits for NGCC and Coal Generation Facilities**

| | | |
|---|---|---|
| Number of States Reviewed = | 43 | |
| Number of Air Permits Revived = | 302 | [185 coal; 119 NGCC; (2 with both coal & cc)] |
| Permits with Heat Rate Limits = | 0 | |
| Permits with Minimum Cap Factor Limit = | 0 | |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| AK | Healy | Coal | AQ0173TVP02 | 02/03/12 | none | none |
| AR | Flint Creek | Coal | 0276-AOP-R2 | 12/29/05 | none | none |
| AR | John W Turk Jr Power Plant | Coal | 2123-AOP-R0 | 11/05/08 | none | none |
| AR | Plum Point Energy Station | Coal | 1995-AOP-R2 | 01/11/08 | none | none |
| AZ | Springerville | Coal | 32008 | 07/21/06 | none | none |
| CO | Cherokee | Coal | 96OPAD130 | 02/10/14 | none | none |
| CO | Craig | Coal | 96OPMF155 | 05/01/05 | none | none |
| CO | Hayden | Coal | 96OPR0132 | 12/04/12 | none | none |
| CO | Nucla | Coal | 96OPMO168 | 09/25/07 | none | none |
| CO | Valmont | Coal | 96OPBO131 | 11/20/12 | none | none |
| CT | Bridgeport Station | Coal | 015-0217-TV | 10/31/12 | none | none |
| DE | Indian River Generating Station | Coal | AQM-005/00001 | 08/09/02 | none | none |
| FL | Big Bend | Coal | 0570039-045-AV | 03/28/11 | none | none |
| FL | Cedar Bay Generating Company LP | Coal | 0310337-017-AV | 05/25/14 | none | none |
| FL | Crist | Coal | 0330045-031-AV | 10/26/10 | none | none |
| GA | Hammond | Coal | 4911-115-0003-V03 | 05/08/12 | none | none |
| GA | Harllee Branch | Coal | 4911-237-0008-V03 | 03/09/12 | none | none |
| HI | AES Hawaii | Coal | 0087-01-C | 02/18/98 | none | none |
| IA | Ames Electric Services Power Plant | Coal | 97-TV-008R2 | 2013 | none | none |
| IA | Burlington | Coal | 98-TV-023R2 | 2012 | none | none |
| IA | Dubuque | Coal | 98-TV-007R2 | 2012 | none | none |
| IA | George Neal North | Coal | 97-TV-002R2 | 2013 | none | none |
| IA | George Neal South | Coal | 97-TV-003R2 | 05/20/13 | none | none |
| IA | Lansing | Coal | 98-TV-016R1 | 2006 | none | none |
| IA | Louisa | Coal | 98-TV-029R2 | 2013 | none | none |
| IA | Milton L Kapp | Coal | 98-TV-008R2 | 2008 | none | none |
| IA | Ottumwa | Coal | 98-TV-009R1 | 2005 | none | none |
| IA | Prairie Creek | Coal | 99TV-010R1 | 05/04/12 | none | none |
| IA | Riverside | Coal | 98--TV-004R2 | 2013 | none | none |
| IA | Walter Scott Jr Energy Center | Coal | 01-TV-0007R1 | 09/17/08 | none | none |
| IL | Dallman | Coal | 167120AAO | 08/10/06 | none | none |
| IL | Prairie State Generatng Station | Coal | 189808AAB | 04/28/05 | none | none |
| IN | A B Brown | Coal | 129-33047-00010 | 11/07/14 | none | none |
| IN | AES Petersburg | Coal | 125-30045-00002 | 07/18/13 | none | none |
| IN | Bailly | Coal | 127-29738-00002 | 09/06/12 | none | none |
| IN | Cayuga | Coal | 165-33876-00001 | 05/08/14 | none | none |
| IN | Clifty Creek | Coal | 077-29920-00001 | 07/07/11 | none | none |
| IN | Eagle Valley | Coal | 109-32791-00004 | 12/26/13 | none | none |
| IN | Edwardsport | Coal | 083-27138-00003 | 04/03/13 | none | none |
| IN | F B Culley | Coal | 173-29370-00001 | 03/11/11 | none | none |
| IN | Frank E Ratts | Coal | 125-34005-00001 | 07/15/14 | none | none |
| IN | Gibson | Coal | 051-34614-00013 | 10/07/14 | none | none |
| IN | Harding Street | Coal | 097-34265-00033 | 05/12/14 | none | none |
| IN | Logansport | Coal | 017-32817-00006 | 10/07/14 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| IN | Merom | Coal | 153-30525-00005 | 04/24/14 | none | none |
| IN | Michigan City | Coal | 091-29806-00021 | 09/22/14 | none | none |
| IN | R Gallagher | Coal | 043-27078-00004 | 09/28/10 | none | none |
| IN | R M Schahfer | Coal | 073-29983-00008 | 12/28/12 | none | none |
| IN | Rockport | Coal | 147-29841-00020 | 08/15/14 | none | none |
| IN | State Line Energy | Coal | 089-31643-00210 | 06/21/12 | none | none |
| IN | Tanners Creek | Coal | 029-34394-00002 | 08/12/14 | none | none |
| IN | Wabash River | Coal | 167-33215-00021 | 03/13/14 | none | none |
| KY | Big Sandy | Coal | V-06-053 | 07/02/07 | none | none |
| KY | H L Spurlock | Coal | V-06-007 | 07/31/06 | none | none |
| KY | Trimble County | Coal | V-02-043R3 | 02/29/08 | none | none |
| MA | Brayton Point | Coal | W051616 | 07/25/11 | none | none |
| MA | Mount Tom | Coal | 1-O-95-028 | 11/02/06 | none | none |
| MA | Salem Harbor | Coal | X236090 | 01/13/11 | none | none |
| MI | B C Cobb | Coal | B2836-2011 | 08/09/11 | none | none |
| MI | Belle River | Coal | B2796-2009A | 07/01/09 | none | none |
| MI | Dan E Karn | Coal | B2840-2014 | 11/12/14 | none | none |
| MI | Eckert Station | Coal | B2647-2012b | 05/17/12 | none | none |
| MI | Erickson Station | Coal | B4001-2012 | 09/07/10 | none | none |
| MI | Greenwood | Coal | B6145-2011a | 10/01/11 | none | none |
| MI | Harbor Beach | Coal | B2815-2012 | 01/11/12 | none | none |
| MI | J B Sims | Coal | B1976-2011 | 12/01/11 | none | none |
| MI | J H Campbell | Coal | B2835-203 | 09/18/13 | none | none |
| MI | J R Whiting | Coal | B2846-2013 | 09/01/13 | none | none |
| MN | Allen S King | Coal | 16300005-012 | 06/20/13 | none | none |
| MN | Sherburne County | Coal | 11400004-004 | 01/29/13 | none | none |
| MO | Iatan | Coal | 012006-019 | 01/31/06 | none | none |
| MS | Red Hills Generating Facility | Coal | 400-00011 | 07/27/99 | none | none |
| MT | Hardin Generator Project | Coal | 3185-05 | 07/16/09 | none | none |
| NC | Belews Creek | Coal | 01983T28 | 04/01/13 | none | none |
| NC | Cliffside | Coal | 04044T28 | 01/29/08 | none | none |
| NC | Edgecombe Genco LLC | Coal | 06563T15 | 03/05/14 | none | none |
| NC | G G Allen | Coal | 03757T39 | 04/07/14 | none | none |
| NC | HF Lee Plant | Coal | 01812T39 | 06/18/13 | none | none |
| NC | L V Sutton Steam | Coal | 01318T30 | 07/16/14 | none | none |
| NC | Mayo | Coal | 03478T40 | 10/29/14 | none | none |
| NC | Roxboro | Coal | 05856T15 | 11/25/13 | none | none |
| ND | Antelope Valley | Coal | T5F86003 | 06/06/14 | none | none |
| ND | Coal Creek | Coal | T5F82006 | 10/21/14 | none | none |
| ND | Coyote | Coal | T5F84011 | 08/15/13 | none | none |
| ND | Leland Olds | Coal | T5F73004 | 03/27/14 | none | none |
| ND | Milton R Young | Coal | T5F76009 | 05/13/10 | none | none |
| ND | R M Heskett | Coal | T5F76001 | 04/27/10 | none | none |
| ND | Spiritwood Station | Coal | T4F10001 | 07/08/10 | none | none |
| ND | Stanton | Coal | T5F76007 | 01/08/10 | none | none |
| NE | Nebraska City | Coal | 58343 | 03/06/08 | none | none |
| NE | Whelan Energy Center | Coal | 58048c02 | 03/30/04 | none | none |
| NV | TS Power Plant | Coal | 4911-1349 | 09/17/17 | none | none |
| NY | C R Huntley Generating Station | Coal | 9-1464-00130 | 01/30/09 | none | none |
| NY | Cayuga Operating Company | Coal | 7-5032-00019 | 10/15/08 | none | none |
| NY | Danskammer Generating Station | Coal | 3-3346-00011 | 03/11/13 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| NY | Dunkirk Generating Plant | Coal | 9-0603-00021 | 01/30/09 | none | none |
| NY | Somerset Operating Co LLC | Coal | 9-2938-00003 | 04/26/11 | none | none |
| OH | Avon Lake | Coal | P0085252 | 06/20/03 | none | none |
| OH | Cardinal | Coal | P0089699 | 12/31/02 | none | none |
| OH | Conesville | Coal | P0089101 | 02/12/98 | none | none |
| OH | FirstEnergy Ashtabula | Coal | P0084050 | 12/23/02 | none | none |
| OH | FirstEnergy Bay Shore | Coal | P0085252 | 04/04/07 | none | none |
| OH | FirstEnergy Eastlake | Coal | P0085103 | 12/27/02 | none | none |
| OH | FirstEnergy Lake Shore | Coal | P0094243 | 06/20/03 | none | none |
| OH | FirstEnergy R E Burger | Coal | P0089083 | 12/26/02 | none | none |
| OH | FirstEnergy W H Sammis | Coal | P0089748 | 12/24/02 | none | none |
| OH | General James M Gavin | Coal | P0089257 | 01/30/02 | none | none |
| OH | Hamilton | Coal | P0097012 | 11/14/13 | none | none |
| OH | J M Stuart | Coal | P0091206 | 05/16/01 | none | none |
| OH | Killen Station | Coal | P0091217 | 06/20/13 | none | none |
| OH | Kyger Creek | Coal | P0089198 | 02/12/98 | none | none |
| OH | Miami Fort | Coal | P0099745 | 08/21/03 | none | none |
| OH | Muskingum River | Coal | P0090944 | 01/30/02 | none | none |
| OH | Niles | Coal | P0086141 | 06/28/13 | none | none |
| OH | O H Hutchings | Coal | P0093904 | 01/13/03 | none | none |
| OH | Orrville | Coal | P0107692 | 06/02/14 | none | none |
| OH | Picway | Coal | P0083809 | 02/27/02 | none | none |
| OH | W H Zimmer | Coal | P0097734 | 11/18/04 | none | none |
| OH | Walter C Beckjord | Coal | P0097735 | 06/20/03 | none | none |
| OR | Boardman | Coal | 25-0016-TV-01 | 12/08/10 | none | none |
| PA | Seward | Coal | PA-32-040B | 2003 | none | none |
| SC | Cross | Coal | 0420-0030-CI | 02/05/04 | none | none |
| SD | Ben French | Coal | 28.0801-02 | 04/08/14 | none | none |
| SD | Big Stone | Coal | 28.0801-29 | 06/09/09 | none | none |
| TX | AES Deepwater | Coal | O95 | 12/07/05 | none | none |
| TX | J K Spruce | Coal | 70492 | 11/01/07 | none | none |
| TX | Oklaunion | Coal | O38 | 09/21/06 | none | none |
| TX | Sandy Creek Energy Station | Coal | 70861 | 05/05/11 | none | none |
| TX | Welsh | Coal | 4381 | 03/20/07 | none | none |
| UT | Carbon | Coal | 700002004 | 12/10/12 | none | none |
| UT | Huntington | Coal | 1501001003 | 08/19/10 | none | none |
| UT | Intermountain Power Project | Coal | AN0327010-04 | 10/15/04 | none | none |
| UT | Sunnyside Cogen Associates | Coal | 700030003 | 06/26/13 | none | none |
| VA | Altavista Power Station | Coal | 30859 | 1/15/2013 | none | none |
| VA | Birchwood Power | Coal | 40809 | 04/22/05 | none | none |
| VA | Bremo Bluff | Coal | 40199 | 01/01/14 | none | none |
| VA | Chesapeake | Coal | 60163 | 12/27/07 | none | none |
| VA | Chesterfield | Coal | 50396 | 10/18/05 | none | none |
| VA | Clinch River | Coal | 10236 | 01/01/10 | none | none |
| VA | Clover | Coal | 30867 | 10/28/02 | none | none |
| VA | Glen Lyn | Coal | 20460 | 01/16/03 | none | none |
| VA | Hopewell Power Station | Coal | 51019 | 03/21/13 | none | none |
| VA | James River Genco LLC | Coal | 50950 | 05/08/01 | none | none |
| VA | Mecklenburg Power Station | Coal | 30861 | 12/27/06 | none | none |
| VA | Portsmouth Genco LLC | Coal | 61049 | 04/01/12 | none | none |
| VA | Potomac River | Coal | 11526 | 06/30/08 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| VA | Southampton Power Station | Coal | 61093 | 08/29/13 | none | none |
| VA | Spruance Genco LLC | Coal | 51033 | 06/04/01 | none | none |
| VA | Virginia City Hybrid Energy Center | Coal | 7/22/1931 | 06/25/08 | none | none |
| VA | Yorktown | Coal | 60137 | 12/27/07 | none | none |
| WI | Columbia | Coal | 111003090-P28 | 09/25/14 | none | none |
| WI | Edgewater | Coal | 460033090-P22 | 03/12/13 | none | none |
| WI | Elm Road Generating Station | Coal | 241007690-P20 | 09/11/14 | none | none |
| WI | Genoa | Coal | 663020930-P20 | 01/23/09 | none | none |
| WI | Manitowoc | Coal | 436035930-P22 | 07/23/13 | none | none |
| WI | Nelson Dewey Coal Refining Facility | Coal | 122014530-P11 | 10/20/08 | none | none |
| WI | Pleasant Prairie | Coal | 230006260-P10 | 12/08/10 | none | none |
| WI | Weston | Coal | 03-RV-248 | 10/19/04 | none | none |
| WV | FirstEnergy Albright | Coal | 077-00001 | 06/03/14 | none | none |
| WV | FirstEnergy Fort Martin Power Station | Coal | 061-00001 | 06/23/09 | none | none |
| WV | FirstEnergy Harrison Power Station | Coal | 033-00015 | | none | none |
| WV | FirstEnergy Pleasants Power Station | Coal | 073-00005 | | none | none |
| WV | FirstEnergy Willow Island | Coal | 079-00004 | | none | none |
| WV | Grant Town Power Plant | Coal | 049-00026 | | none | none |
| WV | John E Amos | Coal | 079-00006 | | none | none |
| WV | Kammer | Coal | 051-00006 | | none | none |
| WV | Kanawha River | Coal | 039-00006 | | none | none |
| WV | Longview Power LLC | Coal | 061-00134 | 05/14/13 | none | none |
| WV | Mitchell | Coal | 051-00005 | 10/15/14 | none | none |
| WV | Morgantown Energy Facility | Coal | 061-00027 | 12/09/08 | none | none |
| WV | Mountaineer | Coal | 053-00009 | | none | none |
| WV | Mt Storm | Coal | 023-00003 | | none | none |
| WV | Philip Sporn | Coal | 053-00001 | | none | none |
| WY | Dave Johnston | Coal | 3-2-148 | 09/02/08 | none | none |
| WY | Dry Fork Station | Coal | CT-4631 | 10/15/07 | none | none |
| WY | Jim Bridger | Coal | 3-1-120-2 | 09/06/05 | none | none |
| WY | Laramie River Station | Coal | 3-2-102 | 06/24/09 | none | none |
| WY | Naughton | Coal | 3-2-121 | 03/19/08 | none | none |
| WY | Neil Simpson II | Coal | 3-2-158-1 | 10/29/13 | none | none |
| WY | Wygen 1 | Coal | 3-0-205 | 08/11/05 | none | none |
| WY | Wygen 2 | Coal | 3-0-229 | 06/07/11 | none | none |
| WY | Wygen III | Coal | CT-4517 | 02/05/07 | none | none |
| WY | Wyodak | Coal | 3-2-101-1 | 09/05/13 | none | none |
| FL | C D McIntosh Jr | Coal/CC | 1050004-020-AV | 03/28/11 | none | none |
| MN | Black Dog | Coal/CC | 03700003-011 | | none | none |
| AK | Beluga | NGCC | AQ0106TVP03 | 09/11/14 | none | none |
| AK | George M Sullivan Generation Plant 2 | NGCC | AQ0203CPT02 | 06/06/13 | none | none |
| AK | Nikiski Co-Generation | NGCC | AQ1190TVP01 | 09/30/09 | none | none |
| AR | Harry L. Oswald | NGCC | 1842-AOP-R5 | 03/15/10 | none | none |
| AR | Thomas Fitzhugh | NGCC | 1165-AOP-R5 | 09/30/13 | none | none |
| CA | Delta Energy Center | NGCC | B2095 | 09/15/13 | none | none |
| CA | Dynegy Moss Landing Power Plant | NGCC | TV45-02 | 09/04/09 | none | none |
| CA | Gateway Generating Station | NGCC | B8143 | 01/28/14 | none | none |
| CA | High Desert Power Plant | NGCC | 104701849 | 09/18/11 | none | none |
| CA | Los Medanos Energy Center | NGCC | B1866 | 07/15/13 | none | none |
| CA | Metcalf Energy Center | NGCC | B2183 | 07/08/11 | none | none |
| CO | Arapahoe Combustion Turbine Project | NGCC | 01OPDE237 | 09/24/08 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| CO | Brush Generation Facility | NGCC | 96OPMR153 | 10/05/11 | none | none |
| CO | Fort St Vrain | NGCC | 97OPWE180 | 09/09/11 | none | none |
| CO | Rifle Generating Station | NGCC | 95OPGA028 | 08/01/10 | none | none |
| CO | Rocky Mountain Energy Center | NGCC | 05OPWE279 | 08/08/12 | none | none |
| CO | Thermo Power & Electric | cNGCC | 95OPWE001 | 01/01/11 | none | none |
| CT | Algonquin Windsor Locks | cNGCC | 213-0069TV | 02/18/10 | none | none |
| CT | Bridgeport Energy Project | NGCC | 015-0256-TV | 09/11/12 | none | none |
| CT | Capital District Energy Center | cNGCC | 075-0244-TV | 03/13/14 | none | none |
| CT | Kleen Energy Systems Project | NGCC | 104-0150-TV | 11/16/12 | none | none |
| CT | Lake Road Generating Plant | NGCC | 089-0083-TV | 11/15/11 | none | none |
| CT | Milford Power Project | NGCC | 105-0071-TV | 09/11/14 | none | none |
| FL | Arvah B Hopkins | NGCC | 0730003-014-AV | 01/01/13 | none | none |
| FL | Brandy Branch | NGCC | 0310485-022-AV | 01/01/14 | none | none |
| FL | Cane Island | NGCC | 0970043-021-AV | 01/14/14 | none | none |
| GA | Chattahoochee Energy Facility | NGCC | 4911-149-0006-V04 | 07/31/12 | none | none |
| GA | Effingham County Power Project | NGCC | 4911-103-0012-V04 | 05/30/12 | none | none |
| IA | Emery Station | NGCC | 07-TV-011R1 | 04/11/13 | none | none |
| IA | Summit Lake | NGCC | 99-TV-003R2 | 08/02/12 | none | none |
| ID | Rathdrum Power LLC | NGCC | T1-2009.0111 | 02/12/10 | none | none |
| IL | Kendall County Generation Facility | NGCC | 093808AAD | 03/20/09 | none | none |
| IN | Lawrenceburg Energy Facility | NGCC | 029-31176-00033 | 05/04/11 | none | none |
| IN | Noblesville | NGCC | 057-33088-00004 | 08/05/13 | none | none |
| IN | Portside Energy | cNGCC | 127-32113-00067 | 11/06/12 | none | none |
| IN | Sugar Creek Power | NGCC | 167-33864-00123 | 05/15/14 | none | none |
| IN | Whiting Clean Energy | NGCC | 089-29885-00449 | 08/19/11 | none | none |
| LA | Coughlin Power Station | NGCC | 0920-00002-V4 | 09/22/14 | none | none |
| LA | J Lamar Stall Unit | NGCC | PSD-LA-726 | 06/07/10 | none | none |
| LA | Louisiana 1 | NGCC | 0840-00181-V3 | 12/16/13 | none | none |
| LA | Perryville Power Station | NGCC | 2160-00112-V3 | 09/14/12 | none | none |
| LA | Sterlington | NGCC | 2160-00004-V1 | 02/22/12 | none | none |
| MA | ANP Bellingham Energy Project | NGCC | W039085 | 10/28/05 | none | none |
| MA | ANP Blackstone Energy Project | NGCC | W027087 | 10/07/05 | none | none |
| MA | Bellingham Cogeneration Facility | cNGCC | 79300 | 04/04/14 | none | none |
| MA | Berkshire Power | NGCC | X262374 | 07/22/14 | none | none |
| MA | Cleary Flood | NGCC | X224279 | 06/03/10 | none | none |
| MA | Dighton Power Plant | NGCC | X233189 | 08/20/09 | none | none |
| MA | Fore River Generating Station | NGCC | W049142 | 04/19/16 | none | none |
| MA | Kendall Square Station | NGCC | X259667 | 01/07/13 | none | none |
| MA | Masspower | NGCC | W04998 | 09/01/05 | none | none |
| MA | Milford Power LP | NGCC | X259207 | 04/03/14 | none | none |
| MA | Millennium Power | NGCC | W065466 | 03/24/05 | none | none |
| MA | Mystic Generating Station | NGCC | X238907 | 08/10/11 | none | none |
| MA | Pittsfield Generating LP | NGCC | W048856 | 04/19/06 | none | none |
| MA | Stony Brook | NGCC | X232364 | 01/28/13 | none | none |
| ME | Maine Independence Station | NGCC | A-728-70-C-R | 01/06/10 | none | none |
| ME | Rumford Power Associates | NGCC | A-724-70-D-R/A | 02/19/09 | none | none |
| ME | Westbrook Energy Center Power Plant | NGCC | A-743-70-A-I | 11/03/10 | none | none |
| MI | Dearborn Industrial Generation | NGCC | N6631-2012 | 03/28/12 | none | none |
| MI | Midland Cogeneration Venture | NGCC | B6527-2014 | 09/30/14 | none | none |
| MI | New Covert Generating Facility | NGCC | N6767-2014 | 10/24/14 | none | none |
| MN | Faribault Energy Park | NGCC | 13100071-003 | 05/09/11 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| MN | High Bridge | NGCC | 12300012-005 | 01/11/06 | none | none |
| MN | LSP-Cottage Grove LP | NGCC | 16300087-006 | 06/06/13 | none | none |
| MN | Mankato Energy Center | NGCC | 01300098-002 | 02/14/14 | none | none |
| MN | Riverside | NGCC | 05300015-005 | 12/02/08 | none | none |
| NC | Butler-Warner Generation Plant | NGCC | 03029T17 | 11/09/12 | none | none |
| NC | Rosemary Power Station | NGCC | 06586T16 | 04/07/11 | none | none |
| NC | Rowan | NGCC | 08758T16 | 04/08/14 | none | none |
| NH | EP Newington Energy LLC | NGCC | TP-0150 | 08/21/14 | none | none |
| NH | Granite Ridge | NGCC | TV-OP-056 | 11/17/08 | none | none |
| NV | Chuck Lenzie Generating Station | NGCC | 1513 | 10/20/09 | none | none |
| NV | Silverhawk | NGCC | 1584 | 05/30/06 | none | none |
| NY | Astoria Energy II | NGCC | 2-6301-00072 | 10/04/13 | none | none |
| NY | Athens Generating Plant | NGCC | 4-1922-00055 | 01/24/07 | none | none |
| NY | Batavia Power Plant | NGCC | 8-1802-00045 | 08/13/07 | none | none |
| NY | Bethlehem Energy Center | NGCC | 4-0122-00044 | 12/05/13 | none | none |
| NY | Caithness Long Island Energy Center | NGCC | 1-4722-04426 | 01/12/12 | none | none |
| NY | E F Barrett | NGCC | 1-2820-00553 | 03/27/12 | none | none |
| NY | East River | NGCC | 2-6206-00012 | 05/12/09 | none | none |
| NY | Indeck Corinth Energy Center | cNGCC | 5-4126-00028 | 01/15/14 | none | none |
| NY | Indeck Olean Energy Center | cNGCC | 9-0412-00042 | 09/12/07 | none | none |
| NY | Indeck Oswego Energy Center | cNGCC | 7-3512-00005 | 12/04/00 | none | none |
| NY | Indeck Silver Springs Energy Center | NGCC | 9/5632-00010 | 07/02/12 | none | none |
| NY | Indeck Yerkes Energy Center | NGCC | 9-1464-00153 | 01/10/07 | none | none |
| NY | Massena Energy Facility | NGCC | 6-4058-00046 | 06/29/11 | none | none |
| NY | Pinelawn Power LLC | NGCC | 1-4720-03061 | 02/08/10 | none | none |
| NY | Ravenswood | NGCC | 2-6304-00024 | 02/04/10 | none | none |
| NY | Rensselaer Cogen | cNGCC | 4-3814-00029 | 04/19/11 | none | none |
| NY | Richard M Flynn | NGCC | 1-4722-00926 | 02/08/11 | none | none |
| NY | Saranac Facility | cNGCC | 5-0942-00106 | 07/18/12 | none | none |
| NY | Selkirk Cogen | cNGCC | 4-0122-00078 | 11/04/14 | none | none |
| OH | AEP Waterford Facility | NGCC | P0091005 | 05/20/14 | none | none |
| OH | Dresden Energy Facility | NGCC | P0112692 | 10/21/14 | none | none |
| OH | Fremont Energy Center | NGCC | P0109022 | 04/27/12 | none | none |
| OH | Hanging Rock Energy Facility | NGCC | P0110486 | 03/07/13 | none | none |
| OH | Washington Energy Facility | NGCC | P0105635 | 04/03/14 | none | none |
| OK | Comanche | NGCC | 2003-261-TVR | 04/22/06 | none | none |
| OK | Northeastern | NGCC | 2033-410-TVR2 | 08/24/10 | none | none |
| OR | Beaver | NGCC | 05-2520 | 05/23/08 | none | none |
| OR | Coyote Springs | NGCC | 25-0031-TV-01 | 05/31/13 | none | none |
| RI | Manchester Street | NGCC | RI-22-07 | 07/31/09 | none | none |
| RI | Ocean State Power | NGCC | RI-15-12 | 04/13/01 | none | none |
| RI | Pawtucket Power Associates | NGCC | RI-18-12 | 12/20/12 | none | none |
| UT | Nebo Power Station | NGCC | 4900234002 | 11/16/11 | none | none |
| VA | Bear Garden | NGCC | 32004 | 01/01/14 | none | none |
| VA | Bellmeade Power Station | NGCC | 50988 | 01/01/14 | none | none |
| VA | Doswell Energy Center | NGCC | 51018 | 09/17/14 | none | none |
| VA | Gordonsville Energy LP | NGCC | FSO40808 | 09/05/03 | none | none |
| VA | Hopewell Cogeneration | NGCC | 50967 | 12/01/03 | none | none |
| VA | Possum Point | NGCC | 70225 | 01/01/03 | none | none |
| VA | Tenaska Virginia Generating Station | NGCC | 40955 | 01/01/13 | none | none |
| WA | Goldendale Generating Station | NGCC | 11AQ-C167 | 08/07/14 | none | none |

| State | Plant | Unit Type | Permit # | Permit Date | Heat Rate Limit | Mininum Capacity Factor Permit Condition |
|---|---|---|---|---|---|---|
| WA | Sumas Power Plant | NGCC | 637-V-W | 01/11/11 | none | none |
| WI | Fox Energy Center | NGCC | 445159110-P01 | 09/19/02 | none | none |
| WI | Port Washington Generating Station | NGCC | 246004000-P10 | 10/01/09 | none | none |

**Proposed Clean Power Plan for Existing Power Plants**

**Listing of U.S. Environmental Protection Agency Requests for Comment***

Vol. 79, Federal Register, No. 117, Wednesday, June 18, 2014
Environmental Protection Agency
40 CFR Part 60
Carbon Pollution Emission Guidelines for Existing Stationary Sources:
Electric Utility Generating Units; Proposed Rule

*Please note: comments must be received on or before October 16, 2014.

| **Category** | **Comment** | **Page No. in *Federal Register*** |
|---|---|---|
| General | The EPA is offering the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data used in the computations. | **34835** |
| General | The EPA invites further input through public comment on all aspects of this proposal. | **34835** |
| Compliance Time | The agency is also requesting comment on an alternative option, a 5-year period for compliance, in combination with a less stringent set of $CO_2$ emission performance levels. | **34839** |
| Building Blocks | The EPA is also seeking comment on different combinations of building blocks and different levels of stringency for each building block. | **34839** |
| Stakeholder Proposals | During the EPA's public outreach in advance of this proposal, a number of ideas were put forward that are not fully reflected in this proposal. We invite public comment on these ideas, some of which are outlined below. | **34847** |
| Stakeholder Proposals | Other stakeholders suggested that an ''inside the fence'' plant- or unit-specific assessment linked to the availability of control at the source such as heat rate improvements should be considered. They indicated that once plant-specific goals are established based on on-site $CO_2$ reduction opportunities, the source should have the flexibility to look ''outside the fence'' for the means to achieve the goals, including the use of emissions trading and averaging. The EPA invites comment on these suggestions. | **34848** |
| Legal Interpretation | The EPA discusses its legal interpretation in more detail in other parts of this preamble and discusses certain issues in more detail in the Legal Memorandum included in the docket for this rulemaking. The EPA solicits comment on all aspects of its legal interpretations, including the discussion in the Legal Memorandum. | **34853** |

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| Tribal | The EPA invites comment on whether a tribe wishing to develop and implement a CAA section 111(d) plan should have the option of including the EGUs located in its area of Indian country in a multi-jurisdictional plan with one or more states (i.e., treating the tribal lands as an additional state). | **34854** |
| Tribal | If the EPA develops one or more CAA section 111(d) federal plans for areas of Indian country with affected EGUs, we are likewise currently considering doing so on a multi-jurisdictional basis in coordination with nearby states developing CAA section 111(d) plans. The EPA solicits comment on such an approach for a federal plan. | **34854** |
| Tribal | We invite comment on how the BSER should be applied to potentially affected EGUs in Indian country. | **34855** |
| Tribal | We particularly invite comment on data sources for setting renewable energy and demand-side energy efficiency targets. | **34855** |
| Tribal | The state-specific goals that the EPA is proposing are based on the collection of affected EGUs located within that state. In setting goals specific to an area of Indian country, the EPA proposes to base the goals on the collection of affected EGUs located within that area of Indian country. We request comment on this approach. | **34855** |
| Combining Categories | The EPA is soliciting comment on combining the two existing categories for the affected EGUs into a single category for purposes of facilitating emission trading among sources in both categories. | **34855** |
| Combining Categories | The EPA is proposing emission guidelines for the two categories and is soliciting comment on combining the two categories into a single category for purposes of the $CO_2$ emissions from existing affected EGUs. | **34855** |
| Combining Categories | The EPA solicits comment on whether combining the two categories would offer additional flexibility, for example, by facilitating implementation of $CO_2$ mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or facilitating emissions trading among sources. | **34855** |
| Building Blocks | We are proposing that the basis for supporting the BSER should include heat rate improvements only at coal-fired steam EGUs, but we are inviting comment on including heat rate improvements at other EGU types. | **34856** |
| Building Blocks | As noted later in this preamble, we are seeking comment on the extent to which existing EGUs could implement CCS in order to improve our understanding. | **34857** |
| Building Blocks | Gas conversion or co-firing would be available to states and sources as a compliance option, and, as noted later in the preamble, we are seeking comment on whether this option should be considered part of the BSER. | **34857** |
| Building Blocks | As noted in Section VI.C.5.d below, we are requesting comment on including heat rate improvement opportunities at other EGU types in the basis for supporting the BSER. | **34859** |
| Building Blocks | We believe a reasonable estimate for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a four percent improvement in heat rate through adoption of best practices to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation. We also solicit comment on the use of estimates up to six percent, reflecting elimination on average of 50 percent of the deviation from top-decile performance. | **34860** |

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| Building Blocks | We propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity remains—i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity is on average two percent rather than four percent. We solicit comment on increasing this figure up to four percent. | **34860** |
| Building Blocks | Based on the analyses of technical potential and cost summarized above, we propose to find that a six percent reduction in the $CO_2$ emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost. However, as discussed in Section VI.C.5.d below, we are requesting comment on this aspect of the proposal. Further, states and sources would be free to use heat rate improvements at those other units to help reach the state goals. | **34862** |
| Building Blocks | We invite comment on all aspects of our analyses and findings related to heat rate improvements, both as summarized here and as further discussed in the Greenhouse Gas Abatement Measures TSD. | **34862** |
| Building Blocks | As noted earlier, we specifically request comment on increasing the estimates of the amounts of heat rate improvement achievable through adoption of best practices for operation and maintenance and through equipment upgrades up to six percent and four percent, respectively, representing a total potential improvement of up to ten percent, particularly in light of the reasonable cost of heat rate improvements. | **34862** |
| Building Blocks | We also solicit comment on the quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads. | **34862** |
| Building Blocks | We invite comment on whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for $CO_2$ emission reductions, and in assessing costs. | **34865** |
| Building Blocks | We invite comment on whether we should consider options for a target utilization rate for existing NGCC units greater than the proposed 70 percent target utilization rate. | **34866** |
| Building Blocks | We invite comment on the findings regarding the potential for increased utilization of existing NGCC units to support the BSER and on all other issues raised by the discussion above and the related portions of the Greenhouse Gas Abatement Measures TSD. | **34866** |
| Building Blocks | We invite comment regarding the treatment of Alaska and Hawaii as part of this method for developing annual RE generation levels. | **34867** |
| Building Blocks | For some states, the RE generation targets developed using the proposed approach are less than the states' reported RE generation amounts for 2012. We invite comment on whether the approach for quantifying the RE generation component of each state's goal should be modified to include a floor based on reported 2012 RE generation in that state. | **34868** |
| Building Blocks | The EPA invites comment on whether the approach for quantifying the RE generation component of each state's goal should be modified so that the difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's reported 2012 fossil fuel-fired generation. | **34868-34869** |

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| Building Blocks | With regard to hydropower, we seek comment regarding whether to include 2012 hydropower generation from each state in that state's ''best practices'' RE quantified under the proposed approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER. Chapter 4 of the GHG Abatement Measures TSD presents state RE targets both with and without the inclusion of each state's 2012 hydropower generation. | **34869** |
| Building Blocks | We invite comment on the proposed approach to treatment of renewable generating capacity as a basis for the best system of emission reduction adequately demonstrated and for quantification of state goals. | **34869** |
| Building Blocks | We invite comment on the alternative approach to quantification of RE generation to support the BSER described on pages 34869-70. We note that the three specific requests for comment made above with respect to the proposed quantification approach— addressing, first, the possibility of a floor based on 2012 RE generation, second, the possibility of a limitation based on 2012 fossil fuel-fired generation and, third, the treatment of hydropower generation—apply to this alternative approach as well. | **34870** |
| Building Blocks | The EPA invites comment on other possible techno-economic approaches to quantification of RE generation to support the BSER. For example, a conceptual framework for another techno-economic approach is provided in the Alternative RE Approach TSD. | **34870** |
| Building Blocks | We request comment on whether it is appropriate to reflect completion of the five identified nuclear EGUs currently under construction in the state goals and on alternative ways of considering these units when setting state goals. | **34870** |
| Building Blocks | We invite comment on all aspects of the approach discussed for treatment of nuclear generation. In addition, we specifically request comment on whether we should include in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation. | **34871** |
| Building Blocks | As discussed in Section VII.E below, the EPA is also taking comment on a less stringent alternative for setting state goals. | **34873** |
| Building Blocks | We invite comment on all aspects of our data and methodology for estimating the potential for demand-side energy efficiency to support the BSER as discussed in the preamble and in the TSD, as well as on the level of reductions we propose to define as best practices suitable for representation consistent with the best system of emission reduction and the level reflected in the less stringent scenario. | **34875** |
| Building Blocks | For demand-side EE, we also specifically invite comment on several issues: (1) Increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards, (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state's current level of annual incremental electricity savings, and (3) alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side energy efficiency policies. | **34875** |

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| Building Blocks | We solicit comment on whether natural gas co-firing or conversion should be part of the BSER. | **34876** |
| Building Blocks | We also request comment regarding whether, and, if so, how, we should consider the co-benefits of natural gas co-firing in making the BSER determination. | **34876** |
| Building Blocks | The EPA does solicit comment on all aspects of applying CCS to existing fossil fuel-fired EGUs (in either full or partial configurations), but does not expect to finalize CCS as a component of the BSER in this rulemaking. | **34876** |
| Building Blocks | We invite comment on whether we should consider construction and use of new NGCC capacity as part of the basis supporting the BSER. | **34877** |
| Building Blocks | We request comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity. | **34877** |
| Building Blocks and U.S. territories | We invite comment on whether heat rate improvements for one or more types of non-coal fossil fuel-fired EGUs should be identified as a basis for supporting the BSER, with particular reference to U.S. territories. | **34877** |
| Building Blocks | We invite comment on a potential BSER comprising a combination of building blocks 1 and 2. | **34878** |
| Building Blocks | The EPA invites comment on a potential BSER comprising building blocks 1 and 2, in light of the considerations that could support this approach. | **34885** |
| Building Blocks | In recognition of stakeholders' expressed concerns, we invite comment on whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered. | **34887** |
| Building Blocks | We note that some stakeholders have argued that CAA section 111(a)(1) does not authorize the EPA to identify redispatch, low- or zero-emitting generation, or demand-side energy efficiency measures (building blocks 2, 3, and 4) as components of the ''best system of emission reduction . . .adequately demonstrated.'' According to these stakeholders, as a legal matter, the BSER is limited to measures that may be undertaken at the affected units, and not measures that are beyond the affected units; the measures in building blocks 2, 3, and 4 are ''beyond-the-unit'' or ''beyond-the-fenceline'' measures because they are implemented outside of the affected units and outside their control; and as a result, those measurescannot be considered components of the BSER. We welcome comment on this issue. | **34888** |
| Building Blocks | The EPA solicits comment on whether measures in addition to those in building blocks 2, 3, and 4 could support the showing that reduced utilization is ''adequately demonstrated,'' including additional NGCC capacity that may be built in the future, as discussed in Section VI.C.5.c above. | **34890** |
| Building Blocks | As discussed above, the EPA is soliciting comment on combining the category of steam EGUs and the category of combustion turbines (which include NGCC units) into a single category for fossil fuel-fired EGUs, for purposes of promulgating emission guidelines for $CO_2$ emissions. | **34892** |
| Building Blocks | The EPA solicits comment on whether combining the categories is, as a legal matter, a prerequisite for (i) identifying as a component of the BSER re-dispatch between sources in the two categories (i.e., re-dispatch between steam EGUs and NGCC units), or (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt. | **34892** |

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| Building Blocks | We invite comment on all aspects of our proposed interpretation and alternate interpretation of the BSER for $CO_2$ emissions from existing fossil fuel-fired EGUs, both as identified above and as further discussed in the Legal Memorandum in the docket. In particular, we invite comment on our analysis of the four building blocks as components of the BSER, whether any other potential measures should be considered, our analysis of the combinations of building blocks 1 and 2 and of all four building blocks, and the legal, technical, and economic bases of our conclusions. | **34892** |
| Building Blocks | Some commenters noted that trading programs like RGGI have been successful at reducing GHGs, and other commenters provided specific BSER proposals based on trading and/or emissions averaging approaches. We specifically request comment on whether any of these approaches should be considered as the BSER. | **34892** |
| Building Blocks | We also specifically invite comment on the question, raised by some stakeholders, as to whether if measures may be relied on in the state plan to achieve emission reductions, they cannot be excluded from the scope of the BSER solely because they involve actions by entities or at locations other than affected sources. | **34892** |
| State Goals | We are requesting comment on a second set of state-specific goals that would reflect less stringent application of the same BSER, in this case by 2025, with interim goals that would apply over a 2020–2024 phase-in period. | **34892** |
| State Goals | As noted in Section VI.C.5.d above, we are requesting comment on whether heat rate improvements for non-coal fossil fuel-fired EGUs should be part of the basis supporting the BSER, with particular reference to the situation of geographically isolated jurisdictions such as the U.S. territories. | **34893** |
| State Goals | A state's inability to meet the level of emission reductions anticipated through use of one building block may free up resources that the state could then devote to more stringent implementation of another building block. This approach would mean that overall, the same nationwide level of emission reductions as proposed would be achieved. The EPA invites comment on this aspect of the proposal. | **34893** |
| State Goals | With respect to U.S. territories, the EPA is currently aware of potentially affected EGUs in Puerto Rico, the U.S. Virgin Islands, and Guam. The EPA requests comment on how the BSER would apply to these territories, as well as to American Samoa or the Northern Mariana Islands if potentially affected EGUs are subsequently identified in those territories. In particular, the EPA solicits comment on appropriate alternatives for territories that do not have access to natural gas. | **34893** |
| State Goals | Because the data sources we have used for purposes of establishing renewable energy and demand-side energy efficiency targets for states do not cover all of the U.S. territories, we also solicit comment on ways to determine appropriate renewable energy and demand-side energy efficiency targets using other data sources. | **34893** |
| State Goals | We also recognize that at present EGUs report gross rather than net load 257 to us under 40 CFR Part 75, and that the proposed GHG standards of performance for new EGUs are expressed in terms of gross generation (although we sought comment on the use of net generation instead). We therefore specifically seek comment on whether the goals and reporting requirements for existing EGUs should be expressed in terms of gross generation instead of net generation for consistency with existing reporting requirements and with the proposed requirements under the GHG standards of performance for new EGUs. | **34894-34895** |

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| State Goals | We invite comment on all aspects of the proposed form of the goals. | **34895** |
| State Goals | The details of how states could attain emission performance levels consistent with the goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in Section VIII on state plans. We invite comment on all aspects of the goal computation procedure. (Note that we also invite comment on certain specific alternate data inputs to the procedure in Section VI.C above). We also specifically invite comment on the state-specific historical data to which the building blocks are applied in order to compute the state goals, as well as the state-specific data used to develop the state-specific data inputs for building blocks 3 and 4. | **34896-34897** |
| State Goals | With respect to building block 2, we specifically request comment on the following alternate procedure: In Step 3, to the extent that generation from a state's NGCC group was increased consistent with the NGCC utilization rate target, in order to maximize the resulting emission reductions, we would decrease generation from the state's coal-fired steam group first, and then decrease generation from the state's oil/gas-fired steam group (instead of decreasing generation from the coalfired steam and oil/gas-fired steam groups proportionately). | **34897** |
| State Goals | With respect to building block 4, we specifically invite comment on the alternative in Step 5 of scaling up the estimated reduction in the generation by affected EGUs in net electricity exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net electricity importing states described in Step 5. | **34897** |
| State Goals | We also request comment on the alternative of making no adjustment in Step 5 for either net electricity-importing or net electricity-exporting states. | **34897** |
| State Goals | We also request comment on whether $CO_2$ emission reductions associated with other measures not currently included in any of the four proposed building blocks should be included in the state goals. | **34897** |
| State Goals | States have the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data that is proposed for use in the computations. We expect that the states will have an adequate opportunity to comment on the state goals during the comment period. | **34898** |
| State Goals | In addition to the proposed statespecific emission rate-based goals described above, the EPA has developed for public comment an alternate set of goals reflecting less stringent application of the building blocks and a shorter implementation period. The alternate final goals represent emission performance that would be achievable by 2025, after a 2020–2024 phase-in period, with interim goals that would apply during the 2020–2024 period on a cumulative or average basis as states progress toward the final goals. | **34898** |
| State Goals | Accordingly, we request comment on the alternate goals, particularly with respect to whether any one or all of the building blocks in the alternate goals can be applied at a greater level of stringency: Can the heat rate improvement value be set at a level above four percent, even six percent? Can NGCC capacity be dispatched at a utilization rate above 65 percent? Can annual incremental electricity savings be achieved at a rate higher than one percent? | **34898-34899** |

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| State Goals | We request comment on whether, and if so how, the EPA should incorporate greater consideration of multi-state approaches into the goal setting process, and on the issue of whether, and if so how, the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness. | **34899** |
| State Goals | The flexibility inherent in the rule is responsive to the CAA's recognition that state plans for emission reduction can, and must, be consistent with a vibrant and growing economy and reliable, affordable electricity to support that economy. The EPA welcomes comments and suggestions on this issue. | **34900** |
| State Plans | The agency is soliciting comment on aspects of such CAA section 111(d) plans, as described in Section V.D of this preamble. | **34900** |
| State Plans | With this in mind, we are proposing to provide states with additional time to submit complete plans if they do so as part of a multistate plan, and we solicit comment on other potential mechanisms for fostering multi-state collaboration. | **34900** |
| State Plans | The EPA requests comment on this proposed approach, as opposed to the approach under which state plans simply would be required to hold the affected EGUs fully and solely responsible for achieving the emission performance level. | **34901** |
| State Plans | In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emission performance without rendering certain types of measures federally enforceable and that limit the obligations of the affected EGUs. | **34901** |
| State Plans | The EPA is also soliciting comment on whether it can reasonably interpret CAA section 111(d)(1) to allow states to adopt plans that require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level. | **34901** |
| State Plans | EPA requests comment on what we refer to as a ''state commitment approach.'' This approach differs from the proposed portfolio approach, described above, in one major way: Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. The agency requests comment on the appropriateness of this approach. | **34902** |
| State Plans | The agency also requests comment on the policy ramifications of the following: Under this approach, the state programs upon which the state bases its commitment may, in turn, rely on compliance by third parties, and if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges— including by citizen groups— for violating CAA requirements and, as a result, could be held liable for CAA penalties. | **34902** |
| State Plans | We also solicit comment on a variation of this state commitment plan approach that is also designed to address stakeholder concerns, noted above, about imposing sole legal responsibility on affected EGUs for achieving the emission performance level. | **34902** |
| State Plans | We solicit comment on whether, if the EPA were to conclude that CAA section 111(d) requires state plans to include standards of performance applicable to affected EGUs that achieve the emission performance level, this type of state plan would meet that requirement while also assuring those E. | **34902** |

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| State Plans | The EPA also requests comment on another approach: Whether ‘‘standards of performance for [affected sources]’’ is reasonably read to include the emission performance level (i.e., the state goal) on grounds that the level is ‘‘a standard for emissions’’ because it is in the nature of a requirement that concerns emissions and it is ‘‘for’’ the affected sources because it helps determine their obligations under the plan. | **34903** |
| State Plans | We solicit comment on the extent to which measures such as RE and demand-side EE may be considered ‘‘implement[ing]’’measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources. | **34903** |
| State Plans | The EPA solicits comment on all aspects of its proposed interpretation that states have this flexibility in selecting measures for their state plans under CAA section 111(d). | **34903** |
| State Plans | This alternative interpretation would be based on, for example: A determination that CAA section 111(d)(1) must be read as precluding a state plan from including measures that are neither standards of performance nor measures for the implementation or enforcement of such standards; an interpretation that the state’s obligation to set performance standards ‘‘for’’ existing sources means that the standards must apply to affected EGUs and not to other entities; and an interpretation that measures ‘‘for the implementation and enforcement of such performance standards’’ do not include measures that are not intended or designed to assist affected EGUs in meeting the performance standards. The EPA requests comment on whether it must adopt this alternative interpretation. If so, the EPA also takes comment on whether there is a way, nonetheless, to allow states to rely on the portfolio approach to some extent and/or for some period of time. | **34903** |
| State Plans | We request comment on all of the interpretations discussed in this section generally, and on all legal issues under CAA section 111(d)(1) with respect to what measures can be included in a state plan and what entities must be legally responsible for meeting those measures. | **34903** |
| State Plans | The EPA invites comments on this interpretation of CAA section 111(d)(1), including whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute. | **34904** |
| State Plans | In Section VIII.B.2.f of this preamble, the agency also requests comment on alternative requirements aimed at continued emission performance improvement after 2029. In Section VIII.B.2.g of this preamble, the EPA proposes flexibility for states to change from mass-based to rate-based goals in different performance periods and, in Section VIII.B.2.h, we solicit comment on planning requirements that match the option of alternative, less stringent state goals. | **34904** |
| State Plans | The agency requests comment on a second option in which, in addition to submitting a plan demonstrating emission performance through 2030, states would be required to make a second submittal in 2025 showing whether their plan measures would maintain the final-goal level of emission performance over time. If not, the state submittal would be required to strengthen or add to measures in the state plan to the extent necessary to maintain that level of performance over time. | **34905** |

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| State Plans | The EPA also requests comment on whether 2025, or an earlier or later year, would be the optimal year for a second plan submittal under the second option. | **34905** |
| State Plans | The agency generally requests comment on the appropriate start date and rationale for the plan performance period for the interim goal. | **34905** |
| State Plans | The agency invites comment on the proposed approach and other approaches to specifying performance periods for state plans. | **34906** |
| State Plans | The EPA requests comment on whether there are other types of state plans that should be considered ‘‘self-correcting.’’ | **34907** |
| State Plans | The EPA alternatively requests comment on whether states should be required to create legal authority and/or adopt regulations providing for corrective measures in developing the state plan. The agency requests comment generally on the conditions that should trigger corrective measure requirements. | **34907** |
| State Plans | For plans with corrective measures adopted into regulation prior to complete plan submittal, the agency solicits comment on whether actual emission performance inferior to projected performance by ten percent is the appropriate trigger for requiring a state to report the reasons for deficient performance and to implement corrective measures. We are also soliciting comment on the range of five percent to fifteen percent. | **34907** |
| State Plans | For plans without corrective measures adopted into regulation prior to complete plan submittal, the agency solicits comment on whether the proposed eight percent emission performance deviation trigger is appropriate. We also solicit comment on the range of five percent to ten percent. | **34907** |
| State Plans | The EPA also requests comment on the milestone approach and emission performance checks outlined in the context of the alternative 5-year performance period and the planning approach for alternative state goals. | **34907** |
| State Plans | For plans that rely in part on end-use energy efficiency programs and measures, the EPA requests comment on what a state would need to require in its plan to show that performance will be maintained after 2030. | **34908** |
| State Plans | The agency requests comment on how the consequences should vary depending on the reasons for a deficiency in performance. Specifically, the agency requests comment on whether consequences should include the triggering of corrective measures in the state plan, or plan revisions to adjust requirements or add new measures. | **34908** |
| State Plans | The agency requests comment on whether corrective measures, in addition to ensuring future achievement of the state goal, should be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal. | **34908** |
| State Plans | The agency requests comment on the process for invoking requirements for implementation of corrective measures in response to a state plan performance deficiency. | **34908** |
| State Plans | The EPA further requests comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. | **34908** |
| State Plans | The EPA proposes that a state must maintain the required level of performance and requests comment on the alternative of requiring continued improvement. | **34908** |

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| State Plans | The EPA is proposing a mechanism for implementing the objective that the level of emission performance for affected EGUs represented by the final goal be maintained in the years after 2030, and the EPA is requesting comment on an alternative approach to a state's pre-implementation demonstration that the final-goal level of emission performance will be maintained after 2030. | **34908** |
| State Plans | The EPA generally requests comment on appropriate requirements to maintain the emission performance of affected EGUs in years after 2030. | **34908** |
| State Plans | The EPA also requests comment on whether we should establish BSER-based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. | **34908** |
| State Plans | The agency requests comment on the appropriate time period(s) and final year for the EPA's calculation of state goals that reflect application of the BSER under this approach. | **34908** |
| State Plans | The EPA notes that CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources. This requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The agency requests comment on the implications of this concept, if any, for CAA section 111(d). | **34908** |
| State Plans | In Section VII, the EPA requests comment on alternative, five-year state emission performance goals for affected EGUs shown in Table 9. The alternative goals represent emission rates achievable on average during the 2020–2024 period, as well as emission rates to be achieved and maintained after 2024. These alternative goals are less stringent than the proposed goals in Table 8. To accompany the alternative goals, the EPA requests comment on another approach for state plan performance periods. | **34909** |
| State Plans | In connection with the alternative state goals, for the years after 2027, the EPA requests comment on the same ''out-year'' issues and concepts for maintaining or improving emission performance over time that are described above in Section VIII.B.2.f. The EPA requests comment on whether a state plan should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or whether a state should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance meeting the final goal for at least 10 years. In addition, the agency requests comment on the appropriate date for any second state plan submittal designed to maintain emission performance after the 2025 performance level is achieved. | **34909** |
| State Plans | The EPA requests comments on all aspects of these general approvability criteria and the twelve specific plan components described below. | **34909** |
| State Plans | We are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan. | **34909** |

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| State Plans | As discussed in section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). Also, as discussed in section VIII.F.4, the EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans. | **34909** |
| State Plans | We are seeking comment on whether, for state plans where emission limits applicable to affected EGUs alone would not assure full achievement of the required level of emission performance, the state plan must include additional measures that would apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance. | **34909** |
| State Plans | We request comment on all aspects associated with enforceability of a state plan and how to ensure compliance. We are also seeking comment on enforceability considerations under different state plan approaches, which is addressed in Section VIII.F.1. | **34909-34910** |
| State Plans | Existing ISOs and RTOs could provide a structure for achieving efficiencies by coordinating the state plan approaches applied throughout a grid region. In one possible approach, states would implement a multi-state plan and jointly demonstrate $CO_2$ emission performance by affected EGUs across the entire ISO/RTO footprint. States with borders that cross the boundary of one or more ISO or RTO footprints would need to include multiple plan components that address affected EGUs in each respective ISO or RTO. The EPA is seeking comment on this idea. States that are outside the footprint of an ISO or RTO may benefit from consulting with other relevant planning authorities when preparing state plans. We are also requesting comment on this idea. | **34910** |
| State Plans | We solicit comment on whether the process for implementing corrective measures should include the adoption of new plan measures and subsequent resubmission of the plan to the EPA for review and approval, or whether the process should specify the implementation of measures that are already included in the approved plan in the event that the projected level of performance is not being achieved. | **34910** |
| State Plans | We also solicit comment on the point at which such a process and schedule would be triggered, such as at the end of a multi-year plan performance period if emission performance is not met, or at specified interim stages within a multi-year plan performance period. | **34910** |
| State Plans | The EPA is requesting comment on the appropriate scope of these reporting requirements and whether the reports should also be directly submitted by the affected entities to the EPA, as well as to the state. | **34910-34911** |
| State Plans | We are also seeking comment on two additional options for multi-state plan submittals. | **34911** |
| State Plans | The EPA is seeking comment on whether states participating in a multi-state plan should also be given the option of providing a single submittal— signed by authorized officials from each participating state — that addresses common plan elements. Individual participating states would also be required to provide individual submittals that provide state-specific elements of the multi-state plan. | **34911** |
| State Plans | The EPA is seeking comment on an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. | **34911** |

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| State Plans | The EPA is seeking comment on two options for calculating a weighted average, rate-based $CO_2$ emission performance goal for multiple states. | **34911** |
| State Plans | We are requesting comment on whether, to assist states that seek to translate the rate-based goal into a mass-based goal, the EPA should provide a presumptive translation of rate-based goals to mass-based goals for all states, for those who request it, and/or for multi-state regions. | **34912** |
| State Plans | The agency is seeking comment on the process for establishing mass-based emission goals, including the options summarized above for the EPA's and states' roles in the translation process. | **34912** |
| State Plans | The EPA invites comment on technical considerations involved in translating rate-based goals to mass-based goals. | **34912** |
| State Plans | The agency requests comment on the amount of emission rate improvement or emission reduction that the corrective measures included in the plan must be designed to achieve (e.g., measures sufficient to address a 10 percent performance deficiency). | **34912** |
| State Plans | The agency also seeks comment on whether the emission guidelines should establish a deadline for implementation of corrective measures (e.g., two years from the July 1 deadline described above for reporting the deficiency as part of the state's annual report on plan performance). | **34912** |
| State Plans | We also solicit comment on longer and shorter averaging times for emission standards included in a state plan than those proposed (i.e., for a rate-based emission standard, no longer than 12 months within a plan performance period and, for a mass-based standard, no longer than 3 years). | **34913** |
| State Plans | As discussed in Section VIII.C.1, we are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan. | **34913** |
| State Plans | As discussed in Section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). | **34913** |
| State Plans | The EPA solicits comment on whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another state's demonstration of emission performance under its CAA section 111(d) plan. | **34913** |
| State Plans | However, we are seeking comment on two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported $CO_2$ emissions. | **34913** |
| State Plans | We solicit comment on whether EGUs producing both electric energy output and useful thermal output should be required to report both electric and useful thermal output. | **34914** |

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| State Plans | We invite comment on the proposal for reporting of net rather than gross energy output and on the proposed protocols. Specifically, we are seeking comment on: any existing protocols for reporting net output (FERC, NERC, etc.); electricity meter specifications; electricity meter quality assurance testing and reporting procedures; apportionment procedures for parasitic load at multi-unit facilities; treatment of externally provided electricity; and monitoring and quality assurance testing and reporting procedures for non-electric energy output at CHP units. | **34914** |
| State Plans | Consistent with the requests for comment in the proposed CAA section 111(b) GHG NSPS regulations for modified and reconstructed sources, we invite comment here on a range of two-thirds to 100 percent credit for useful thermal output in the final rule, or other alternatives to better align incentives with avoided emissions. | **34914** |
| State Plans | The EPA is proposing that state plans must include a record retention requirement of ten years, and we request comment on this proposed timeframe. | **34914** |
| State Plans | The EPA is requesting comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requests comment on whether full reports containing all of the report elements should only be required every two years. | **34914** |
| State Plans | The EPA is soliciting comment on whether reports should be submitted electronically, to streamline transmission. | **34914** |
| State Plans | The EPA is requesting comment on other circumstances for which an extension of time would be appropriate. We are also seeking comment on whether some justifications for extension should not be permissible. | **34915** |
| State Plans | We are requesting comment on the approach for extensions and the timing and frequency of updates that the state must provide. | **34915** |
| State Plans | The EPA is soliciting comment on whether there are other elements that a state must include in its initial submittal to qualify for a date extension. Specifically, the EPA requests comment on whether the guidelines should require a state to have taken significant, concrete steps toward adopting a complete plan for the initial plan to be approvable. | **34916** |
| State Plans | The EPA is requesting comment on whether, for complete state plans under these guidelines, the agency may use two approval mechanisms provided for in CAA sections 110(k)(3) and (4), 42 U.S.C. 7410(k)(3) and (4). First, where a CAA section 111(d) plan includes severable provisions, some of which are approvable and some of which are not, the EPA is requesting comment on whether the agency should interpret the CAA as providing the flexibility to approve those elements that meet the requirements of this guideline, while disapproving those elements that do not. Second, where a CAA section 111(d) plan is substantially approvable and requires only minor amendments to fully meet the requirements of these guidelines, the EPA is requesting comment on whether the agency should interpret the CAA as providing the flexibility to approve that plan on the condition that the state commits to curing the minor deficiencies within one year. | **34916** |

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| State Plans | The EPA requests comment on whether, for new projections of emission performance, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance. | **34917** |
| State Plans | The EPA is seeking comment on the creation of a template for initial and complete state plan submittals. A plan template would provide a framework that includes all of the necessary components for an initial and complete submittal that could be populated by states. | **34917** |
| State Plans | We are further seeking comment on whether a template may be more appropriate for initial plan submittals than complete plan submittals. | **34917** |
| State Plans | The EPA is also seeking comment on whether it should provide for, or require, electronic submittal of initial and complete plans. | **34917** |
| State Plans | We are seeking comment on the suitability of an approach such as that being used in the electronic state implementation plan submission (eSIPS) pilot program for submittal of state plans under CAA section 111(d). | **34917** |
| State Plans | The agency is seeking comment on the contents of the State Plan Considerations TSD and all aspects of the state plan decision points and factors. | **34917** |
| State Plans | We are seeking comment on other appropriate examples of affected entities beyond the affected EGUs. | **34917** |
| State Plans | We seek comment on whether the EPA should provide guidance on enforceability considerations related to requirements in a state plan for affected entities other than EGUs (and if so, which such entities). | **34917** |
| State Plans | While the EPA is proposing that a state may apply toward its required emission performance level the emission reductions that existing state programs and measures achieve during a plan performance period as a result of actions taken after the date of proposal of these emission guidelines, the EPA also requests comment on the following alternatives: the start date of the initial plan performance period, the date of promulgation of the emission guidelines, the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date. We are seeking comment on the point in time after which such actions should be able to qualify for use during a plan performance period, considering the method used to set state goals. | **34918** |
| State Plans | The EPA requests comment on whether there is a rational basis for choosing a date that predates the base period from which the EPA used historical data to derive state goals. The agency generally requests comment on the appropriate date to select under this option. | **34918** |
| State Plans | The EPA also solicits comment on a second broad option. This option would recognize emission reductions that existing state requirements, programs and measures achieved starting from a specified date prior to the initial plan performance period, as well as emission reductions achieved during a plan performance period. | **34918-34919** |
| State Plans | The EPA requests comment on this option – that emission reduction effects that occur prior to the beginning of the initial plan performance period could be applied toward meeting the required level of emission performance in a state plan. | **34919** |

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| State Plans | The agency requests comment on whether pre-2020 implementation of new requirements would be practical for states. The agency generally requests comment on this approach, including the conditions that should apply to pre-2020 emission reductions that would count toward the state goal. | **34919** |
| State Plans | The agency also requests comment on the alternative dates listed above in connection with this option. We also request comment on whether this option is inconsistent with the forward-looking method that the EPA has proposed for establishing state goals based on the application of the BSER. | **34919** |
| State Plans | The agency is seeking comment on whether some variation of this approach could be justified as consistent with the EPA's proposed goal-setting approach, as well as the general concept of the BSER and its application in establishing state goals. | **34919** |
| State Plans | We are seeking comment on whether the emission effects of actions that are taken after proposal or promulgation of the emission guidelines or the approval of a state plan, but which occur prior to the beginning of the initial state plan performance period, could be applied toward meeting the required level of emission performance in a state plan. | **34919** |
| State Plans | We are seeking comment on different approaches for providing crediting or administrative adjustment of EGU $CO_2$ emission rates, which are elaborated further in the State Plan Considerations TSD. | **34919** |
| State Plans | We invite comment on each of these possible approaches. | **34920** |
| State Plans | Because some of the $CO_2$ emissions avoided through RE and demand-side EE measures may be from non-affected EGUs, we are seeking comment on how this might be addressed in a state plan, whether when adjusting or crediting $CO_2$ emission rates of affected EGUs based on the effects of RE and demand-side EE measures or otherwise. | **34920** |
| State Plans | We are seeking comment on the suitability of these approaches in the context of an approvable state plan, and on whether harmonization of state approaches, or supplemental actions and procedures, should be required in an approvable state plan. In particular, we intend to establish guidance for acceptable quantification, monitoring, and verification of RE and demand-side EE measures for an approvable EM&V plan, and are seeking comment on critical features of such guidance, including scope, applicability, and minimum criteria. We are also seeking comment on the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols. | **34921** |
| State Plans | The EPA is requesting comment on the merits of this approach, including whether such guidance should identify types of RE and demand-side EE measures and programs for which evaluation of results is relatively straightforward and which are appropriate for inclusion in a state plan. | **34921** |
| State Plans | As an alternative to the EPA's proposed approach of allowing a broad range of RE and demand-side EE measures and programs to be included in state plans, provided that supporting EM&V documentation meets applicable minimum requirements, the EPA is requesting comment on whether guidance should limit consideration to certain well-established programs, such as those characterized in Section V.A.4.2.1 of the State Plan Considerations TSD. | **34921** |
| State Plans | We are seeking comment on the examples and suitability of potential approaches described in the State Plan Considerations TSD and any other appropriate reporting and recordkeeping requirements for affected entities beyond affected EGUs. | **34921** |

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| State Plans | The EPA is seeking comment on the options for treatment of interstate effects summarized below, as well as alternatives. | **34921** |
| State Plans | We also request comment on whether a state should be able to take credit for emission reductions out of state due to in-state EE measures if the state can demonstrate that the reductions will not be double counted when the relevant states report on their achieved plan performance, and what such a demonstration should entail. | **34922** |
| State Plans | We request comment on these and other approaches for taking into account $CO_2$ emission reductions from demand-side EE measures in state plans. | **34922** |
| State Plans | The EPA is also seeking comment on how to avoid double counting emission reductions using the proposed approach for accounting for $CO_2$ emission reductions from renewable energy measures implemented by the state. | **34922** |
| State Plans | We also request comment on the option of allowing a state to take into account only those $CO_2$ emission reductions occurring in its state. | **34922** |
| State Plans | We also request comment on whether a state should be able to take credit for emission reductions out of state due to renewable energy measures if the state can demonstrate that the reductions will not be double counted when the relevant states report on their achieved plan performance, and on what such a demonstration should entail. | **34922** |
| State Plans | We request comment on these and other approaches for taking into account $CO_2$ emission reductions from renewable energy measures. | **34922** |
| States Plans | We are seeking comment on the considerations discussed in the Projecting EGU $CO_2$ Emission Performance in State Plans TSD, including options presented for how projections might be conducted in an approvable state plan, and how different types of state plan approaches are represented in these projections. | **34923** |
| State Plans | We are seeking further comment on whether the EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as providing technical resources for conducting projections. | **34923** |
| State Plans | The agency solicits comment on whether certain other measures not used to set state goals are appropriate to include in a state plan to achieve $CO_2$ emission reductions from affected EGUs. In addition to the specific requests for comment related to specific technologies identified, we also request comment on other measures that would be appropriate. In addition, we request comment on whether the EPA should provide specific guidance on inclusion of these measures in a state plan. | **34923** |
| State Plans | The agency requests comment on alternative nuclear capacity baselines, including whether the date for recognizing additional non-BSER nuclear capacity should be the end of the base year used in the BSER analysis of potential nuclear capacity (i.e., 2012). | **34923** |
| State Plans | This proposal does not include new NGCC as a component of the BSER, but the agency requests comment on that in Section VI of this preamble. | **34923** |

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| State Plans | The agency requests comment on how emission changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. | **34924** |
| State Plans | With respect to new fossil fuel-fired EGUs, the agency also requests comment on the concept of providing credit toward a state's required CAA section 111(d) performance level for emission performance at new CAA section 111(b) affected units that, through application of CCS, is superior to the proposed standards of performance for new EGUs. | **34924** |
| State Plans | We invite comment on whether incremental emission reductions from new fossil fuel-fired boilers and IGCC units with CCS, based on exceeding the CAA section 111(b) performance standards for such units, should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan. | **34924** |
| State Plans | We invite comment on whether incremental emission reductions from new NGCC units that outperform the performance standards for such units under CAA section 111(b) based on the use of CCS should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan. | **34924** |
| State Plans | The agency requests comment on whether industrial combined heat and power (CHP) approaches warrant consideration as a potential way to avoid affected EGU emissions, and whether the answer depends on circumstances that depend on the type of CHP in question. | **34924** |
| State Plans | The EPA requests comment on whether there are still other areas beyond those discussed above for which it would be useful for the EPA to provide guidance. | **34924** |
| State Plans | The agency is requesting comment on its analysis of the implications of the EPA's existing regulations interpreting ''useful life'' and ''other factors'' for purposes of this rulemaking. The agency also requests comment on whether it would be desirable to include in regulatory text any aspects of this preamble discussion about how the provisions in the existing implementing regulations concerning source-specific factors relate to this emission guideline. | **34925** |
| State Plans | To the extent that a performance standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state is free to make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions), as part of the state's CAA section 111(d) plan submission. The agency requests comment on its interpretation. | **34925-34926** |
| State Plans | The EPA proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. The agency solicits comment on this position. | **34926** |
| State Plans | The EPA solicits comment on the approach for providing decision support resources and the information currently included, and planned for inclusion, in the Decision Support Toolbox. | **34928** |

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| Implications for Other EPA Programs | We request comment on whether, with adequate record support, the state plan could include a provision, based on underlying analysis, stating that an affected source that complies with its applicable standard would be treated as not increasing its emissions, and if so, whether such a provision would mean that, as a matter of law, the source's actions to comply with its standard would not subject the source to NSR. We also seek comment on the level of analysis that would be required to support a state's determination that sources will not trigger NSR when complying with the standards of performance included in the state's CAA section 111(d) plan and the type of plan requirements, if any, that would need to be included in the state's plan. | **34928-34929** |
| Small Businesses | We invite comments on all aspects of the proposal and its impacts, including potential impacts on small entities. | **34947** |
| Federalism | In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from State and local officials. | **34948** |
| Tribal | We specifically solicit comment from tribal officials on this proposed rule. | **34948** |
| National Technology Transfer and Advancement | This proposed rulemaking does not involve voluntary consensus standards – technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA welcomes comments on this aspect of the proposed rulemaking and specifically invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this action. | **34949** |
| Environmental Justice | The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of exposure to the pollutants addressed by this proposal. | **34950** |

# Appendix E

## Transmission Reliability Related

# Transmission Challenges with the Clean Power Plan

American Electric Power
September 2014

# Three Principles of Power Systems

AEP AMERICAN ELECTRIC POWER

1. The interconnected electric power system functions as a single, large, dynamic machine – extending thousands of miles
2. Changes in any one portion of the system instantly affect the operation of all other portions
3. Future plans for any one part of the system will affect many other parts of the system

# System Operating Limits

- There are three types of limits that must be assessed:
  1. Thermal – line conductors and substation equipment have a finite limit of how much current they can carry
  2. Voltage – all electric equipment is designed to work within a specific voltage range, deviating from these limits can cause issues with the operation of the equipment
  3. Stability – the electric power grid is a dynamic machine with its own limits defined by its inter-connected structure and the electro-mechanical equipment within it; deviating from these limits can lead to system-wide issues
     - Voltage Stability – the ability of the system to balance reactive power sources and sinks to maintain steady acceptable voltages
     - Angular Stability – the ability of the system to balance the torques and forces acting on it and remain synchronized

*Operation of the power system in violation of these limits places the system at risk for cascading outages, voltage collapse and ultimately blackouts.*

# Complex Analytics Required

AEP AMERICAN ELECTRIC POWER

- **Power-flow Analysis**
  Used to evaluate the power system in a "steady-state", and determine the voltage at each system node and the power flowing through all lines in the system
  - Requires a model of the inter-connected power grid
  - Can be done on future-looking models of the grid
  - Numerous scenarios need to be carefully reviewed to assess the "full-picture" of system impacts
  - Gives guidance on optimal system improvements to implement

- **Stability Analysis**
  Used to evaluate the dynamic response of the power system to disturbances (faults, facility outages, loss of load, etc.)
  - Requires a model of the inter-connected power grid
  - Requires details of control parameters from generating plants and other dynamic devices
  - Gives guidance on dynamic system limits and whether additional system improvements are necessary

*Power system operates as a non-linear, dynamic machine and requires sophisticated, complex analytics to model and study its performance.*

# Transmission Planning Standards

- NERC Reliability Standards define the reliability requirements for planning and operating the bulk power system
  - See Appendix for additional detail on the planning standards
- RTOs / Planning Entities apply the NERC Standards, in addition to their own criteria, to assess the adequacy and security of the system under anticipated future scenarios
- Transmission Owners apply their own planning criteria, as defined in FERC Form 715, to assess the reliability performance on the facilities not covered by the RTOs/Planning Entities

*Enhancements to the transmission system are driven by the application of the planning criteria through complex analytical studies.*

# Preliminary Study

- Purpose of the assessment was to get a "quick look" at the potential impact of the Clean Power Plan on the AEP Transmission Grid
- The focus was on the AEP East system that is in the PJM RTO
- Modeled EPA's Option 1 retirement scenario with replacement generation added based on the PJM queue
- Performed N-1, Generation Deliverability and N-1-1 assessments
- The analysis and results should be considered preliminary and the mitigation plans should be considered indicative and conservative

*Utilized the approach the RTO would take to study the performance of the transmission system under these conditions.*

# EPA Option 1 Results in Severe Reliability Problems

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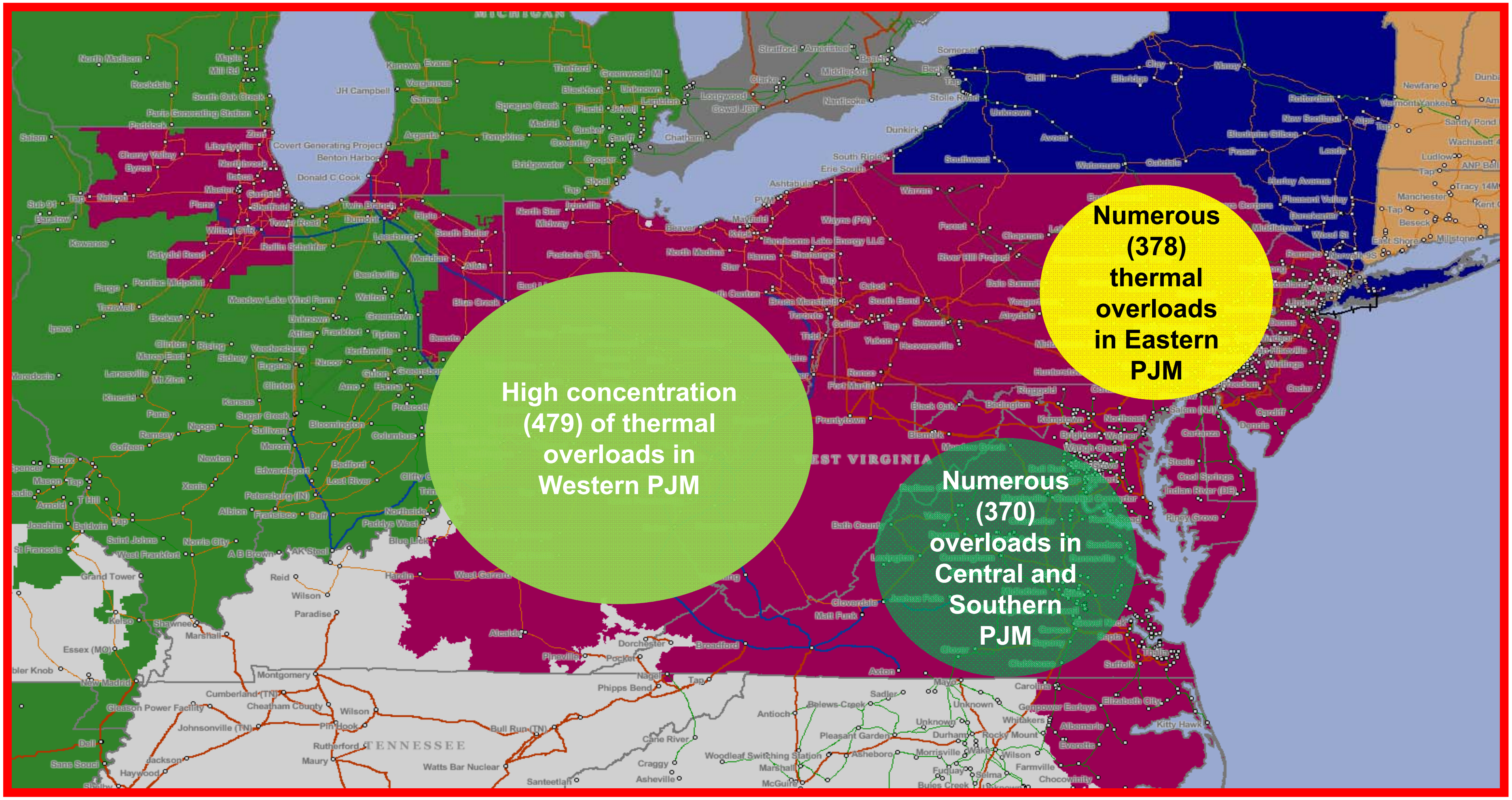

# Preliminary Study Results

- Preliminary analysis identified severe, widespread reliability concerns across the PJM footprint
- Problems consisted of thermal overloads, low voltages, and voltage collapse leading to cascading outages
- Constraints on the AEP system alone would require between $1B and $2B to resolve
- Study results are likely to be conservative
  - Assumes all queued generation would be constructed
  - Nearly all new generation is located in the east and is natural gas
  - Significantly more renewable generation must be added to meet requirements of CPP, additional wind will add further stress to the grid
- Interregional impacts have not been assessed
  - Need to include MISO, TVA, Duke Carolinas and NYISO post CPP resource plans to capture interregional impact
  - This will be significant given the interregional nature of the grid

# AEP Preliminary Analysis of SPP

- Evaluated the impact of the EPA's projected retirements on the reliability of the SPP region
- Generation assumptions
  - EPA Option 1 State Simulation 2020
  - New gas fired and wind generation added
- Preliminary Results
  - The SPP system is severely stressed by large reactive power deficiencies, generally indicative of voltage collapse and blackout conditions
  - Severely overloaded elements in Texas, western Kansas and eastern Oklahoma leading to cascading outages and voltage collapse

# Disruptive & Unprecedented

AEP AMERICAN ELECTRIC POWER

- The interconnected electric power system functions as a single, large, dynamic machine – extending thousands of miles
  - Disruptive changes in supply mix will have a dramatic impact on the reliability of the transmission system
- Changes in any one portion of the system instantly affect the operation of all other portions
  - Detailed technical analysis required to evaluate and address the impacts
  - Preliminary analysis suggests widespread reliability challenges
  - In many situations, the software could not solve
- Future plans for any one part of the system need to consider impacts on the entire network
  - Transmission analysis will require a regional assessment due to the interconnected nature of the grid
  - Unprecedented coordination and cooperation beyond current regional planning efforts will be necessary
- Implementation of approved state plans will take time, as will potential mitigation measures to address unacceptable system conditions to accommodate retirements
  - Time frame required to address the transmission issues is 5 to 10 years once the generation plan is figured out
  - Reliable operation of the grid will be threatened if adequate time is not given

# ADDITIONAL MATERIAL

# Power System Reliability

- **Reliable Operation**
  Operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

- Systems are planned using the NERC TPL standards. The following criteria form the foundation:
  - N-1: Ensure the system can withstand the loss of a single facility
  - N-1-1: Ensure the system voltages can stay within limits following the back-to-back loss of facilities
  - Generation Deliverability: Ensures the generation is deliverable to the RTO footprint and can be considered a capacity resource

# The Interconnected Grid

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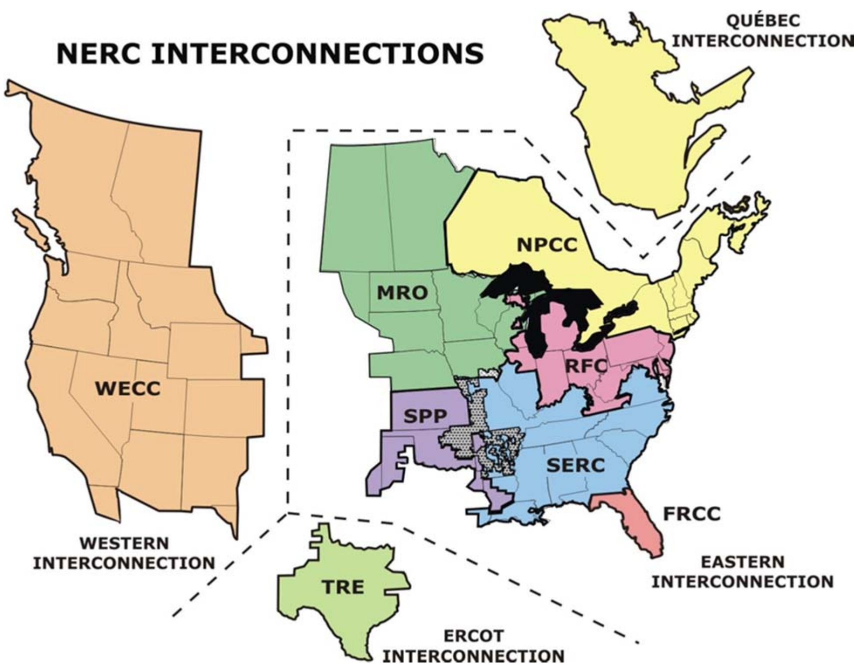
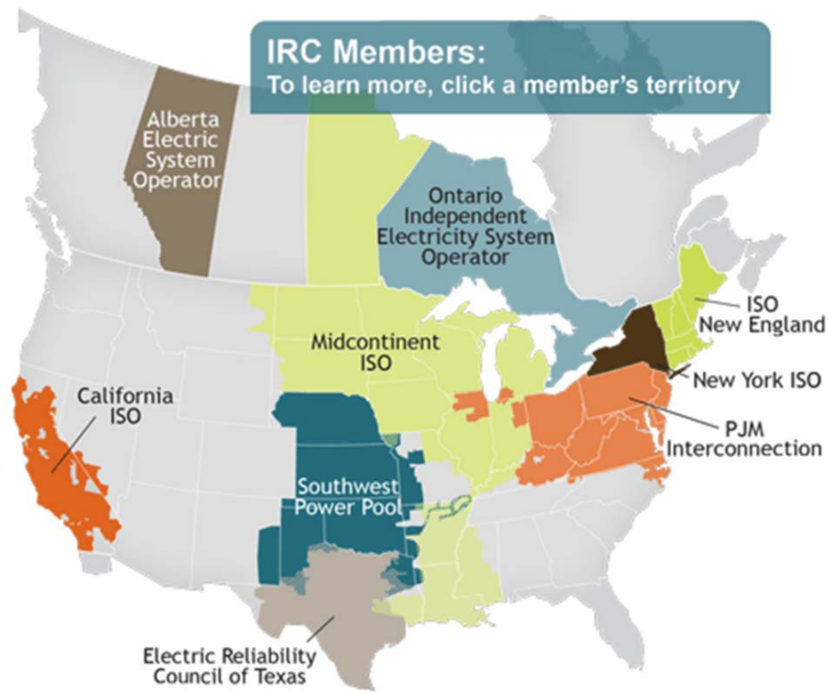
**Synchronous Interconnections**

**RTOs / ISOs**

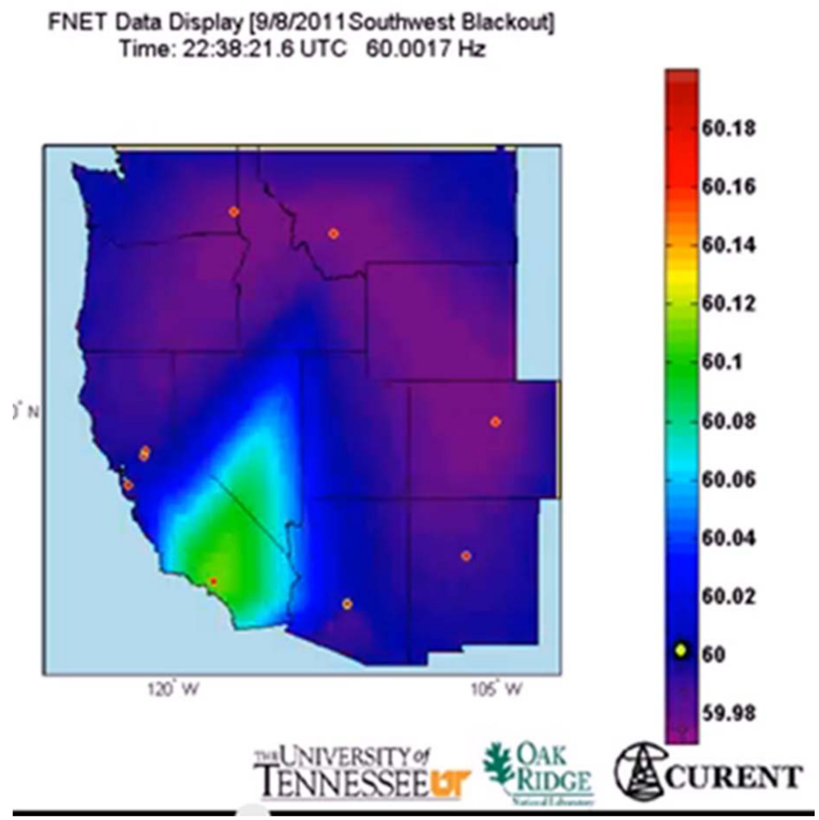


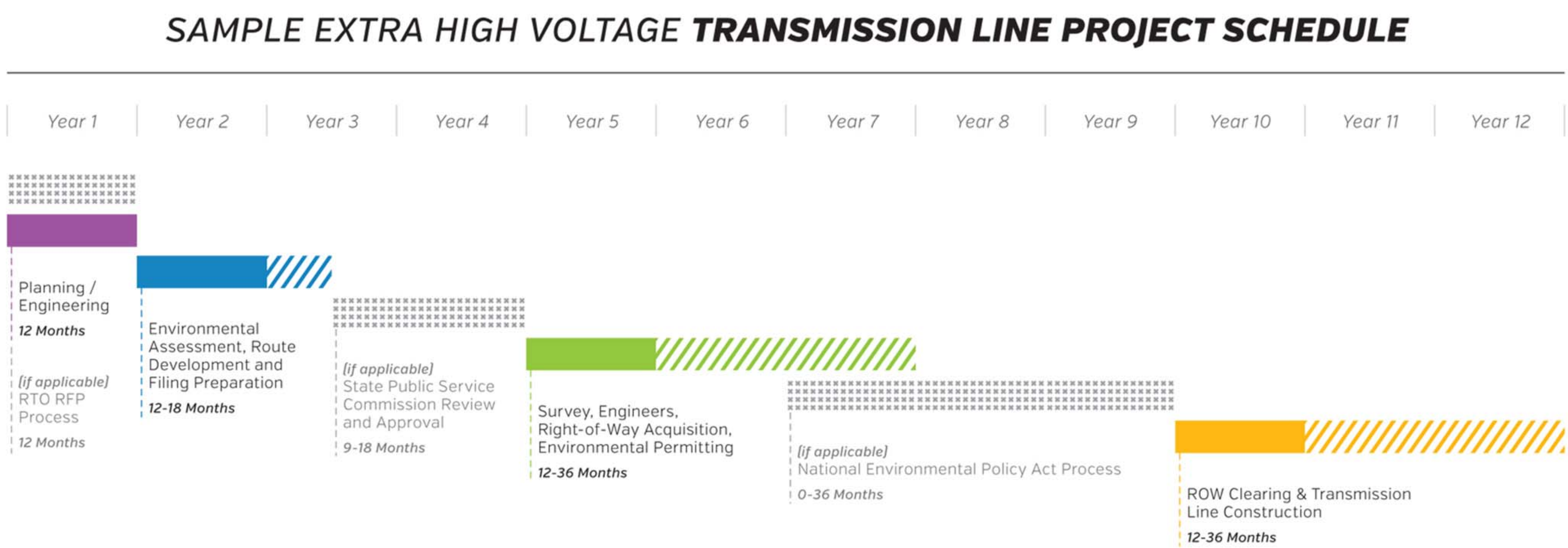

*Due to the highly interconnected nature of the Transmission system, it must be planned on a regional / interregional basis.*

# The Interconnected Grid

- The Inter-Connected Grid is a Dynamic Machine
  - Local events and changes can have national impacts
- Sample Events
  - Measured and simulated by the Power IT Lab at the University of Tennessee (Knoxville) using PMUs and PSS/e
  - Southwest Blackout – 2011
    - http://www.youtube.com/watch?v=YsksUyeLu2Y
  - Florida Outage - 2008
    - http://www.youtube.com/watch?v=bdBB4byrZ6U
  - Northeast Blackout – 2003
    - http://www.youtube.com/watch?v=eBucg1tX2Q4



# Project Schedule Timeline



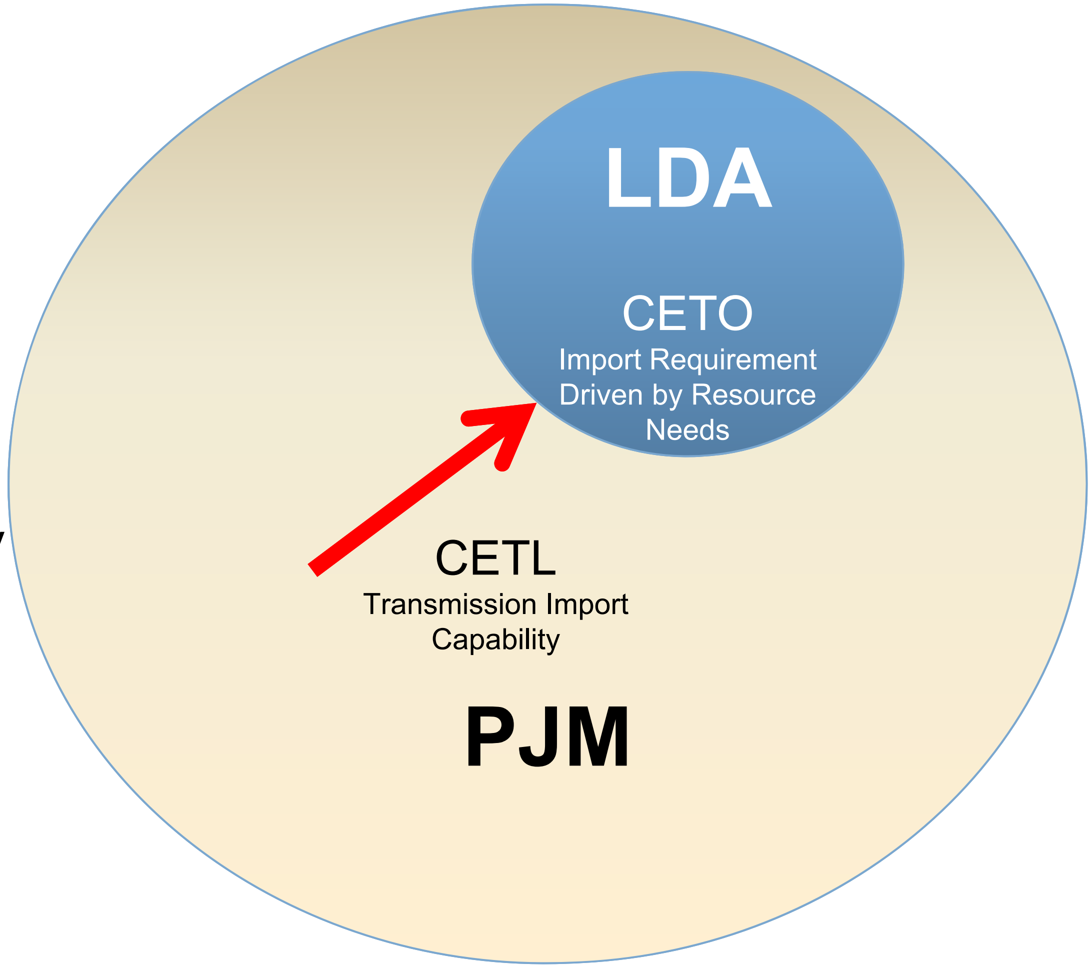

- *A transmission project lifecycle can vary significantly depending upon the type of project and where it is being built.*
- *The nature of the project (for example, its voltage and length), trigger different regulatory processes in different areas.*
- *Some, but not all, states review applications and issue permits for construction.*
- *Environmental issues, necessary permits and crossing public lands widely affect the process.*
- *Projects that require a National Environmental Policy Act review can plan on adding one to three years, or more, to the process.*

# PJM Capacity Market

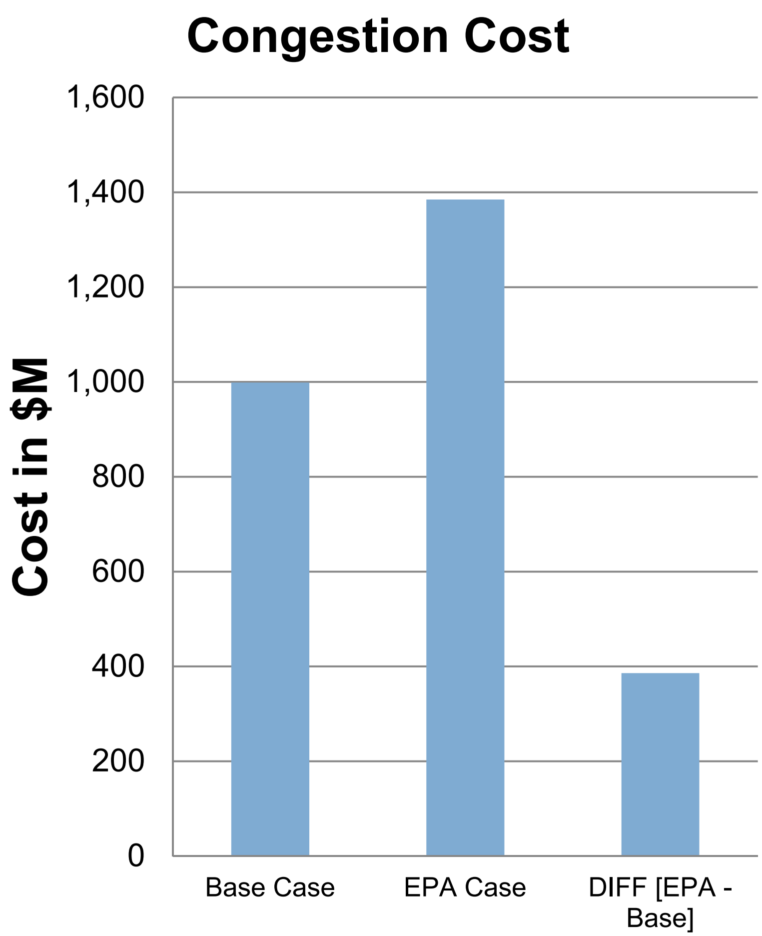
If $\frac{\text{CETL}}{\text{CETO}} \leq 1.15$

then LDA is capacity constrained

- Transmission capability key to ensuring generation deliverability
- Constrained transmission can create price separation and increased costs



# Energy Market Impacts




- Change in generation resource mix created increased congestion cost
- Preliminary analysis suggested an incremental $400M annually
- Congestion costs likely to be higher when the renewable requirements are included
- Additional transmission will be needed to reduce the congestion costs

# NERC Reliability Principles

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **Reliability Principle 2** — The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- **Reliability Principle 3** — Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
- **Reliability Principle 4** — Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
- **Reliability Principle 5** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk electric systems.
- **Reliability Principle 6** — Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
- **Reliability Principle 7** — The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

# NERC Market Interface Principles

- **Market Interface Principle 1** — The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy.
- **Market Interface Principle 2** — An Organization Standard shall not give any market participant an unfair competitive advantage.
- **Market Interface Principle 3** — An Organization Standard shall neither mandate nor prohibit any specific market structure.
- **Market Interface Principle 4** — An Organization Standard shall not preclude market solutions to achieving compliance with that standard.
- **Market Interface Principle 5** — An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

# NERC TPL Standards – Table 1

**Table 1 – Steady State & Stability Performance Planning Events**

**Steady State & Stability:**

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

**Steady State Only:**

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

**Stability Only:**

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

| Category | Initial Condition | Event [1] | Fault Type [2] | BES Level [3] | Interruption of Firm Transmission Service Allowed [4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P0**<br>No Contingency | Normal System | None | N/A | EHV, HV | No | No |
| **P1**<br>Single Contingency | Normal System | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer [5]<br>4. Shunt Device [6] | 3Ø | EHV, HV | No[9] | No[12] |
| | | 5. Single Pole of a DC line | SLG | | | |
| **P2**<br>Single Contingency | Normal System | 1. Opening of a line section w/o a fault [7] | N/A | EHV, HV | No[9] | No[12] |
| | | 2. Bus Section Fault | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 3. Internal Breaker Fault [8] (non-Bus-tie Breaker) | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 4. Internal Breaker Fault (Bus-tie Breaker) [8] | SLG | EHV, HV | Yes | Yes |

# NERC TPL Standards – Table 1

| Category | Initial Condition | Event[1] | Fault Type[2] | BES Level[3] | Interruption of Firm Transmission Service Allowed[4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P3**<br>Multiple Contingency | Loss of generator unit followed by System adjustments[9] | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer[5]<br>4. Shunt Device[6] | 3Ø | EHV, HV | No[9] | No[12] |
| | | 5. Single pole of a DC line | SLG | | | |
| **P4**<br>Multiple Contingency<br>*(Fault plus stuck breaker[10])* | Normal System | Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer[5]<br>4. Shunt Device[6]<br>5. Bus Section | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus | SLG | EHV, HV | Yes | Yes |
| **P5**<br>Multiple Contingency<br>*(Fault plus relay failure to operate)* | Normal System | Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer[5]<br>4. Shunt Device[6]<br>5. Bus Section | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| **P6**<br>Multiple Contingency<br>*(Two overlapping singles)* | Loss of one of the following followed by System adjustments.[9]<br>1. Transmission Circuit<br>2. Transformer[5]<br>3. Shunt Device[6]<br>4. Single pole of a DC line | Loss of one of the following:<br>1. Transmission Circuit<br>2. Transformer[5]<br>3. Shunt Device[6] | 3Ø | EHV, HV | Yes | Yes |
| | | 4. Single pole of a DC line | SLG | EHV, HV | Yes | Yes |

# NERC TPL Standards – Table 1

| Category | Initial Condition | Event [1] | Fault Type [2] | BES Level [3] | Interruption of Firm Transmission Service Allowed [4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P7**<br>Multiple Contingency<br>*(Common Structure)* | Normal System | The loss of:<br>1. Any two adjacent (vertically or horizontally) circuits on common structure [11]<br>2. Loss of a bipolar DC line | SLG | EHV, HV | Yes | Yes |

# Appendix E

# Regulatory Impact Analysis Related

**<u>Comments of American Electric Power</u>**

**Technical Support Document, Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866**

**Submitted Electronically to: The Office of Management and Budget**

**Attention: Docket OMB-OMB-2013-0007**

**February 26, 2014**

## Summary

American Electric Power (AEP) believes the Social Cost of Carbon (SCC) is inadequate and flawed mechanism to monetize benefits that may accrue from reductions in domestic greenhouse gas emissions. The lack of transparency in model development, lack of peer review, as well as the inclusion of a broad number of unsubstantiated assumptions makes the SCC values developed highly speculative and not appropriate for use in policy development or Regulatory Impact Analysis. Additionally, the post-processing of the Integrated Assessment Model (IAM) results, using averages of various model outputs and scenarios, is completely arbitrary for the evaluation of emission reduction benefits. Furthermore, the model's geographic scope and time period analyzed in development of the SCC values is completely inconsistent with corresponding analysis of regulatory costs. Until these issues can be resolved with firm scientific and public consensus or an alternative valuation system be developed, the SCC should not continue to be used in Regulatory Impact Analysis. AEP encourages the Interagency Working Group to explore alternative systems to more appropriately value carbon costs and benefits in the future.

## The Use of Integrated Assessment Models for SCC Value Calculations is Highly Problematic

Underpinning the Social Cost of Carbon values are Integrated Assessment Models (IAMs), which are designed to evaluate the interplay between environmental impacts and economic conditions. These models were developed to explore the possible future trajectories of human and natural systems, answer key questions regarding climate policy development, coordinate assumptions and identify future research needs. As the IAM models are designed for largely exploratory purposes, many of their assumptions and functions still lack a firm routing in proven scientific or economic theory at this point. The Interagency Working Group has pointed this fact out numerous times in the SCC technical documentation and concludes they are in fact "imperfect and incomplete." IAMs are not meant to be predictive tools but rather producers of what-if scenarios of an evolving world.

While the IAM models used to develop the Social Cost of Carbon have been routinely cited in peer-reviewed literature, it is unclear that the models have been subject to direct peer review. As the assumptions play a paramount part in driving the results and conclusions, each assumption parameter and variable needs to be appropriately documented and peer reviewed. This type of work is already done with many models used to calculate policy costs, such as the IPM model used by EPA, and a similar structure should be followed for the IAM models. The lack of consistency and consensus as to these assumptions is evident in the inconsistent and conflicting results of different model running the same scenarios. As an example, in the low temperate increase scenario, one of the models predicts net benefits while two other models predict significant costs. Furthermore, past assessments of IAM model results have concluded that the calculated climate damages are often derived from very different sources (e.g. market, non-market & catastrophic) suggesting further disagreement and inconsistency.[1] **These conflicts need to be reconciled before the model outputs can be deemed ripe for use in regulatory development or analysis.**

**Economic Damage Functions used to Calculate the SCC are Highly Speculative**

The IAM models are populated with a chain of assumptions and functions used to translate Greenhouse Gas (GHG) emissions into changes in atmospheric GHG concentrations, GHG concentrations into temperature changes and temperature changes into economic damages. These estimates include economic growth, emissions projections, carbon cycle response, atmospheric concentrations, climate sensitivity, temperature increases, weather effects, and damage functions. The use of damage functions is particularly troubling as there is only a small amount of economic theory and literature to support them and what supporting literature has been developed is not necessarily representative globally. Additionally, the types of damages assessed appear to vary greatly between the three IAM models.

Robert Pindyck perhaps best characterized this situation in stating: “damage functions used in most IAMs are completely made up, with no theoretical or empirical foundation.”[2] The Interagency Working Group substantiates these findings concluding there is a “limited amount of research linking climate impacts to economic damages” and that there is “the need for additional research.” **However, the avoided economic damages pulled from the IAM models are in fact the sole output that is used to derive SCC values. Thus the SCC values are inherently rooted in incomplete science and economic theory.**

**IAM Models Fail to Adequately Account for Climate Adaptation**

There is also concern about how the IAMs incorporate adaptation as a means to abate economic damage. First, there is no consistent framework for treating adaptation between the three models, which may account for the significant difference in model results. Also, it appears some abatement opportunities are treated exogenously while others are treated endogenously. Many of these assumptions surrounding abatement appear to be crude and arbitrary with no recognition of increased technical abilities likely to emerge in the future. Additionally, it does not appear abatement opportunities are characterized for each sector in which damages may be calculated. **There needs to be**

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[1] Joseph E. Aldy, et al, “Designing Climate Mitigation Policy”, Resources For the Future, RFF DP 08-16, May 2009. P. 50. http://www.rff.org/RFF/Documents/RFF-DP-08-16.pdf

[2] Robert S. Pindyck, “Climate Change Policy: What Do The Models Tell Us?” National Bureau of Economic Research, Working Paper 19244, July 2013.

**further research into adaptation functions to ensure that the estimated damages are not significantly overstating the true economic cost of climate change.**

**The Emission/Economic Scenarios Bias SCC results to Improbably High Values**

Five emission and economic scenarios were modeled in development of the Social Cost of Carbon, based on EMF-22 scenarios, representing a range of emission trajectories. However, four out the five scenarios suggest that emissions will continue to rise largely unabated through 2100, reflecting in the words of the Interagency Working Group, business as usual (BAU) or an emission "pathway absent mitigation policies." This seems widely inconsistent with both current U.S. policy objectives and plausible reality.

Actions by the U.S., European Union, Japan, Australia and a number of other nations to abate emissions show that there is a growing consensus that climate action is taking place and further action is needed going forward. This would suggest that the high emission growth scenarios are likely not to occur due to action already occurring and likely to continue in more substantial fashion going forward with other nations beginning to plan for emission reduction pathways, most notably the world's largest GHG emitter, China.

In the high unlikelihood that large-scale international climate action does not occur in the next few decades, there still remains a large number of years (until the end of the IAM assessment period in 2300) in which to better and more precisely detect actual climatic impacts, characterize future climatic impacts and conclude that emission reduction actions or adaptation measures are needed. These actions could dramatically change the emission and temperature trajectories and thus static assumptions on emission trajectories, particularly those extrapolated post-2100 are highly arbitrary and likely not to transpire. **These conclusions regarding climate action suggest that the BAU scenarios used in SCC development are in fact not likely and are skewing the damages to higher values than otherwise probable.**

The choice of running the IAM model scenarios out to the year 2300 is also concerning. While CO2 has a long atmospheric lifetime and the carbon cycle has inertial effects, making assumptions about socioeconomic factors and climatic factors over such a long time horizon is very tenuous at best. In fact, all data past 2100 is extrapolated, as EMF-22 assumption data ends at that point. To suggest that trends continue in a linear or constant fashion out until 2300 is highly arbitrary. The world of 2300 is likely to look much different that today, thus using assumption and linkages supported by narrow bands of data today may not be technically sound in a much different future. **AEP would suggest using a shorter time for analysis in which the assumptions can be more readily supported.**

**U.S. Specific SCC Values should be used for U.S. Regulatory Evaluations NOT Global Values**

In addition to the uncertainty in regional IAM model assumptions, inputs and outputs, there no regional differentiation of the ultimate model results. Simply assuming that the U.S. bears a proportion of the global economic damages is highly arbitrary and almost certainly wrong. **Social Cost of Carbon**

**values for use in U.S. specific analysis should be derived solely from calculated U.S. economic damages.**

Most economists would agree that due to the high level of economic development within the U.S., the U.S. will be better able to adapt and respond to any climatic effects than less developed countries. This suggests using an average marginal global value, in addition to being incorrect in practice, is likely significantly overstating the marginal damages that may accrue to the U.S.

The sensitivity of the results to discount rate indicates that some of the major economic damages may not occur until well into the future. **The undiscounted impacts should be disclosed on a year-by-year basis to allow for evaluation of the timing of impacts over such as long time horizon.** This will better aid policy makers in making balanced policy decisions affecting current society given the uncertainty in the projections. Additionally, there is concern with using discount rates below previous guidance given by OMB.

**The Development of SCC Values is Not Analytically Correct**

As stated previously, IAMs are not meant to be predictive tools, but rather producers of what-if scenarios in an evolving world. However, in the case of the Social Cost of Carbon, a methodology is employed to use model outputs to produce absolute values regarding the level of carbon abatement that is current economically optimal. **As a result of the SCC development process and the focus on a central value for regulatory analysis, the models are in-fact being used as a predictive tool, which is not what they are designed for.**

The Social Cost of Carbon values are based the average marginal abatement values across the three models and the five socioeconomic scenarios for each discount rate. It is improper to use such a wide range of emission scenarios in the modeling process in the development of the SCC. While there is uncertainty of future international action, as previously commented upon, one must assume that current political efforts and basic human nature in response to impending impacts will in fact result in emission reductions, particularly given the long time horizon for analysis, leading to lower and narrower emission paths than currently assessed. The wide-band of scenarios currently analyzed also accentuates any tail-effects the models may pick up from scenarios with high levels of temperature increase and skew the average.

Due to the inconsistent results and wide range of impacts, averaging the model outputs is a not a statistically sound way to aggregate the data. Extreme values in certain model scenarios drive average values higher. Absent evidence these extreme values not outliers, using a median value approach may be more statistically sound in developing a central value. However the publishing of undiscounted damage values and types of impacts expected would allow for proper assessment of the statistical method required, taking into account risk tolerance.

There is considerable uncertainty as to the proper discount rate to use for intergenerational accounting, but the discount rate used in climate change cost-benefit analysis is highly important given the fact, that as currently modeled, the majority of damages appear to be loaded in later years. Use of a low discount rate would suggest allocation of current capital resources to emission abatement efforts at the expense of current growth as higher yielding near-term investments might not be allocated capital. This is concerning in light of all the uncertainty in the models. As mentioned previously, several of the discount rates used currently used are lower than OMB guidance.

**Costs-Benefits Do Not Match Spatially or Temporally**

As mentioned previously, the SCC values are established based on a global measure of benefits. This is inconsistent with current policy as to benefit evaluation of domestic regulation, which is calculated on solely a U.S. basis, based on guidance given through Executive Orders. Potential costs or benefits to other nations are not assessed within analysis of domestic policy. In order for a proper cost-benefit test to be conducted, **both cost and benefit analysis should be conducted with the same geographic scope.** As U.S. regulations are meant to protect the rights of U.S. citizens and residents both costs and benefits should be evaluated on solely the basis of domestic impact. Matching geographic scope is especially important with respect to carbon emissions, as emission leakage is a well-established phenomenon, as discussed later.

The SCC values being developed based on modeling out until the year 2300 also creates a major temporal disconnect between how costs and benefits are evaluated. Typical cost analysis of regulatory proposals only runs for a decade or two at most, with most Regulatory Impact Analyses citing uncertainty or lack of concrete data beyond that point preventing longer-term analysis. **While, it is encouraged that the SCC analysis be truncated well prior to 2300, it also is recommended that assessments of policy costs with respect to carbon take on a similar, longer time-period for analysis, regardless of uncertainty.**

**There Will Be Negative Trade Impacts of SCC Use on the U.S. and Emissions Leakage Problems**

The SCC values, as currently developed, expose U.S. businesses to a trade disadvantage, as other countries are not using similar carbon values in their policy regimes. Carbon allowances in the European Union and Australia for instance (with limited scope of coverage), trade far below the values that are currently being applied to regulations across all industries in the U.S. in policy analysis. Furthermore, China, a major importer of goods to the U.S., has no national carbon price. As the costs of additional regulation driven by SCC values ripple through the economy, businesses that produce carbon intensive goods will be subject to higher costs and become less competitive. Furthermore, the push to include these SCC valuations in regulatory analysis ignores the fact that U.S. emissions have declined while emissions from developing countries are likely to increase.

International competitiveness will be particularly important going forward with the ongoing development of GHG regulations for the electric sector. As the electric sector is carbon intensive and a large amount of goods produced in the U.S. have value added through electricity, additional costs associated with carbon regulation will translate in to higher domestic production costs. U.S. manufactured goods will be placed at an economic disadvantage to those produced abroad and production of these goods and corresponding GHG emissions will shift elsewhere. Emission leakage is well-established phenomenon that occurs between markets that place a different value on emissions or reductions. Leakage can also occur through regulation displacing domestic demand for fossil fuels, thus lowering the price and encouraging additional consumption in other sectors and in other countries. These types of shifts in emissions have not been considered to date in Regulatory Impact Analysis. **Without taking into account leakage, forecasting emission reductions in one sector and applying the Social Cost of Carbon will result in an overstating of net emission benefits. This area needs further exploration by the Interagency Working Group and OMB and firm guidance should be provided to address leakage.**

Social Cost of Carbon values can also be routinely updated exposing U.S. industry to never-ending policy uncertainty, which will play havoc on capital allocation. As many of the assumptions and linkages within the model are not well understood, a single variable could change the SCC values quite dramatically. This was recently evident as the updated SSC values were more than 50% larger than those previously published. **Thus, there needs to be a fixed period for peer-review and public comment to update the SCC values. Given capital allocation looks out over a long time horizon, a 10-year review cycle or longer is warranted.**

**Cost-Benefit Assessments Must Also Include the Economic Benefits of Lower Cost Energy**

Last, the calculation of the social cost of carbon values focuses almost entirely on the negative impacts associated with global climate change and ignores the benefits provided from the use of low-cost energy resources in lieu of more expensive albeit lower carbon alternatives. While the costs of abating emissions are generally picked up as part of a regulatory assessment of costs, the indirect benefits to economic growth, human health and well-being are not typically analyzed. **If an effort is being made to internalize all externalities within cost-benefit analysis, these types of benefits also need to be considered.**

**Final Recommendations**

The Social Cost of Carbon should not be used in further Regulatory Impact Analysis until outstanding issues regarding its development can be rectified. Among the major issues to be resolved are including public input and peer review of all model assumptions, ensuring calibration and agreement between models, use of narrower emission scenarios, using only projections of domestic damages, truncating model results to be consistent with evaluation of policy costs, providing for appropriate analysis of emission leakage and providing a consistent long-term period for updating of SCC values.

# Appendix F

## AEP 111(b) Comments Related to CCS

AEP
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Columbus, OH 43215-2373
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**Original by Mail**
**E-mail copy submitted to: a-and-r-docket@epa.qov**

May 8, 2014

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
ATTN: Docket ID No. EPA-HQ-OAR-2013-0495

Re: *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*
Docket ID No. EPA-HQ-OAR-2013-0495

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed standard of performance (NSPS) for greenhouse gas (GHG) emissions from new electric generating units (EGUs) under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

AEP is a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), the Electric Power Research Institute (EPRI), West Virginia Chamber of Commerce, and other industry organizations. Except as otherwise set forth herein, AEP incorporates by reference the comments submitted by these groups.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

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## VIII. Partial CCS is Not the BSER for Fossil Fuel-Fired Boilers and IGCC Units

### A. EPA's "best judgment" fails to demonstrate that CCS is the BSER

EPA's BSER determination considered four key factors: (i) technical feasibility, (ii) cost, (iii) emission reductions, and (iv) the promotion of technology development. EPA's evaluation of each of these factors and their "best judgment" of the BSER is flawed due to:

- a series of premature, inaccurate conclusions on the development, demonstration, and performance of advanced generation and CCS technologies;
- minimal consideration and an abrupt dismissal of widely-acknowledged barriers to CCS becoming a technically feasible and adequately demonstrated control option;
- an inadequate consideration of the lessons learned from actual projects and the conclusions reached by major public and private assessments of CCS development;
- an inconsistent use of criteria to perform the BSER analyses and to inform the Administrator's judgment within this proposal and compared to other rulemakings;
- an inadequate evaluation of the impacts to all sources within the source category; and
- use of underlying energy policy goals that do not allow for an objective evaluation of BSER in accordance with the Clean Air Act.

EPA uses the following analogy to describe its decision-making process for evaluating and determining the best system of emission reductions:

> "*the determination of what is 'best' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the 'best' sprinter in the 100-meter dash depends on only one criterion – speed – and therefore is relatively straightforward, while the question of who is the 'best' baseball player depends on a more complex weighing of several criteria and therefore requires a greater exercise of judgment*."[109]

While judgment is necessary, the agency has the tremendous responsibility to exercise that judgment based on a fair, objective, and holistic consideration of facts. EPA has not done this. Rather, by expansion of the aforementioned analogy, EPA's approach for exercising their judgment of the "best" baseball player (e.g. best system of emission reductions) is equivalent to relying on the conversations at a high school reunion where has-been baseball teammates reminisce using inflated statistics, tales of games that never happened, and vague recollections about walking to practice ten-miles, uphill and in the snow. This is precisely the type of logic the D.C. Circuit Court stated EPA should avoid – and that EPA quoted in the proposed rule – by noting that:

[109] 79 Fed. Reg. 1466. (January 8, 2014)

> "*...EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture*"[110]

With respect to carbon capture and storage, the scope of technical, financial, regulatory, and legal considerations is indeed "complex and necessarily requires an exercise of judgment." In the proposed rule, EPA describes, defends, and promotes the use of "major assessments" in applying judgment to their decision-making process on complex issues in other recent assessments by noting that:

> "*the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment...was to rely primarily upon the recent, major assessments...*"[111]

and:

> "*Primary reliance on the major scientific assessments provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community, rather than selecting the studies it would rely on.*"[112]

EPA clearly acknowledged the value of using major assessments to strongly inform its judgment on complex issues. Unfortunately, these values were not applied in the current EPA proposal as EPA ignores most of major assessments that are available regarding the challenges and opportunities for CCS and highly efficient electric generation technologies. Numerous public and private entities have completed (and continue to undertake) major assessments of CCS development. These are well documented and were, in part, summarized in AEP comments to EPA on the 2012 proposed 111(b) standards.[113] Of this large number of major assessments on CCS development, EPA narrowly considered only a very small fraction of the available information to inform its judgment. That fraction represents a limited literature review, minimal (if any) consideration of lessons learned from projects under development, a reliance on unrepresentative CCS experience from other industries, and the expected, but not demonstrated, performance of yet-to-be-constructed projects.

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[110] Id. 1479. (emphasis added)
[111] Id. 1438. (emphasis added)
[112] Id. 1456. (emphasis added)
[113] AEP Comments to EPA Regarding April 12, 2012 Proposed NSPS. p. 42 & Appendix D. Submitted June 25, 2012. Docket ID: EPA-HQ-OAR-2011-0660-10038

To illustrate this point, EPA used over 3,000 words[114] in the proposed rule to describe and defend their use of major assessments in prior rulemakings, but in evaluating the technical feasibility of CCS dedicated only 250 words[115] to their "literature review" and approximately 2,500 words[116] to their technical feasibility discussion of "capture, transportation, and storage technologies." As detailed in the following sections, EPA should significantly expand the scope of information considered in the BSER analysis to include the full range of available major assessments and other more relevant information. Doing so would be consistent with the approach EPA acknowledges is necessary for "complex" evaluations and would well position the agency to exercise their 'best judgment" in making a determination on CCS – a determination that will clearly indicate that CCS technologies (full and partial capture) are not the BSER for fossil fuel-fired generation and IGCC units.

### B. EPA has misinterpreted the realities and prospects of CCS development

For many years, strategies to reduce GHG emissions have been contemplated by policymakers, driven research and development, and influenced electric utility planning. Increasing attention by policymakers has led to a general acceptance that at some future point, a GHG reduction program would be implemented although the scope and timing of requirements were and remain unknown.

In planning for the possibility of GHG regulation, the electric utility community has considered **potential** emission control technologies and broader reduction strategies that **may become available**. In parallel, the U.S. Department of Energy, along with other public and private efforts, have correctly (and consistently) recognized that **potential** $CO_2$ emission reduction technologies, including CCS for fossil fuel-based electric generation processes, **must overcome significant development barriers if they are to have any chance of becoming** a technically feasible and commercially viable control option.

This recognition of the likelihood of $CO_2$ regulations and **speculation** on the potential availability, cost, and performance of CCS and other reduction strategies is helpful in attempting to forecast future needs, as well as to guide research and development efforts to meet those needs. However, this recognition **is not an affirmation or an endorsement** that CCS is

[114] 79 Fed. Reg. pp. 1438-1441. (Jan 8, 2014) Total Words in Section II. A. 3 "The Science Upon Which the Agency Relies".
[115] Id. p. 1471. Total Words in Section VII. E.1 "Literature"
[116] Id. pp. 1471-1474. Total Words in Section VII. E.2.a-c "Capture, Transportation, an d Storage Technologies"

currently or ever will be technically feasible or adequately demonstrated as a $CO_2$ emission control option for fossil fuel-based power generation.

AEP's own CCS experience highlights the fact that **CCS is far from being proven to be technically feasible or adequately demonstrated** at a commercial-scale due to an array of technical, financial, regulatory, legal, and practical barriers.[117] Numerous public and private programs have concluded the same.[118] EPA has failed even to begin to fully consider these various public and private studies. The EPA also fails to give even a cursory evaluation of the lessons learned from advanced generation and CCS projects that have actually operated, including AEP's Mountaineer Plant CCS program. As a result, EPA's BSER evaluation demonstrates a poor understanding of the state of CCS development, the development barriers that exist, and the prospects for successfully overcoming these barriers.

EPA ignores most of these development barriers and relies on an overly simplistic assessment to discredit their significance. EPA suggests that "the costs of $CO_2$ capture and compression represent the largest barriers to widespread commercialization of CCS."[119] While lowering capture and compression costs is a significant challenge, it is only one of many that impede the prospects of CCS becoming technically feasible, adequately demonstrated, and commercially viable. EPA's focus on capture costs grossly understates the breadth of barriers by downplaying the significant technical challenges that exist for *capture* systems and the equally significant technical, cost, and legal challenges for *transport* and *storage* systems.

These challenges cannot be addressed merely through desktop studies, research papers, engineering exercises, or technical specifications. It is critical that solutions to these challenges are developed and physically demonstrated with proven performance at a commercial-scale, while being exposed to the full gamut of commercial-scale power plant conditions. These solutions are a prerequisite to CCS becoming a technically feasible and adequately demonstrated $CO_2$ control option. EPA alludes to this process in the context of evaluating CCS for natural gas combustion turbines by noting that "*we cannot assume that the technology can be easily*

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[117] See Section IX.A for comments related to the AEP Mountaineer Plant CCS Program.
[118] See Section IX.B for examples of public and private efforts that determined that CCS has not yet been proven to be technically feasible or adequately demonstrated for fossil fuel-based power generation.
[119] 79 Fed. Reg. 1471. (January 8, 2014).

*transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC*."[120]

Although the U.S. leads the world in advancing the development of CCS related technologies, significant research, development, and demonstration work remains. For example, the CCPI was established to "accelerate the development of advanced coal technologies with carbon capture and storage at commercial-scale" through the demonstration of technologies that "make progress toward a target $CO_2$ capture efficiency of 90 percent" and that "make progress toward a capture and sequestration goal" that minimizes the resulting increased cost in electricity.[121] This program is indicative that CCS remains under development, not that it has been proven to be technically feasible and adequately demonstrated. Otherwise, the purpose of the CCPI would be to optimize mature technologies, and not to develop emerging or potential technologies. Round III of the CCPI selected six projects to "accelerate" and "make progress" the development of commercial-scale CCS. If these were six successfully completed projects, then a case could begin to be made that CCS is technically feasible, adequately demonstrated, and ready for commercial deployment. However, not a single one has commenced operation. Two are actively being constructed. The others are cancelled or must overcome major challenges to be able to begin construction. Indeed, most are no more developed than the conceptual work completed to initiate the project.

Successful development must be advanced in a systematic and step-wise manner. AEP began the process of advancing CCS to a commercial-scale. Even if the AEP commercial-scale CCS project had remained active, the project would not have been in service until at least 2015. AEP's expectation then was that commercial-scale CCS demonstrations were needed immediately *(e.g. 2015)*, so that in 2020, *at the earliest*, a reliable commercial-scale CCS process *might* be adequately demonstrated and ready for deployment. With the suspension of the AEP project and as other CCS projects are delayed or discontinued, the date for the commercial readiness of CCS technology continues to move farther into the future. Based on the current state of development, a reasonable estimate for CCS to be adequately demonstrated and commercially viable is at least ten years away – and this assumes that current financial and

[120] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[121] http://energy.gov/fe/clean-coal-power-initiative-round-iii. (Accessed January 29, 2014)

regulatory barriers are immediately removed. Without a clear path forward, the status of CCS development will remain, perhaps indefinitely, at least ten years away.

In summary, increased policy, research, and planning efforts focused on CCS development have advanced the knowledge of challenges and opportunities, but significant time and investment must be spent in order to address these development barriers. EPA has misinterpreted the purpose and outcome these efforts. The following comments demonstrate how far EPA missed the mark in their analysis and demonstrate that CCS is not the BSER.

**C. Technical feasibility is not the same as adequately demonstrated**

Varying degrees of technical feasibility can be determined through desktop calculations, laboratory studies, pilot-scale testing, large-scale demonstrations, or other methods. As such, a process that is technically feasible is not necessarily adequately demonstrated or commercially viable.[122] A determination of adequate demonstration cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial-scale on representative processes, allows for the optimization of systems integration and performance, and provides for cost-effective design options that can be safely and reliably operated. Absent this process, a technically feasible process remains just that – technically feasible and no more. Currently, CCS has yet to be adequately demonstrated at a commercial-scale on a coal-based electric generating unit.

**D. EPA's assessment of CCS is inconsistent with other EPA actions**

EPA's position on the feasibility and adequate demonstration of CCS in the proposed rule are in many ways contradictory to its assessment of the technology in the *PSD and Title V Permitting Guidance for Greenhouse Gases* document. Throughout the guidance document, EPA suggests that CCS be considered in a BACT analysis and that CCS will likely not apply because it is not technically feasible and/or because it is not cost-effective - both reasons also support the conclusion that CCS has not been adequately demonstrated. The following are excerpts from the guidance document in regards to CCS development:

- "*While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases*."[123]

[122] Technical feasibility, by itself, is insufficient to satisfy the BSER criteria of 111(a) of the Clean Air Act.
[123] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36.

- "*Based on these* [technical, cost, logistical, etc.] *considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.*"[124]

- "*EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2* [Technical Feasibility Analysis] *of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis* [Economic, Energy, and Environmental Impacts Analysis]*, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible.*"[125]

Based on these and other reasons, EPA indicates that CCS will likely not qualify as BACT. If the level of development is insufficient to generally apply CCS as BACT, it is also insufficient to support the determination that CCS is the BSER.

**E. EPA's technical feasibility evaluation fails to demonstrate that CCS is the BSER**

Technical feasibility is one of the key factors in the evaluation of the BSER. EPA's technical feasibility evaluation is comprised of a literature review and references to examples of CCS-related projects. Overall, EPA's assessment of technical feasibility is insufficient and relies on inaccurate conclusions that do not demonstrate that CCS is the BSER.

1. <u>EPA's literature review does not demonstrate that CCS is the BSER</u>

EPA determines that CCS is the BSER in part "through an extensive literature record."[126] Despite the broad number of published major assessments, reports, and research papers on CCS development issues, the "extensive literature record" that EPA evaluated consisted of *only three* resources: (i) the 2010 Interagency Task Force on CCS Report, (ii) a 2009 Pacific Northwest National Laboratory study of the commercial availability of CCS technologies, and (iii) a 2011 DOE/NETL report titled "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture." If taken in proper context and thoroughly read, none of these resources conclude commercial-scale CCS has been sufficiently proven to be technically feasible or adequately demonstrated for coal-based generating units. In contrast, these reports identify many

[124] Id.
[125] Id. at. pp 42-43.
[126] 79 Fed. Reg. 1471. (January 8, 2014).

of the technical, financial, regulatory, and integration barriers to broader CCS development and acknowledge that it will take time and additional research and development to address these issues. It is also noteworthy that *none* of the reports considers the lessons learned and experiences of actual projects such as the AEP Mountaineer CCS validation-scale plant, or the CCS projects under development for coal-based electric generation that EPA references in the proposed rule. A review of each report follows.

*a. Review of 2010 Interagency Task Force on CCS Report*

EPA misinterprets the findings of President Obama's Interagency Task Force on Carbon Capture and Storage ("Task Force") in their evaluation of CCS at the BSER. The charge of the report alone does not support the determination that CCS has been proven to be technically feasibility or adequately demonstrated for fossil fuel-based generating units. As EPA points out:

> "*The Task Force was charged to propose a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016.*"[127]

EPA summarizes the report as follows:

> "*The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current cost of CCS relative to other technologies, there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions.*"[128]

Describing these barriers as not being insurmountable is one thing, but acknowledging the time and resources required to overcome these barriers is another. For example, the barriers for mankind to travel to Mars are not insurmountable, but significant technical and financial challenges must first be addressed. EPA is either naive about or has chosen to ignore the magnitude of CCS development challenges. The Task Force was neither. As noted above, the very charge of the Task Force was to propose a plan to overcome these barriers within 10 years!

What the EPA does not point out is that the Task Force also found that "*barriers hamper near-term and long-term demonstration and deployment of CCS technology.*"[129] In essence, an ambitious near-term research, development, and demonstration program would need to be implemented in order to overcome barriers to the commercialization of CCS. To date, such

[127] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[128] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[129] Report of the Interagency Task Force on Carbon Capture and Storage, p. 14 (Aug 2010).

programs have yet to produce a single operating commercial-scale demonstration project at a coal-based generating unit and are not on pace to achieve the five to ten projects by 2016 that the Task Force recommended for overcoming barriers by 2020.

Finally, it is noteworthy that Task Force alludes to the deployment of CCS projects as being "first-of-a-kind technology", which accurately describes its state of development. This point seems to be lost by EPA in their cost evaluation of CCS as discussed in detail later.

*b.* *Review of Pacific Northwest National Laboratory Report: An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*

EPA also relies upon on a 2009 report from the Pacific Northwest National Laboratory ("PNNL") to evaluate the availability of CCS. Specifically, EPA states:

> "*(PNNL) recently prepared a study*" and that the "*study concluded, in general, CCS is technically viable today and that key component technologies of complete CCS system have been deployed at scales large enough to meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants*."[130]

The "recently prepared" study was completed over four years ago. Many major assessments of CCS development have been completed since that would provide more updated perspectives. Terms that EPA relies upon such as "in general" and "meaningfully inform discussions" are far from being equivalent to technically feasible and adequately demonstrated at a commercial scale on a coal-based electric generating unit. In addition, the report does not suggest that CCS has been proven to be technically feasible and adequately demonstrated for fossil-fuel based generating units, rather the study acknowledges that:

> "*The limited, early large scale commercial adoption of complete, end-to-end CCS systems which has taken place to date has occurred outside the electric power sector*."[131]

and that

> "*there is truth to the often heard assertion that CCS has never been demonstrated at the scale of a large commercial power plant*."[132]

Among the greatest and widely recognized barriers to CCS development for fossil-fuel based generation units are those technical and financial challenges associated with integrating

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[130] 79 Fed. Reg. 1471. (January 8, 2014). (emphasis added)
[131] "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. Pacific Northwest National Laboratory. Dooley, et.al. PNNL-18520. June 2009. p. 4. (emphasis added)
[132] Id. p. 7. (emphasis added)

various components of CCS technology with power plant operations. The study does not attempt to evaluate the magnitude of these integration challenges. To the contrary, the study notes that:

> "[o]*ne explicit goal of this paper is to* *examine – in a disaggregated manner – the status of CCS technologies and their component systems*."[133]

The PNNL study caveats its results by referencing how much work remains for CCS development. The following qualifiers do not support EPA's determination that CCS the BSER:

> "*The fact that.....CCS systems exist and the needed system components of a CCS system are commercially available does not undercut the rationale for* *a vigorous ongoing research, development and demonstration program* *focused on improving CCS technologies and demonstrating them in various combinations of technological, geographical, and geologic applications and settings.*"[134]

and

> "*The deployment of CCS.....will need a more clearly defined regulatory framework*" *for issues such as "property and mineral rights, and settlement of liability concerns related to the long-term storage of* $CO_2$."[135]

*c. Review of 2011 DOE/NETL Report: "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture"*

The report contains no information on the lesson learned and experience of actual projects, but rather relies upon incomplete, vendor-supplied data of technologies that have never been constructed or integrated. A strong critique of this report is provided in the comments below on EPA cost analysis. In short, these comments demonstrate that the report is insufficient for providing reliable cost assessments that can meaningfully assess the state of CCS technology and that the report is insufficient for determining whether the CCS has been proven to be technically feasible and adequately demonstrated at a commercial scale.

2. The project examples identified by EPA do not demonstrate that CCS is technically feasible or adequately demonstrated

A determination that CCS is technically feasible and has been adequately demonstrated cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial-scale on representative processes, allows for the optimization of systems integration and performance, and provides for cost-effective design

[133] Id. p. 4. (emphasis added)
[134] Id. p. 2. (emphasis added)
[135] Id. p. 3. (emphasis added)

options that can be safely and reliably operated. EPA correctly alludes to these steps as being necessary for determining the technical feasibility of CCS as follows:

> "*The EPA considered whether NGCC with CCS could be identified as the BSER...and we decided that it could not be. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units.*"[136]

and

> "*This cyclical operation, combined with the already low concentration of $CO_2$ in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical* [unit]."[137]

While EPA makes these statements in the context of its consideration of CCS for natural gas combustion turbines, the concerns are equally applicable to fossil fuel EGUs and IGCC units:

- where a much greater volume of $CO_2$ must be captured, transported, and sequestered;
- where CCS has not been demonstrated at a commercial scale;
- where it "*cannot* [be] *assume*[d] *that the technology can be easily transferred*";
- where there have been no "*larger scale demonstration projects on units operating like a typical* [unit]; and
- where "*there is insufficient information to make a determination regarding the technical feasibility of implementing CCS.*"

In a flawed attempt to prove that these concerns have been addressed for coal-based generating units, EPA references 25 examples of CCS and CCS-related efforts in the proposed rule. A detailed analysis of each is provided Appendix A. None of these examples, independently or collectively, is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units. A summary of this analysis of the project examples that EPA relies upon in the proposed rule found that:

- **Only** 6 of the 25 EPA examples represent commercial-scale CCS integrated with coal-based generating units. Of these six examples:
  - **None** are operational
  - **All** represent first-of-a-kind $CO_2$ capture technologies on a coal-based generating unit
  - 4 of the 6 examples represent first-of-a-kind combustion technologies
  - Only 2 of the 6 are undergoing active construction

[136] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[137] Id. (emphasis added)

- The 4 remaining projects are "planned" to startup between 2016 and 2019
- Prospects for the 4 remaining projects are questionable due to financial challenges and a lack of regulatory approvals
- **None** of the 6 examples is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units.

▪ 8 of the 25 EPA examples are of carbon capture efforts from fossil fuel-based generating units that are **insufficient** in size, among other factors, to assess commercial-scale CCS performance or viability
  - 2 of the 8 examples are validation-scale CCS projects on coal-based generating units that are proof-of-concept projects, **not commercial-scale demonstration efforts**
  - 4 of the 8 examples capture $CO_2$ from slip-streams of coal-based and natural gas combustion turbine units for food and soda ash industries; **these are not commercial-scale demonstration efforts and lack any geologic storage component**
  - 2 of the 8 examples are for "planned" projects that have not been officially announced

▪ One of the 25 EPA examples represents a validation-scale oxy-combustion project (10MWe) that is **not a commercial-scale demonstration and lacks geologic storage**

▪ 8 of the 25 EPA examples are $CO_2$ sequestration efforts. Of these eight examples:
  - **None** are integrated with a fossil fuel-fired electric generating unit
  - Only 5 of the 8 are active processes
  - 2 of the 8 are "potential projects", while one of the examples discontinued operation
  - **None** of the 8 examples is sufficient to determine that commercial-scale CCS is technically feasible or adequately demonstrated for coal-based generating units.

▪ 2 of the 25 EPA examples are databases that summarize CCS development
  - GCCSI Database: Only 2 of the 60 power generation CCS efforts are "active" projects, the balance are "planned." These 2 projects offer no new information as they are specifically identified in the proposed rule and accounted for above.
  - DOE CCUS database: It does not list any noteworthy CCS efforts beyond those specifically identified in the proposed rule and accounted for above. In fact, much of the information appears to be very dated and inaccurate.

In fact, only two of the 25 EPA examples are actively undergoing construction and represent commercial-scale CCS projects integrated with coal-based generation units. While these two efforts will advance the knowledge of CCS opportunities and challenges, they are far from being sufficient to make a regulatory determination that CCS is technically feasible and adequately demonstrated because their operation and performance capabilities are to be determined. In addition, one unit is a first-of-a-kind (FOAK) IGCC project, while both projects will utilize FOAK CCS technologies. It is to be determined whether the cost-escalations experienced by both projects, as well as the technical risks and performance uncertainties that are inherent with any FOAK process can be adequately addressed to make the next generation of technologies viable for potential developers. The experience, positive or negative, of these two efforts, alone, will be insufficient to determine if the technology is feasible or adequately demonstrated as suggested by several major assessments. For example, EPA references the Final Report of the Interagency Task Force on CCS by noting that:

> "*The Task Force was charged with proposing a plan to overcome the barriers to widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016*" [138]

The two CCS projects referenced by EPA that are actively being constructed are likely to be the only two demonstration projects online by 2016. This amount falls short of the 5 to 10 projects identified by the Task Force as necessary to overcome significant development barriers – barriers the prohibit any determination that commercial-scale CCS for coal-based generating units is technically feasible and adequately demonstrated.

Finally, EPA's premature reliance on undeveloped or unrelated CCS and CCS-related examples is inconsistent with its evaluation of one project that was under development when the proposed rule was signed – the Wolverine Power Cooperative coal-based power plant in Michigan. In regards to the Wolverine project, the proposed rule notes that:

- "*EPA is not proposing standards today for one conventional coal-fired EGU project which, based on current information, appears to be the only such project under development that has an active air permit and that has not already commenced construction*"[139] (emphasis added)
- "*If the EPA observes that the project is truly proceeding, it may propose a...*[NSPS]*...specifically for that source*[140]" (emphasis added)
- "*EPA has not formulated a view as to the project's status in the development process*"[141] (emphasis added)

At the time of the proposed rule, the Wolverine Project had obtained an air permit, was actively seeking financing, but had not started construction. Based on this information EPA was unable to "formulate a view as to the project's status" and was unable to determine if "the project is truly proceeding." Yet, in many regards, the Wolverine Project as described was much farther

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[138] 79 Fed. Reg. 1471 (January 8, 2014)
[139] 79 Fed. Reg. 1434 (January 8, 2014)
[140] 79 Fed. Reg. 1434 (January 8, 2014)
[141] 79 Fed. Reg. 1461 (January 8, 2014)

along then many of the CCS examples that EPA relies upon, which **do not** have an air permit or other regulatory approvals, face **more significant** financial challenges, and **have not** started construction (i.e. the Hydrogen Electric California project). Ironically, EPA was able to overlook these more substantial development barriers to not only "formulate a view" that these CCS projects are "truly proceeding," but also EPA was able to extend this "view" to conclude that these projects are proof that commercial-scale CCS is technically feasible and is being adequately demonstrated. EPA's view is simply incorrect. EPA is also incorrect in asserting that

> "*the Wolverine project appears to be the only fossil fuel-fired boiler or IGCC EGU project presently under development that may be capable of 'commencing construction' for NSPS purposes in the very near future and, as currently designed, could not meet the 1,100 lb $CO_2$/MWh standard*"[142]

There is no basis to determine that *any* of the coal-based CCS projects identified by EPA could meet the proposed NSPS. These projects are not regulated to achieve a specific $CO_2$ limit and, where applicable, are only required to demonstrate the performance of the CCS system for a specified period. Thus, significant uncertainty exists as to whether the proposed limit will ever be achieved over the short- or long-term operation of these projects, to the extent they are even constructed.

3. EPA Has Misinterpreted the Experiences of Other Industries in the Evaluation of Technical Feasibility of CCS for Fossil Generation Sources

EPA incorrectly uses the experience of other industries to support their evaluation of CCS for fossil fuel-fired electric generating sources. For example, EPA notes that "*the capture of $CO_2$ from industrial gas streams has occurred since the 1930's using a variety of approaches*."[143] For EPA to suggest that capture technologies should be readily transferable to coal-based electric generating units because of a long history of use in other industries ignores the multitude of technical, process design, and operational differences between the "industrial gas streams" referenced and a coal-based power plant. It also ignores the significant difference in the quantities and end use of the captured $CO_2$, which will be orders of magnitude greater from coal-based generation units than that for most "industrial gas streams." In addition, the likely end-use for coal-based $CO_2$ will be geologic sequestration or enhanced oil recovery

[142] 79 Fed. Reg. 1461 (January 8, 2014). (emphasis added)
[143] 79 Fed. Reg. 1471. (January 8, 2014).

processes, which pose much different challenges than capture from industrial gas streams "to produce food and chemical-grade $CO_2$."[144] The agency also notes that pre-combustion, post-combustion, and oxy-combustion capture systems are technically feasible.[145] However, *none* of these capture systems has been adequately demonstrated at a coal-based power plant on a commercial-scale as either an independent process or, more importantly, as an integrated process with a $CO_2$ utilization or geologic storage system.

### F. EPA's cost analysis fails to demonstrate that CCS is the BSER

Cost related issues are another key component of the evaluation of the BSER. EPA has a long history of demanding comprehensive cost evaluations as part of the BACT analyses process for much more established emission control technologies. It would only be reasonable to expect that EPA would, at the very least, demand the same of itself in evaluating an emerging technology such as CCS where first-of-a-kind commercial projects have yet to occur and where the inherent scope and magnitude of considerations and uncertainties at issue makes developing useful cost estimates tenuous even when considering the best of all available information. Instead, EPA's cost analysis is flawed throughout and produces highly suspect and unreliable conclusions due to:

- an incorrect assessment of the development status of CCS, which results in using cost estimates for yet-to-be realized more mature $n^{th}$-of-a-kind ("NOAK") type technologies, rather than initial first-of-a-kind ("FOAK") technologies;
- a narrow reliance on two reports that are based on dated vendor supplied conceptual designs for CCS and IGCC technologies that have **never** been constructed or proven;
- a failure to consider **any** of the costs and lessons learned from actual CCS related projects that have been constructed or that are actively being developed; and
- a failure to consider more recent and relevant studies of the cost of advanced coal-based generation and CCS technologies.

The result of these fallacies is a reliance by EPA on cost estimates that are "*somewhere between FOAK and NOAK*" despite the agency alluding to CCS in the same paragraph as being an "*emerging technology*", "*not yet fully mature*", and "*not yet...serially deployed in a commercial context*".[146] The use by EPA of CCS costs that are premised on the conjecture of NOAK projects does not remotely provide reliable, accurate estimates, is irrelevant for use in

[144] 79 Fed. Reg. 1471. (January 8, 2014).
[145] Id. 1472.
[146] 79 Fed. Reg. 1476. (January 8, 2014)

preforming any objective analysis of new generation options, and has the appearance of being nothing more than weak attempt to justify a preconceived BSER outcome that could not otherwise be validated through the use of more reasonable and accurate information.

1. EPA's cost analysis is flawed due to an incorrect assumption that CCS development has advanced beyond first-of-a-kind technologies

Costs along the development timeline for any technology are dependent on the starting point of FOAK projects, the scope of cost reduction opportunities, and the rate at which these opportunities are realized in future projects. At present, FOAK projects that integrate CCS and coal-based generation technologies are only being to be developed. Significant uncertainties remain regarding the costs of known and unknown variables and with respect to the scope and prospects of opportunities to lower these costs. As such, reliable demonstrated FOAK costs for CCS and advanced coal generation technologies, such as IGCC, *are not available.* The current state of CCS development has been widely recognized to be at the FOAK deployment phase, including by the Interagency Task Force on CCS.[147] This is ignored by EPA, which notes that:

> "*For an emerging technology like CCS, costs can be estimated for a 'first-of-a-kind' (FOAK) plant or an 'n^th-of-a-kind' (NOAK) plant, the later of which has lower costs due to the 'learning by doing' and risk reduction benefits that will result from serial deployments as well as from continuing research, development, and demonstration projects.*"[148]

EPA's assessment is incorrect. Where CCS currently stands on that timeline today makes estimating cost for any projects beyond FOAK technologies premature and nothing more than fanciful speculation. The current state of CCS development has not moved beyond FOAK projects, which are only beginning to be constructed and where cost estimates have varied widely and continue to escalate. Reliable baseline costs, performance information, and lessons learned from FOAK CCS projects are required before the true scope of cost implications can be understood. Because CCS development issues are far from being one-sized-fits-all, the completion of multiple commercial-scale projects on coal-based generating units is critical for informing for any meaningful cost estimate of future NOAK CCS processes. Likewise, EPA's requisite "learning by doing" is premature because the only relevant commercial-scale "doing" that can be referenced is the construction of two FOAK CCS projects and ambitious conceptual designs of projects that may never occur. Further, to the extent any "doing" has occurred, such

[147] Report of the Interagency Task Force on Carbon Capture and Storage. (Aug 2010). p. 8.
[148] 79 Fed. Reg. 1476. (January 8, 2014).

as the AEP Mountaineer Plant CCS Validation Project, the cost, performance, and other lessons learned from these efforts are not considered in the DOE/NETL reports that EPA relies upon.

2. EPA's cost analysis is flawed due to a narrow review of available information and a failure to consider the cost of actual projects

EPA's cost analysis relies on *only two* DOE/NETL reports that are based on conceptual designs for technologies that, at least in the case IGCC and CCS, have never been constructed. In fact, much of the cost analysis language contained in the preamble is verbatim from these reports, albeit without appropriate references.

These reports identify some of the cost drivers for CCS and advanced coal technologies, but are insufficient for providing reliable cost assessments for use in regulatory development or in planning future projects. For example:

- EPA uses CCS cost estimates that represent more mature, NOAK type technologies, even though FOAK technologies have **not yet** been demonstrated. The result is an overly optimistic and incorrect conclusion that CCS costs will be lower that what otherwise could be reasonably estimated.

- EPA uses cost estimates that range from -15% to +30%. Such a wide range is indicative of a FOAK type technologies, but **not** technologies that have advanced beyond FOAK.[149]

- EPA uses cost estimates that evaluate generation and CCS technologies that only use bituminous coals. **No consideration** was given to the use of lower rank coals.

- The cost estimates are premised on vendor supplied information for 12 different plant configurations that represents six IGCC designs, 2 subcritical pulverized coal designs, 2 supercritical pulverized coal designs, 1 synthetic natural gas ("SNG") production plant, and 1 repowering of an existing NGCC plant with SNG. Of note, **neither** the IGCC unit designs, nor the SNG-related process have ever been constructed. Also, **no consideration** was given to ultra-supercritical pulverized coal configurations.[150]

- The cost estimates for the above mentioned 12 units assumed that carbon capture was achieved through the use of the Fluor Econamine FG Plus capture process for pulverized coal unit and the use of a water-shift reactor and a two-stage Selexol process for IGCC units. **Neither** carbon capture process has been ever been demonstrated on a coal based generating unit at any level, and certainly not at a commercial-scale.[151]

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[149] 79 Fed. Reg. 1476. (January 8, 2014).
[150] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010). p. 1
[151] Id. p.4

- Dated cost estimates were derived from modeling conducted in 2009 and 2010.[152]
- The cost estimates for geologic storage systems are overly simplistic generalizations that are not representative of the high costs associated with the characterization, development, and operation of injection and monitoring wells. Due to the age of the study, no estimates are included for the anticipated high costs for complying with the EPA Class VI Underground Injection Control ("UIC") program. In fact, the UIC program had not been finalized when the study was completed.
- EPA references a number of CCS related projects to support their BSER analysis and acknowledges that "*the lessons learned from design, construction, and operation of those projects...*["*currently under development*"]*...will help lower cost for future gasification facilities implementing CCS*."[153] Despite the value of these "lessons learned," the DOE reports that EPA relies upon give **no consideration** of the very projects that EPA utilizes to justify their BSER determination.

Background on the cost estimating methodology employed in these two NETL studies that EPA relies upon is described in a separate NETL report, which characterizes the approach as "techno-economic studies." Specifically, NETL notes the following with respect to the design of these studies and the value of the results:

> "*Conceptual cost estimates used in techno-economic studies are typically factored from previous estimation data and are not accurate as actual detailed estimates*."
>
> and
>
> "*Most techno-economic studies completed by NETL feature cost estimates carrying an accuracy of -15 percent/+30 percent, consistent with a "feasibility study"...level of design engineering applied to the various cases... The reader is cautioned that the values generated for many techno-economic studies have been developed for the specific purpose of comparing relative cost of differing technologies. They are not intended to represent a definitive point cost nor are they generally FOAK values*."[154]

The cost information in these two reports does represent the costs that are being estimated and incurred by the active CCS and advanced coal-based generation projects, which are more refined and representative. However, caution should be noted as well in interpreting and applying these actual project costs as the estimates vary widely and continue to escalate, and the information may not be applicable for projecting the cost of future projects.

[152] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010). (e.g. p. 125: Oct 8, 2009; p. 156: Jan 14, 2010)
[153] 79 Fed. Reg. 1476. (January 8, 2014).
[154] "Technology Learning Curve (FOAK to NOAK)" (Aug 2013). NETL p. 5. (emphasis added)

Given the uncertainty with estimating FOAK CCS project, the ability to quantify potential cost reductions for future CCS projects is tenuous at best. A recent report by the Congressional Research Services addresses this issue by noting:

> "*The challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States.*"[155]

> and

> "[C]*osts for technologies tend to peak for projects in the demonstration phase of development... What the cost curve will look like, namely, how fast costs will decline and over what time period, is an open question and will likely depend on if and how quickly CCS technology is deployed on new and existing power plants*."[156]

In fact, development costd may actually *increase* as the technologies mature. For example, in the 2012 proposed GHG NSPS EPA referenced one study by Rubin, et. al that evaluated this issue.[157] That study found:

> "*there is currently little empirical data to support the assumptions and models used to calculate future $CO_2$ capture costs for power plants*," and that "*there are no easy or reliable methods...to quantify the magnitude of potential cost increases commonly observed during early commercialization.*"

> and in regards to the methodology of their analysis, the study states:

> "[o]*ne drawback of this approach is that it does not explicitly include potential cost increases that may arise when building or combining components that have not yet been proven for the application and/or scale assumed.* [In addition] *a study of this nature...has other important limitations that must be recognized. For one, the concept of a constant learning rate... often...is an over-simplification of actual cost trends for large-scale technologies.*"[158]

Therefore, EPA should factor into their analysis that development costs may actually increase, and increase dramatically as new information is discovered. NETL has recognized this very issue in noting that:

> "*...cost reductions do not always begin with the second plant... In some cases, the FOAK plant experience also leads to unpredictable problems and the realization that more components or more expensive components are needed, resulting in the next installation*

[155] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service. p. 6
[156] Id. p. 11
[157] 77 Fed. Reg. 22416. (April 13, 2012)
[158] Rubin, E.S., et. al. "Use of experience curves to estimate the future cost of power plants with $CO_2$ capture." International Journal of Greenhouse Gas Control I, pp. 189-196 (2007) (emphasis added).

*again being fundamentally different. In these cases, the costs may actually increase for the first few installations."*[159]

A recent Congressional Research Services report reaffirms this conclusion by noting that the knowledge gained though research, demonstration, and initial operating experience sometimes results in *increased* costs during the development period, and the magnitude and rate of development is not a one-size-fits-all trend.[160]

3. <u>The experience of recent projects and findings of major studies demonstrate that EPA's cost analysis is flawed and that CCS is not the BSER</u>

The recent experience of CCS and advanced coal-based generation projects underscores the difficulty of developing reliable costs FOAK technologies, yet alone the significant uncertainty and challenge of being able to assess the cost of future FOAK and especially NOAK projects with any degree of accuracy. This difficulty is highlighted by the projects that EPA relies upon in the proposed rule where there is a wide disparity in costs and where each project is experiencing significant cost escalations. The risk of relying on cost estimates for FOAK CCS projects was noted by an executive from SaskPower in regards to their Boundary Dam CCS project that is currently being constructed:

Interview Question: "*Stepping back, what does your project mean for the entire race to commercialize CCS?*"

Answer: "*Well, the significance for me is, if you look at what people are guessing as the cost of capturing carbon, that is all it is, is a guess. There is so much swing in estimating what the capture costs* [are], *that it makes the numbers senseless.*"
Mike Monea – SaskPower President, CCS Initiatives[161]

A number of recent assessments have concluded that CCS for fossil fuel-fired electric generation currently is and will remain at the FOAK level of development for many years. These conclusions do not support EPA's use of cost estimates that the agency presumes represent technologies that have matured beyond FOAK projects. For example, the 2010 DOE/NETL CCS Roadmap noted that the DOE RD&D effort "*involves pursuing advanced CCS technology...so that full-scale demonstrations can <u>begin by 2020</u>*" in order to "*enable broader commercial deployment of CCS to <u>begin by 2030</u>.*" The report also notes that "*advanced*

[159] "Technology Learning Curve (FOAK to NOAK)" (August 2013). NETL p. 2.
[160] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700, at pp. 6, 9 (September 30, 2013).
[161] SNL Energy interview with Monea, M. (May 31, 2013). www.snl.com/InteractiveX/article.aspx?ID=17840071

*technologies developed in the CCS RD&D effort need to be tested at full scale...before they are ready for commercial deployment.*"[162] In addition, the DOE/NETL "Carbon Capture" website discusses the following in the very first paragraph:

> "*first-generation $CO_2$ capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale, require approximately one-third of the plant's steam and power to operate, and are cost prohibitive.*"[163]

The DOE CCS Roadmap also estimates that commercial-scale CCS will add 80% to the cost of electricity for a new pulverized coal unit and 35% to the cost of a new IGCC unit and highlights the infancy of the technology as a potential emissions control option for coal-based generation.[164] In addition, the DOE/NETL website indicates that one of their CCS research and development goals is to develop "*2nd-Generation technologies that are ready for demonstration in the 2020-2025 timeframe (with commercial deployment beginning in 2025).*"[165] It is clear from this information that cost estimates for future CCS projects are far from being able to accurately represent NOAK processes.

A separate NETL report notes "*the definition of the NOAK plant is somewhat arbitrary as well, although it is often taken as the fifth or higher plant.*" Given that initial commercial-scale CCS projects on coal-based electric generating units have not yet been demonstrated and only two projects are actively being constructed, the technology is many years from even approaching a fifth generation plant that could be characterized as a NOAK technology. NETL also cautions how projects are characterized in the development process by noting that:

> "*Care is needed in defining FOAK and NOAK. For major new facilities, the number of installations is largely applicable to a specific supplier's technology. For example, although the gasification technologies are similar, it is unlikely that one vendor will share sufficient experience that benefit rivals such that learning will occur.... Projects that use $N^{th}$ plant technology in some of the plant, but that use large, new, critical subsystems elsewhere should also be considered FOAK.*"[166]

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162 DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap, pp. 10-11 (Dec. 2010). (emphasis added)
163 www.netl.doe.gov/research/coal/carbon-capture (Accessed Mar. 3, 2014) (emphasis added)
164 DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec. 2010). p. 10
165 www.netl.doe.gov/research/coal/carbon-capture/goals-targets (Accessed March 3, 2014)
166 "Technology Learning Curve (FOAK to NOAK)" (Aug 2013). NETL p. 2.

In other words, the minimal commercial-scale CCS projects that are actively being developed may be sufficiently unique as to limit the overall progress of the technology beyond FOAK applications.

For any individual project, the cost estimate will change throughout the phases of development: (i) conceptual design; (ii) front-end engineering & design (FEED); (iii) detailed design; (iv) construction; (v) startup & commission; (vi) operational. As technologies mature, the cost differential between conceptual design and operational cost will become less. This cost differential for an individual project can vary significantly across the development cycle, as well as from project to project that employ FOAK technologies. The tables that follow summarize costs of actual CCS projects that have been or that currently are being developed to demonstrate this variability and to highlight the fact that CCS technology is far from advancing beyond a FOAK level of development.

**Summary of Escalating Cost Estimates at Critical Project Milestones for Ongoing Commercial-Scale CCS Demonstrations**

| Company | Unit | Output | Conceptual Design | FEED[167] | Detailed Design | Construction | Startup & Commissioning | Type |
|---|---|---|---|---|---|---|---|---|
| Kemper (Southern Co) | IGCC with CCS/EOR | 582 MWn | $2.4 billion[168] | --- | --- | $5.5 billion[169] | --- | FOAK: IGCC Design<br>FOAK: Integrated CCS |
| Tx Clean Energy Project (Summit) | IGCC/Polygen with CCS/EOR | 400 MWg<br>130-212 MWn | $1.73 billion[170] | $3.8 billion | --- | --- | --- | FOAK: IGCC/Polygen<br>FOAK: Integrated CCS[171] |
| Hydrogen Energy California | IGCC/Polygen with CCS/EOR | 405-431 MWg<br>151-266 MWn[172] | $4 billion[173] | --- | --- | --- | --- | FOAK: IGCC/Polygen<br>FOAK: Integrated CCS |
| Boundary Dam[174] (SaskPower) | PC (rebuild) with CCS/EOR | 160 MWg<br>110 MWn | $1.24 billion ($354 million for rebuild) | --- | --- | $1.355 billion[175] | --- | FOAK: Integrated CCS |
| W.A. Parish (NRG Energy) | PC (retrofit) with CCS/EOR | Capture from 250MWe[176] | $338 million[177] | $775 million | --- | --- | --- | FOAK: Integrated CCS |
| FutureGen 2.0[178] | PC (retrofit) with CCS | 168 MWg | $1.3 billion ($740 million for rebuild)[179] | $1.77 billion | --- | --- | --- | FOAK: Oxy-combustion PC<br>FOAK: Integrated CCS |

167 Unless noted, all FEED costs from: Ackiewicz, M. (January 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
168 Mississippi Public Service Commission Order. RE: CPCN Petition from Mississippi Power Company. Docket 2009-UA-14. April 30, 2010. p. 4
169 "Southern Co delays advanced coal plant to 2015 amid rising costs." (April 29, 2014). O'Grady. E. Reuters.
170 76 Fed. Reg. 60478 (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.
171 www.texascleanenergyproject.com/ (accesses Feb 24, 2014) [FOAK Reference]
172 HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf
173 Ackiewicz, M. (January 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
174 Data from unless noted: Boundary Dam CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/boundary_dam.html (accessed February 24, 2014)
175 www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html
176 Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p. 3
177 W.A. Parish CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/wa_parish.html (accessed February 24, 2014)
178 Data from unless noted: 79 Fed. Reg 3578. (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project
179 "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. R43028. p.1

## Summary of Escalating Cost Estimates at Critical Project Milestones for Other Utility Projects

| Company | Unit | Output | Conceptual Design | FEED | Detailed Design | Construction | Startup & Commissioning | Type |
|---|---|---|---|---|---|---|---|---|
| AEP John W. Turk[180] | Ultrasupercritical Pulverized Coal No CCS | 600 MWg | $1.3 billion[181] | --- | --- | --- | $1.8 billion | First USC coal generating unit in the United States |
| AEP Mountaineer[182] (validation-scale) No longer in-service | Existing PC (1300 MW plant) CCS validation-scale project | Capture from 25MWe slip-stream | $100 million | --- | --- | --- | $100 million | First integrated CCS project on a coal-based generating unit in the world |
| AEP Mountaineer[183] (commercial-scale) Project Cancelled | Existing PC (1300 MW plant) CCS commercial-scale project | Capture from 235MWe slip-stream | $668 million | $1 billion (plus $300 million cost risk for UIC compliance) | --- | --- | --- | FOAK: Integrated CCS |
| Tenaska Trailblazer[184] Project Cancelled | PC with CCS/EOR | 765 MWg 600 MWn | $2.5 billion[185] | $3.5 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |
| Edwardsport (Duke Energy) | IGCC No CCS | 618 MWg[186] | $2 billion[187] | --- | --- | --- | $3.5 billion[188] | FOAK: IGCC Design |
| Tenaska Taylorville[189] Project Cancelled | IGCC with CCS | 716 MWg 602 MWn | $2 billion[190] | $3.5 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |
| FutureGen1.0[191] Project Cancelled | IGCC with CCS | 275 MW | $950 million | $1.8 billion | --- | --- | --- | FOAK: IGCC Design FOAK: Integrated CCS |

180 Unless noted data for Turk Plant from: www.aep.com/newsroom/newsreleases/?id=1795 (December 20, 2012)
181 www.aep.com/newsroom/newsreleases/Default.aspx?id=1367
182 Data for Mountaineer Validation-Scale project from: "AEP CCS Program Overview" Spitznogle. (March 11, 2011) AEP. www.sseb.org/wp-content/uploads/2010/05/Gary-Spitznogle.pdf
183 Data for Mountaineer Commercial Scale project from: www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report
184 Unless noted, Trailblazer data from: "Update on Tenaska Trailblazer Energy Center" http://cctft.org/wp-content/uploads/2013/02/Jeff-James-Tenaska.pdf
185 www.power-eng.com/articles/2009/01/tenaskas-coal-fired-igcc-plant-moves-forward.html
186 www.duke-energy.com/power-plants/coal-fired/edwardsport.asp
187 Q1 2008 Duke Energy Corporation Earnings Conference Call. Conference Call Transcript. (May 2, 2008) p. 6
188 Thompson, G. Direct Testimony to Indiana Utility Regulatory Commission. Filed December 23, 2013. Exhibit B-1.
189 Unless noted, Taylorville data from: "Taylorville Energy Facility Cost Report" (February 26, 2010). Worley Parsons. www.icc.illinois.gov/electricity/tenaska.aspx
190 www.power-eng.com/articles/2007/06/tenaska-obtains-illinois-clean-coal-plant-permit.html
191 Data for FutureGen 1.0 is from: "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. p.11

The cost escalation and $/kW estimates for the aforementioned projects are summarized below:

| Project | Design | CCS | Status | Conceptual Cost Estimate ($ billion) | Most Recent Cost Estimate ($ billion) | Project Cost Escalation (%) |
|---|---|---|---|---|---|---|
| Kemper | IGCC | CCS | active | 2.4 | 5.5 | **129%** |
| Texas Clean Energy Project | IGCC/poly | CCS | active | 1.73 | 3.8 | **120%** |
| Hydrogen Energy California | IGCC/poly | CCS | active | 4 | --- | **---** |
| FutureGen 2.0 | IGCC | CCS | active | 1.3 | 1.77 | **36%** |
| Taylorville | IGCC | CCS | cancelled | 2 | 3.5 | **75%** |
| FutureGen 1.0 | IGCC | CCS | cancelled | 0.95 | 1.8 | **89%** |
| Edwardsport | IGCC | No CCS | constructed | 2 | 3.5 | **75%** |
| Boundary Dam (overall costs) | PC (rebuilt) | CCS | active | 1.24 | 1.355 | **9%** |
| Boundary Dam (CCS costs) | PC (rebuilt) | CCS | active | 0.89 | 1 | **12%** |
| W.A. Parish | Existing PC | CCS | active | 0.338 | 0.775 | **129%** |
| Mountaineer (Validation-scale CCS) | Existing PC | CCS | completed | --- | 0.1 | **---** |
| Mountaineer (Commercial-scale CCS) | Existing PC | CCS | cancelled | 0.668 | 1 | **50%** |
| Mountaineer (Commercial-scale CCS) With Estimated UIC cost risk | Existing PC | CCS | cancelled | 0.668 | 1.3 | **95%** |
| Trailblazer | PC | CCS | cancelled | 2.5 | 3.5 | **40%** |
| John W. Turk | USC PC | No CCS | constructed | 1.3 | 1.8 | **38%** |

Concerns that EPA's cost evaluation relies only on the two NETL reports become even more pronounced when considering the large difference of the estimated costs projected by EPA in the proposed rule and the actual costs that active CCS projects are incurring. The table below summarizes this comparison.

| | Unit Type | GHG Control | $/kw (net) |
|---|---|---|---|
| Hydrogen Energy California[192] | IGCC | CCS | $16,000 |
| Texas Clean Energy Project[193] | IGCC | CCS | $15,510 |
| Kemper[194] | IGCC | CCS | $9,450 |
| FutureGen 1.0[195] | IGCC | CCS | $6,545 |
| Taylorville[196] | IGCC | CCS | $5,814 |
| Trailblazer[197] | IGCC | CCS | $4,167 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | IGCC | CCS | $4,451 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | IGCC | CCS | $3,802 |
| | | | |
| FutureGen 2.0[200] | PC/Retrofit | CCS | $17,879 |
| Boundary Dam (retrofit and CCS)[201] | PC/Retrofit | CCS | $12,318 |
| Boundary Dam (CCS only)[201] | PC | CCS | $9,091 |
| W.A. Parish[202] | PC | CCS | $3,100 |
| Mountaineer (validation scale) | PC | CCS | $5,000 |
| Mountaineer (commercial scale) | PC | CCS | $4,255 |
| Mountaineer (commercial scale + UIC) | PC | CCS | $5,532 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | PC-supercritical | CCS | $4,070 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | PC-supercritical | CCS | $3,972 |

[192] https://sequestration.mit.edu/tools/projects/DOE%20projects/CCPI%20projects/HECA-Tech-Update-2011.pdf
[193] https://sequestration.mit.edu/tools/projects/tcep.html
[194] www.reuters.com/article/2014/04/29/utilities-southern-kemper-idUSL2N0NL2K220140429
[195] www.powermag.com/cover-story-futuregen-zero-emission-power-plant-of-the-future/?pagenum=2
[196] http://sequestration.mit.edu/tools/projects/taylorville.html
[197] http://sequestration.mit.edu/tools/projects/tenaska.html
[198] "*Cost & Performance Baseline for Fossil Energy Plants*" Rev 2a. (Sept 2013). NETL p. 5
[199] "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*" Rev 1. (Sept 2013) NETL. pp. 16-17.
[200] http://energy.gov/sites/prod/files/2013/04/f0/EIS-0460-DEIS-Summary-2013.pdf
[201] https://sequestration.mit.edu/tools/projects/boundary_dam.html
[202] www.netl.doe.gov/publications/others/nepa/deis_sept/EIS-0473D_Summary.pdf

| | Unit Type | GHG Control | $/kw (net) |
|---|---|---|---|
| Edwardsport[203] | IGCC | none | $5,538 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | IGCC | No CCS | $3,097 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | IGCC | No CCS | $2,790 |
| | | | |
| Turk | PC-USC | none | $2,885 |
| NETL: "*Cost & Performance Baseline for Fossil Energy Plants*"[198] | PC-supercritical | No CCS | $2,296 |
| NETL: "*Cost & Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*"[199] | PC-supercritical | No CCS | $2,296 |

Strong conclusions can be drawn from the cost estimates above regarding the state and cost of CCS development for coal-based generating units, including the following:

- All of the projects are utilizing FOAK technologies
- All of the projects are very expensive. The active projects that remain are financially supported with significant government resources
- All of the projects have experienced significant cost escalations (up to 129% increase)
- The cost estimates between projects varies significantly
- The magnitude of costs, large degree of variation between project estimates, and significant cost escalations are <u>all</u> indicative of the application of FOAK technologies.

These conclusions represent a significant, if not prohibitive, barrier to the development of future CCS projects. These types of financial challenges for developing CCS technologies for coal-based generating projects have been widely recognized. For example:

- On February 11, 2014, Deputy Assistant Secretary of Energy Dr. Julio Friedmann testified that first generation carbon capture technology on coal-based generating plants will increase the cost of electricity by 70 to 80%.[204]
- In 2013, the Global CCS Institute estimated first-of-a-kind CCS would increase the cost of electricity by 61 to 76% for post-combustion processes and 37% for IGCC units.[205]
- 2010 DOE/NETL CCS Roadmap estimated CCS will add 80% to the cost of a new pulverized coal plant and 35% to the cost of a new IGCC plant.[206]

[203] www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/presentations/EdwardsportIGCC-041609.pdf
[204] Friedmann, J. Oral Testimony before U.S. House of Representatives Committee on Energy and Commerce. (Feb. 11, 2014)
[205] "The Global Status of CCS: 2013". (Oct. 2013). Global CCS Institute. p 172.
[206] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec. 2010). p. 10

The following contrasts the types of CCS-related cost escalations that EPA relies upon in their analysis of the BSER:

**EPA Cost Analysis of CCS Technologies**[207]

| Unit | Configuration | LCOE ($/MWh) | CCS Related Cost Increase | EPA Conclusion |
|---|---|---|---|---|
| SCPC | No CCS | 92 | --- | --- |
| SCPC | Partial CCS, No EOR | 110 | 20% | Justifies partial capture as the BSER |
| SCPC | Full, 90% CCS | 147 | 60% | Too expensive. Full capture eliminated as BSER |
| IGCC | No CCS | 97 | --- | --- |
| IGCC | Partial CCS, No EOR | 109 | 12% | Justifies partial capture as the BSER |
| IGCC | Full, 90% CCS | 136 | 40% | Too expensive. Full capture eliminated as BSER |

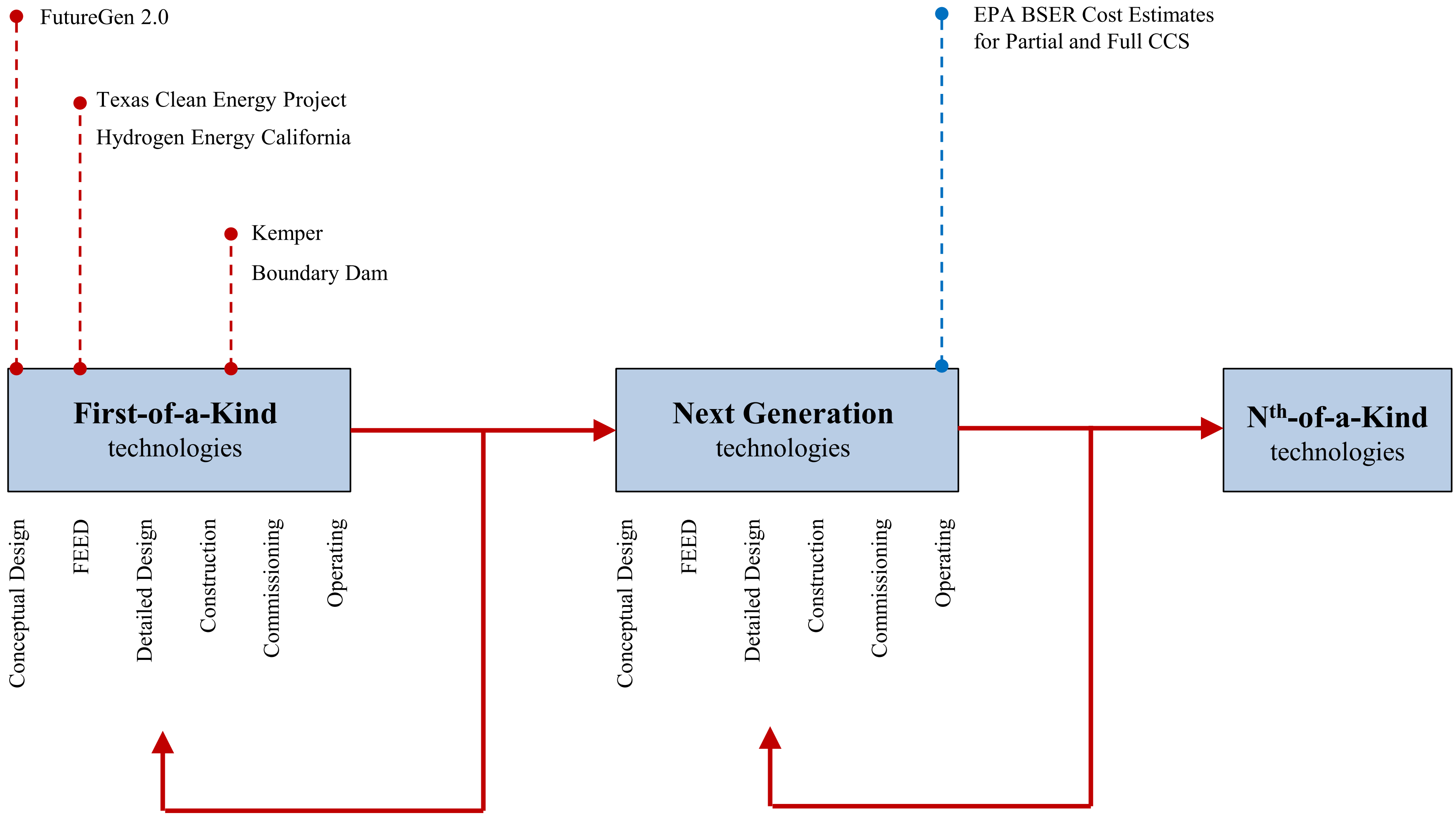
When compared to cost of actual projects and the assessments from organizations that are much more directly involved CCS development, EPA's cost assessment misses the mark by a very wide margin both in terms of the magnitude of costs involved and their conclusions on the current state of CCS development. For example, EPA's range of a 12 to 60% cost increase for CCS is far below the estimates of DOE and others that approach 80% or more

The figure on the following page contrasts the state of development represented by active CCS related projects and by EPA's BSER cost evaluation. The figure indicates that EPA's cost estimates are very ambitious and not representative of the actual state of CCS development. As (and if) these active CCS projects are constructed and operated, the lessons learned will lead to future designs that may themselves be characterized as FOAK technologies as well, or to future designs of next generation, optimized technologies that represent progress towards the development of technically feasible processes than can potentially be adequately demonstrated.

In conclusion, the flawed cost estimates that EPA relies upon are not reliable for assessing the current or future cost of CCS projects, and are insufficient to evaluate the current status of CCS development. EPA eliminated full capture CCS as the BSER on the sole basis that it would be too expensive (40 to 60% cost increase).[208] If the 40-60% increase was sufficient to eliminate full capture, then the 80+% increase experienced by active projects and estimated by DOE and others is **more than sufficient** to also eliminate partial capture as the BSER.

[207] 79 Fed. Reg. 1476 (January 8, 2014)
[208] 79 Fed. Reg. 1477. (January 8, 2014).

**Development Status of CCS Technologies**



### G. EPA's evaluation of emission reductions fails to demonstrate that CCS is the BSER

The proposed rule cites Section 111(a)(1), along with Court determinations to note that "in considering the various factors and determining the 'best system,' the EPA must be mindful of the purposes of section 111, and the Court has identified those purposes as...reducing emissions as much as practicable."[209] EPA's consideration of emission reductions is flawed because the agency relies on ambiguous criteria to determine "as much as possible," fails to fully consider the magnitude of emission reductions that may be achieved from highly efficient processes alone, and utilizes loose, qualitative statements on CCS related emission reductions. EPA's determination that partial-CCS is the BSER from an emissions reductions perspective is based only on its qualitative assessment that CCS provides "significant" and "meaningful" reductions.[210] EPA provides no information on the baseline used to assess emission reductions and provides no information on the types of criteria considered in determining "significant" and "meaningful." Despite the "significant" and "meaningful" emission reductions that EPA expects will result, the agency notes that they "do not anticipate any notable $CO_2$ emission reductions associated with the rulemaking."[211]

### H. EPA fails to demonstrate that technology advancement will result from selecting CCS as the BSER

As part of the BSER analysis, EPA considered whether their determination would "promote the development and implementation of technology."[212] EPA concluded that establishing partial CCS as the BSER would "promote implementation and further development of CCS technologies"[213] and would "encourage continued research and development efforts."[214]

EPA is incorrect. AEP has provided comments on the magnitude of development challenges and the significant time and resources required to overcome these barriers. The technical, financial, and regulatory challenges to building new coal-based generation are daunting. Adding the challenges associated with integrating CCS, along with the uncertainty of whether compliance with the GHG NSPS is even achievable, creates an investment risk that no

[209] 79 Fed. Reg. 1463 (January 8, 2014)
[210] 79 Fed. Reg. For example 1436 related to use of the terms "meaningful" and "significant"
[211] 79 Fed. Reg. 1496. (January 8, 2014)
[212] 79 Fed. Reg. 1462. (January 8, 2014).
[213] 79 Fed. Reg. 1436. (January 8, 2014).
[214] 79 Fed. Reg. 1480. (January 8, 2014).

developer would accept. In effect, the proposed rule would prohibit the development of new coal generation, and in turn would negatively impact, if not halt entirely, any advancement in development of CCS technologies.

## IX. Other Considerations Demonstrate that Partial Capture CCS is not the BSER

### A. AEP's CCS Program demonstrates that CCS is not the BSER

From 2009 to 2011, AEP operated the first integrated CCS project in the world on a coal-based generation plant. AEP submitted extensive comments to EPA in 2012 that described the Mountaineer Plant CCS project, discussed lessons learned, and summarized key challenges for CCS to become a technically feasible and commercially viable technology. AEP's comments attempted to alleviate misconceptions by EPA in the 2012 proposed rule by placing into proper context the scope and outcome of its CCS program. Unfortunately, EPA ignored or gave negligible attention to those comments. The current proposed rule continues to misrepresent the scope, results, and lessons learned from the Mountaineer Plant CCS project. The following is another attempt to place the project into proper context in the hope that the comments will be fully considered as part of a fair, objective evaluation of CCS in the final rule.

AEP has been a strong advocate for the development and advancement of CCS technologies, and believes that technological solutions are critical to reducing emissions from and improving the performance and reliability of electric generation processes. Nonetheless, as an outcome of our first-hand experience and as reinforced by other public and private efforts, AEP is convinced that CCS is many years from being proved to be a technically feasible, adequately demonstrated, and commercially viable solution for reducing $CO_2$ emissions.

A number of qualifications must be made in order to properly understand what was and was not accomplished by AEP at the Mountaineer Plant. First, EPA claims that "[p]*rojects such as AEP Mountaineer have successfully demonstrated the performance of partial capture CCS on a significant portion of their exhaust stream*."[215] EPA's claim is misleading and inaccurate. AEP <u>did not</u> construct or operate a "partial capture CCS on a significant portion" of the Mountaineer Plant flue gas. AEP did successfully deploy a $CO_2$ capture system on a <u>validation-scale</u> slip-stream process (20 MW equivalent, or 1.5% of the Mountaineer Plant's 1,300 MW capacity). The success of that project was in proving that the technology was compatible with

[215] 79 Fed Reg. 1436 (January 8, 2014).

power plant conditions and that the technology could successfully capture $CO_2$ at a coal-fired power plant. The project *did not prove* that commercial-scale CCS is technically feasible or that it could be adequately demonstrated. AEP did consider a commercial-scale project, but after performing a front-end engineering and design ("FEED") study and being unable to obtain necessary cost-recovery approval from regulators, decided to cancel the project.[216] It should be clearly understood that the validation project *did not* constitute a commercial demonstration and that the technology *has not* been proven to be technically feasible or adequately demonstrated at a commercial-scale.

AEP partnered with Alstom to validate the chilled ammonia process for capturing $CO_2$ from the Mountaineer Plant. The validation-scale system was operated from September 1, 2009 through May 31, 2011. Over that period, the project captured more than 50,000 metric tons of $CO_2$. The system was built as a validation platform, with flexibilities for systematic process adjustments, which enabled operators to optimize and control all process streams and energy inputs to thoroughly evaluate the technology. Once completed, the AEP/Alstom team developed a comprehensive understanding of the chilled ammonia process and specifics about the operation of each system within the process. This background, including a detailed understanding of key process parameters, such as energy penalty, reagent loss, and $CO_2$ capture rate, facilitated moving forward with the FEED study for a commercial-scale project.

While the capture process was shown to be technically feasible under coal-fired power plant conditions, many important aspects of the technology must be demonstrated at full-scale (a minimum of approximately 250-MWe, or more than 12 times the size of the validation system at Mountaineer) before a process supplier or power plant owner could realistically consider deploying the technology commercially. For example, many post-combustion $CO_2$ capture technologies would use enormous quantities of steam in the process. If the steam is taken from the existing power plant boiler/steam-turbine system, then that represents a significant power generation heat cycle change, which requires a steam path redesign and modification of the generating unit. Once completed, the modifications intrinsically tie together the generating unit with the $CO_2$ capture system. Such a combination of systems has never been demonstrated and must be rigorously tested and optimized before the technology can be deemed reliable, proven,

[216] The Final Technical Report for the commercial scale CCS project can be found at www.netl.doe.gov/technologies/coalpower/cctc/ccpi/bibliography/demonstration/ccpi_aep/MTCCS%20II%20Final%20Technical%20Report%20Rev1.pdf.

or commercially viable. In addition, the equipment to capture $CO_2$ is large and an entire system capable of treating the effluent of a power plant requires extensive tracts of land. In the AEP/Alstom study of a commercial scale installation, the system was designed to capture 265 MWe worth of flue gas (approximately 1/5 of the plant output), yet it occupied a footprint nearly the same size as the original power plant, or about 11 acres. Size alone would preclude use of the technology at many existing power plants and must be carefully considered in the design of any new power plant.

AEP also partnered with Battelle to study and validate sequestration of $CO_2$ into deep saline reservoirs near the Mountaineer Plant. Approximately 37,000 metric tons of the captured $CO_2$ was compressed and injected into two saline reservoirs located roughly 8,000 feet beneath the plant site. Besides two injection wells, one into each of the reservoirs, AEP deployed three deep monitoring wells at various distances from the injection point. Many experimental and novel monitoring technologies were also tested at the site. The difficult nature of the geology in the area proved some of these technologies to be inappropriate for the application. Again, while the project was successful in injecting and confining the $CO_2$ sent to the wellheads, the scale was far from being representative of what would be required for full-scale deployment. Furthermore, great uncertainty remains surrounding the liability for and future ownership of injected $CO_2$, which could dissuade any future developer. The experience of the AEP CCS program also identified a number of practical considerations that are significant barriers to any CCS project. These aspects are discussed in greater detail in Section C below

Of note, any commercial-scale CCS project is going to be very expensive. The commercial-scale CCS project that was considered for the Mountaineer Plant would have captured $CO_2$ from 20% of the flue gas. The conceptual project cost of $668 million escalated to approximately $1 billion after the FEED study was completed. These costs were expected to continue to escalate throughout the detailed engineering, construction, and commissioning phases of the projects. One cost that was not fully included in the $1 billion estimate relates to uncertainties on the cost to comply with requirements of the underground injection control (UIC) permit. Although the project was cancelled prior to even filing an application for a UIC permit, it was estimated based on the requirements in the Class VI UIC Guidelines that the project could have been required to install an additional 75 intermediate and deep monitoring wells alone at an estimated cost of nearly $300 million – a 30% increase in the estimated $1 billion CCS project – which again represents only 20% of the plant output!

A review and discussion of the lessons learned from the Mountaineer CCS Program were documented in a number of reports submitted to the Global CCS Institute ("GCCSI"). EPA is strongly encouraged to review and apply the information from these reports in the BSER evaluation for the final rule. All of these reports are readily accessible through the GCCSI website,[217] including the following:

- CCS Lessons Learned Report: AEP Mountaineer CCS II Project Phase 1[218]
- AEP Mountaineer II Project – Front End Engineering and Design (FEED) Report[219]
- AEP Mountaineer CCS Business Case Report[220]

EPA is also encouraged to review the draft Environmental Impact Statement for the Mountaineer commercial-scale demonstration project to gain greater perspective on the scope and magnitude of issues that any CCS project must address. It is especially revealing that these significant challenges are only for a 20% capture project. A requirement to capture 40%, 60% or more would create a level of barriers that would be too prohibitive for most, if not all, project developers to overcome. The draft EIS can be found on the DOE website.[221]

In conclusion, it is more accurate to state that the AEP Mountaineer project proved that the technology shows promise for future plant applications. However, technically feasible and adequately demonstrated CCS is still many years from being proven at a commercial scale, still requires development of an appropriate regulatory or legal framework, and, as a result, cannot yet be deemed as commercially viable technology.

### B. Numerous Public and Private Efforts demonstrate that CCS is not the BSER

Numerous assessments by public and private organizations recognize that CCS has not been proven to be technically feasible or adequately demonstrated for coal-based generation and that significant development barriers remain. For example, a November 17, 2011 Reuters article noted that "[then EPA Administrator Lisa] Jackson, whose agency looked at CCS as it developed

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[217] www.globalccsinstitute.com/search/apachesolr_search/AEP

[218] A copy is attached in Appendix C. (www.globalccsinstitute.com/publications/ccs-lessons-learned-report-american-electric-power-mountaineer-ccs-ii-project-phase-1)

[219] www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report

[220] www.globalccsinstitute.com/publications/aep-mountaineer-ccs-business-case-report

[221] http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0445-DEIS-01-2011.pdf

the rules, said the technology has long way to go. 'It can be years, maybe a decade or more, until we have the technology available at a commercial scale,' she said."[222]

These assessments consistently conclude that the current scope and progress of CCS development programs are insufficient to drive the near-term completion of commercial-scale CCS projects whose operating experience is needed to adequately demonstrate the technology. In fact, most of the studies indicate that technically feasible and adequately demonstrated CCS technologies are *at least* a decade or more away, *even if* much more ambitious RD&D programs were implemented. EPA ignores these studies and assessments in the proposed rule, although it is noteworthy to reiterate that these are the type of "major assessments" that EPA has described as being of significant value for evaluating complex issues and for informing the Administrator's "best judgment."[223] Appendix B summarizes a portion of these studies and major assessments to highlight the actual state of CCS development, to identify the magnitude of development that remains for the technology to be adequately demonstrated, and to further indicate that CCS is not the BSER for coal-based generating units.

### C. Practical development considerations demonstrate that CCS is not the BSER

The prior comments were provided to critically evaluate specific aspects of the EPA BSER analysis. Apart from those comments and outside the complex dialogue on issues such as the interpretation and application of NSPS regulatory requirements, a host of practical considerations to CCS development exist that represent significant challenges to any CCS project. In many cases, these practical considerations are more of a barrier to the adequate demonstration and commercialization of CCS.

1. <u>CCS is not just another control technology</u>

The scope and complexity of development issues for CCS are dramatically different than for other emission controls, such as flue gas desulfurization ("FGD") or selective catalytic reduction ("SCR") technologies. Shoehorning the development of CCS into the "typical" development curves of FGD or SCR technologies is an imperfect comparison that produces a false perception of the steps and timeline for CCS development and in no way establishes the standard for or offers guarantees on the success of CCS development.

[222] www.reuters.com/article/2011/11/17/usa-epa-carbon-idUSN1E7AG0WU20111117
[223] See Section VIII.A for AEP comments related to the use of "major assessments."

The CCS development challenges at coal-based power plants are unique from other technologies and are not one-size-fits-all for all potential projects. This is attributed to a greater complexity of process integration issues, the magnitude of operational considerations, and the significant increases to cost of electricity production. CCS also presents unique issues regarding the enormous amounts of $CO_2$ byproduct that must be handled, transported, and stored in geologic formations. For example, coal-combustion ash and FGD-related by-products are solid materials that can be handled and stored in a landfill, while $CO_2$ is generally captured and compressed to a supercritical liquid, which must be stored in deep geologic formations, and will be subject to a more extensive, diverse, and in many cases undeveloped set of regulatory and legal requirements. EPA has acknowledged in their guidance document for PSD permitting for GHG's that the scope of design, construction, and operation considerations are much different and unique for CCS compared to other emission control systems by noting:

> "*EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage.*"[224]

2. The cost of commercial-scale CCS remains a significant unknown

Regardless of whether the current state of CCS development is characterized as first-of-a-kind, $n^{th}$-of-a-kind, or something in between, the cost of the technology is very expensive, which has restricted and, in many cases, prohibited, development. Each example of a potential commercial-scale CCS on a coal-based generating unit has experienced a significant escalation in costs. The wide disparity in the cost estimates of current efforts is indicative that CCS is not a one-size-fits-all technology, that project-specific cost drivers are significant, that reliable estimates of CCS costs are evolving, and that future CCS cost are highly speculative.

3. The energy required to power CCS systems is large and represents a significant development challenge

The energy demand and parasitic load to power CCS systems is significant. As noted by the Department of Energy:

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[224] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." (Mar. 2011). p. 36. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

"*The combined effect of steam and auxiliary power required to operate the $CO_2$ capture and compression systems is that the net power output of the unit would decrease by approximately 30 percent*"[225]

The significant energy requirements for CCS systems have been widely recognized and reported by others as well, including in a report by The U.S. Government Accounting Office:

"*Current CCS technologies require significant energy to operate... Parasitic loads...for current CCS technologies are estimated to be between about 21% and 32% of the plant output for post-combustion* [capture systems]"[226]

For context, assume that a CCS system installed on 600 MW coal-based power plant would require 30% of the load to operate, or approximately 180 MW. The electricity required to capture $CO_2$ from this 600 MW unit is equivalent to the annual electricity consumed by nearly 125,000 households.[227] If the purpose of the power plant in the example is to meet a customer demand of up to 600 MW, then the plant would have to be oversized to accommodate the large CCS-related auxiliary load or a separate generation source would be required.

Increasing the size of the unit would result in greater coal consumption, greater water usage, and greater emissions, byproducts, and water discharges to power the CCS system. The NRG Parrish CCS project is using an approach whereby a separate 80 MW natural-gas fired combustion turbine unit has been constructed for the purpose of powering the carbon capture system.[228] In other words, a separate, uncontrolled $CO_2$ emission source is being constructed to power equipment that will capture $CO_2$ emissions from another combustion source that will then be used for producing oil that will eventually be combusted and result in more, uncontrolled $CO_2$ emissions.

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[225] DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap. (Dec 2010). p.26

[226] "Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions." U.S. GAO. (Jun 2010).

[227] Assumes 85% capacity factor of plant and average residential demand of 10,873 kw/yr (per EIA www.eia.gov/tools/faqs/faq.cfm?id=97&t=3);

[228] 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project.

Based on the estimates calculated below, this type of configuration would actually result in more $CO_2$ to the atmosphere than if the unit was left uncontrolled!

| | |
|---|---|
| New $CO_2$ Emission from Operation of $CO_2$ Capture & Recycle Facility (new combustion turbine) | = +710,000 tonnes/yr[229] |
| $CO_2$ Captured from Coal Unit | = -1,500,000 tonnes/yr[230] |
| Estimate Barrels of Oil from Injected $CO_2$ | = 3,750,000 barrels/yr[231] |
| Estimated $CO_2$ from Combustion of Recovered Oil | = +1,612,500 tonnes/yr[232] |
| **Net $CO_2$ Emissions from Project = +710,000 – 1,600,000 + 1,612,500** | **= +722,500 tonnes/yr** |

It is clear from an objective accounting of $CO_2$ emissions in this example that CCS provides few, if any, meaningful emission reductions. It is also clear that significant development is needed to reduce the energy demand of $CO_2$ capture systems before CCS can be legitimately considered as technically feasible or adequately demonstrated.

4. Integration of CCS and coal-based generation technologies introduces unique development challenges

The integration of CCS systems to coal-based generation technologies introduces a number of unique development challenges that include:

- Integration of Operating Philosophies: The use of CCS represents the integration of two different operating philosophies: power plant vs. chemical plant. Power plant systems are designed to accommodate dynamic operating scenarios where processes routinely cycle in different modes depending on variables such as changes in electricity demand or fuel characteristics. Chemical plants, which closely resemble $CO_2$ capture processes, are typically designed for steady-state operations with process inputs that have fixed quantities and rigid purity specifications. Integrating these philosophies at a commercial-scale presents significant engineering and design challenges whose solutions have yet to be adequately demonstrated as technically feasible or cost effective.

229 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project. (p 30905)
230 Id
231 Based on EOR rate of 1 barrel per 0.40 $CO_2$ tonnes injected. "Enhanced Oil Recover & CCS." Carter, L. US Carbon Sequestration Council. (Jan 14, 2011)
232 Based on $CO_2$ emission factor of 0.43 tonnes $CO_2$/barrel of oil combusted. www.epa.gov/cleanenergy/energy-resources/refs.html (accessed Feb 21, 2014)

- Capture System Design Specifications: Certain capture systems have stringent process chemistry requirements that demand pristine flue gas conditions that in some cases are well beyond the capability of state-of-the-art flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems. For such systems, additional flue gas polishing systems would be required to accommodate the capture process.

- Capture System Power and Steam Requirements: Energy consumption requirements by the capture system represent the most daunting barrier to economical CCS deployment. Current estimates are that operation of the CCS system would demand 30% of the net output from the generating unit.[233] Some capture systems are also designed to consume large amounts of steam, which also impact overall unit performance and efficiency. The large energy and steam requirements for certain systems to operate capture systems introduces unprecedented engineering and operating challenges to integrate these systems into power plant designs and process flow schemes.

- Footprint of Capture System: The size of the capture systems is a concern as current design configurations would more than double the footprint of a typical power plant, which introduces substantial implications with respect to land availability, constructability, and project costs. For example, the capture system for the AEP commercial-scale Mountaineer Plant CCS project would have encompassed over 13 acres, which is over double the size of the generating unit itself. Notably, the footprint for the Mountaineer Plant capture system was for a system designed to capture only 20% of output from the unit! While some economies of scale would be expected through process and design optimization, the capture system footprint will remain very large. The large footprint is also another example of the magnitude and complexity of equipment and systems within the capture process, which introduces significant performance and reliability challenges. In other words, more equipment and area introduces greater operational risks. The figure below illustrates the scale of

[233] DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap. (Dec 2010). p.26

the capture system that was being planned for the 20% $CO_2$ capture system at the Mountaineer Plant.

Mountaineer 1300 MW Power Block

SOx / NOx / PM Controls

20% CCS System

- Unit Availability Risks from Geologic Storage and EOR Processes: Operation and performance risks specific to the geologic storage or EOR systems introduces integration concerns as these risks can impact the performance or constrain the operation of the capture system and power plant. For example, a CCS project aligned with an EOR system would be constrained by the assurance that the demand for $CO_2$ from the EOR operator always meets or exceeds the $CO_2$ produced by the power plant. When, not if, but when the demand for $CO_2$ from the EOR operator is insufficient, then the power plant would be forced vent captured $CO_2$ to the atmosphere, curtail operations or shutdown. Power plants are developed, and in many states are regulated, on the basis of being able to reliably meet a specified demand for electricity – an essential public need. Subjecting the availability of power generation to the availability to EOR operations fails to ensure that the obligation to provide reliable power can be met. Likewise, similar constraints are reasonably to be expected to occur with geologic storage systems where a host of known and unknown variables could constrain the availability and performance of injection wells. AEP experienced these types of constraints during the operation of the validation-scale CCS project. The scope of these risks coupled with a number of legal and regulatory uncertainties associated with long-term geologic storage is another indication that CCS has not been adequately demonstrated to be technically feasible or commercially viable.

5. Undeveloped regulatory and legal considerations may alone prohibit the development and adequate demonstration of CCS projects

A broad scope of legal and regulatory uncertainties exist that apply to each aspect of the CCS process (capture, transport, and storage), which must be addressed before any CCS project can be developed. A discussion of these issues follows to provide context on the breadth of issues that remain to be resolved and to demonstrate the significant challenge that these issues pose to CCS development. Unknowns exist regarding how these issues will be addressed within state boundaries, and also with respect to interstate considerations. A recent study by the West Virginia Chamber of Commerce surveyed all 50 states to assess the readiness of their state regulations and policies to accommodate CCS projects. Most states are not well prepared and are not proactively preparing programs to regulate CCS projects, as summarized below:[234]

| | Obtained UIC Class VI Permitting Primacy | Identified Property Rights to be Secured | Streamlined procedures for the taking, unitization or use of property rights | Addressed Long-term Care Provisions | Streamlined procedures for the siting or construction of CO2 pipelines |
|---|---|---|---|---|---|
| States that responded yes | 0 states (0%) | 14 states (28%) | 8 states (16%) | 12 states (24%) | 11 states (22%) |

The development challenges related to legal and regulatory issues have been recognized in many assessments, including the following:

[234] "A State-by-State Survey of Existing Statutes and Rules Related to the Transportation and Geologic Storage of Carbon Dioxide" (March 20, 2014). West Virginia Chamber of Commerce. EPA Docket ID: EPA-HQ-OAR-2013-0495-4733

- The Interagency Task Force on CCS, which concluded that "for widespread cost-effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship" and that "regulatory uncertainty has been widely identified as a barrier to CCS deployment."[235]

- The Secretary of Energy's National Coal Council, which determined that "[t]he management of long-term liability risks is [a] critical consideration for CCS projects...[U]ncertainty regarding long-term liability options remains a challenge."[236]

- A 2011 study from the Harvard Kennedy School's Energy Technology Innovation Policy Research Group, which found that for the commercial-scale CCS demonstration projects in Phase III of the DOE's Regional Carbon Sequestration Partnerships Program, "[l]iability for sequestration of $CO_2$ and lack of coordination among regulatory authorities" would pose "significant barriers."[237]

- A 2014 report by the Congressional Research Services noted that: "Development Phase projects will provide a better understanding of regulatory, liability, and ownership issues associated with commercial scale CCS. These nontechnical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting $CO_2$ safely and in perpetuity are resolved."[238]

*a. <u>EPA has ignored property rights issues that are barriers to the adequate demonstration and development of CCS</u>*

In addition to the significant technical and financial challenges related to geologic sequestration, equally significant legal and regulatory challenges exist in regards to the ownership, access, and use of the geologic area (e.g. pore space) for the storage of $CO_2$. Key questions related to property rights, many of which remaining to be resolved, include:

- Who holds ownership rights to pore space? Surface-owner, mineral rights-owner, state or Federal government, other;
- Does surface or mineral-rights ownership mean owners have a protectable interest?[239]
- To the extent that protectable interests exist, are those interests limited to within a specific depth below the surface of the earth?[240]

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[235] Report of the Interagency Task Force on Carbon Capture and Storage, pp. 10-14 (Aug 2010).
[236] Expediting CCS Development: Challenges and Opportunities, p. 83 (Mar 2011).
[237] Craig A. Hart, Putting It All Together: The Real World of Fully Integrated CCS Projects, Discussion Paper 2011-06, Belfer Center for Science and International Affairs (Jun 2011) available at http://belfercenter.ksg.harvard.edu/files/Hart%20Putting%20It%20All%20Together%20DP%20 ETIP%202011%20web.pdf).
[238] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service. p. 23
[239] "A State-by-State Survey of Existing Statutes and Rules Related to the Transportation and Geologic Storage of Carbon Dioxide" (Mar 20, 2014). West Virginia Chamber of Commerce. p. 10. EPA Docket ID: EPA-HQ-OAR-2013-0495-4733

- Does the use of pore space necessitate the need acquire access or pore space rights?
- How are pore space rights acquired?
- How do existing programs for eminent domain, unitization, public use, or voluntary acquisition translate to pore space acquisition?[241]
- How does existing eminent domain authority apply to $CO_2$ pipeline development?
- What is the relationship between the use of pore space for $CO_2$ sequestration and liabilities related to the ownership and use of surface or mineral rights?
- Who has regulatory jurisdiction over issues related to property rights? State utility commissions, state environmental protection agencies, state natural resource departments, etc.

A number of options have been identified for resolving these issues. Addressing each will require time and resources, but most importantly will require a desire by individual states to proactively resolve these issues and to become prepared to efficiently and effectively regulate future CCS projects. Without these steps, such regulatory and legal issues will remain significant barriers to CCS development.

*b.* *<u>EPA has ignored long-term stewardship and liability issues, which are barriers to the adequate demonstration and development of CCS</u>*

Considerations related to the long-term care of $CO_2$ that has been geologically sequestered focus on two key issues: stewardship and liability. Stewardship involves the monitoring and assessment of the geologic storage area, while liability relates to responsibility after closure of the injection process. Although the EPA Class VI injection well regulations establish monitoring and post-injection site care requirements for a specified period (50 years post-injection), a number of uncertainties during and beyond that period remain that must be addressed, including:

- Post-closure requirements for transfer of liability? The federal government and many states have yet to provide a mechanism for the transfer of liability.[242]
- Financial responsibility requirements to assure the availability of funds for the life of the project (including post-injection site care and emergency response)? EPA Class VI rules include some requirements, but how far do these extend into the future?
- Post-closure monitoring requirements? EPA Class VI rules have some requirements, but how far do these extend into the future?

[240] Id. p. 11.
[241] Id. pp. 18-19.
[242] Id. pp. 32-33.

c. *The EPA Class VI UIC permitting process and requirements introduce uncertainties that are a barrier to the adequate demonstration and development of CCS*

The permitting program for the EPA Class VI underground injection control (UIC) program is in its infancy. A handful of states are pursuing primacy over the permitting process, but none have obtained it. Currently, EPA has primacy over the permitting process in all states.[243] To date, EPA has not issued a single final Class VI permit.[244] The application process is extensive and requires information to be provided that will be very time-consuming and expensive to obtain – if indeed it is even obtainable given the size of the area that must be considered to accommodate the volume of $CO_2$ storage associated with a coal-based generation unit. For example, the Class VI permit must include information such as:

> "*A map of the injection well...and the applicable area of review. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads*."[245]

As the area of review is likely to be many tens of square miles in size for a commercial-scale project, the research and preparation of such information alone will be tedious and time consuming process that will result in a voluminous submittal the regulatory agency for review. It is to be determined whether the application process itself represents a critical barrier in the development of CCS. Another unknown that remains is how the extensive information provided in the application will translate into the actual permit requirements and whether such requirements would be so onerous to comply with that they could effectively prohibit a CCS project from occurring. For example, based on information in EPA's final Class VI UIC rule regarding the number of monitoring wells that may be necessary,[246] the commercial-scale CCS Mountaineer project could potentially have been required to install an additional 75 monitoring wells at an estimated cost of nearly $300 million, which represents a 30% increase in the estimated $1 billion CCS project cost – again this is for the geologic storage of only 20% of the

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[243] Id. pp. 6-10.
[244] "U.S. EPA Seeks Public Comment on Proposed Sequestration Permits in Central Illinois." (Mar 31, 2014). EPA Press Release.
[245] 75 Fed. Reg. 77292. (Dec. 10, 2010).
[246] 75 Fed. Reg. 77279-77280. (Dec. 10, 2010).

plant output! These types of unknowns represent significant challenges to the adequate demonstration and development of CCS.

In addition to the time required to prepare the Class VI UIC permit application, the time required for the regulatory agency to process the application and issue a final permit represents a significant development hurdle as well. Archer Daniels Midland filed the very first Class VI UIC permit applications to U.S. EPA, one in July 2011 and one in December 2011. Nearly three years later, both applications remain under technical review by U.S. EPA. Remaining steps for processing these applications include the issuance of a draft permit, public commenting period, further technical review and issuance of a final permit.[247] These steps could easily increase the permitting by years. Any potential project cannot move forward with detailed engineering and design, or construction without the necessary regulatory approvals (e.g. UIC permit) in place and without the certainty that related regulatory requirements will be obtainable, cost-effectively, and achievable throughout the operation of the facility. For example, a permitting process that requires five years or more to obtain a final permit is likely to be prohibitive to any future project that must rely on CCS technology.

Finally, the Class VI UIC regulation should not be misconstrued as having addressed all barriers to the geologic sequestration of $CO_2$. As noted in a 2014 report by the Congressional Research Service:

> "*The development of the regulation for Class VI wells highlighted that EPA's authority under the SDWA is limited to protecting underground sources of drinking water but does not address other major issues. Some of these include the long-term liability for injected $CO_2$, regulation of potential emissions to the atmosphere, legal issues if the $CO_2$ plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected $CO_2$ plume, and ownership of the subsurface reservoirs (also referred to as pore space).*"[248]

*d.* *<u>EPA ignores interstate and comingling issues that are barriers to the adequate demonstration and development of CCS</u>*

While the aforementioned questions show how far individual state requirements must mature to be able to accommodate CCS within state boundaries, another layer of complexity occurs when these questions are considered in context with interstate boundaries or with the comingling of geologically stored $CO_2$ from multiple sources. The relationship between

[247] www.epa.gov/region5/water/uic/adm/index.htm (Accessed March 3, 2014)

[248] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" (Feb 10, 2014). Folger, P. Congressional Research Service. p. 23

individual state regulations on property rights, long-term stewardship and liability, and permitting has, in most cases not yet been determined for individual injection wells. Likewise, these issues need to be resolved to address the intrastate or interstate geologic storage of $CO_2$ from one source that over time combines with the $CO_2$ stored by another source.

*e.* *<u>Uncertainties regarding the applicability of RCRA regulations remain a barrier to CCS development</u>*

EPA has conditionally excluded $CO_2$ streams captured from power plants and industrial systems as a hazardous waste under the RCRA program if they are injected under a UIC Class VI permit. However, uncertainties remain regarding the extent of that exemption, which could actually discourage the use of anthropogenic $CO_2$ for EOR operations. Although EPA notes in the final rule revising the RCRA requirement that the injection of $CO_2$ for EOR or other commercial purposes "would not generally be a waste management activity," questions remain regarding RCRA applicability when the EOR process ends or if the process becomes solely a geologic storage operation.[249]

6. <u>Geologic storage may be the greatest challenge to the adequate demonstration and development of CCS</u>

The complexity technical and financial uncertainties and concerns related to geologic storage are significant, and may represent the greatest barriers to the technical feasibility, adequate demonstration and commercialization of CCS. The availability of suitable saline formations, geologic injection pressure limitations, and the ultimate storage capacity of formations, as well as monitoring and verification methods are all currently the subject of intense study and lack large-scale data for proof-of-concept soundness. Unfortunately, EPA greatly downplays and ignores most of these issues in their BSER analysis.

A primary concern is with understanding the geology itself where characteristics may be highly variable even within a close area; where techniques to assess these characteristics are expensive and time consuming to perform; and where resources to evaluate such data through modeling or other means may not be able to adequately or reliably assess underground conditions. Consider, for example, the efforts to access the geology near the AEP Mountaineer Plant. From 2003 to 2007, over $7.5 million was spent to perform extensive surface and subsurface testing, including modeling and analyses, to characterize the geology near the plant

[249] 79 Fed. Reg. 355 (January 3, 2014).

and to assess its feasibility for $CO_2$ storage. Results provided sufficient information to support the development of the validation-scale[250] CCS project at the Mountaineer Plant. The validation-scale project included the development of additional wells for $CO_2$ injection and for monitoring purposes. Geologic data from characterization of these wells and the experience gained from operations greatly expanded the knowledge-base of the geology near the Mountaineer Plant.

Despite this extensive geologic knowledge obtained beginning with the initial characterization in 2003 and carried through the operation and monitoring of the validation facility, the information was insufficient to evaluate the geology and design the injection wells associated with the planned commercial-scale CCS program. Prior to the commercial-scale program being discontinued, one additional geologic characterization well was drilled approximately 3 miles from existing wells at the site. Even at this short distance, changes in the geologic characteristics were being noted that would have required a number of additional characteristic wells to be drilled had the project moved forward. At a cost of approximately $5 million per well and over 6 months to obtain the well works (drilling) permit, environmental-related permits, and conduct the drilling, obtaining these additional characteristics is not a small undertaking. Another potential concern is the availability of drilling contractors, in which a high demand exists by industries that are developing oil and gas resources. The opportunities from other industries can provide greater revenue potential and with less scrutiny. As one driller noted during the Mountaineer CCS Program, the demand for safety and environmental excellence by AEP, and presumably by other utilities, far exceeded that required by other industries and would not interest many potential drilling companies, especially if greater profits are available from those industries.

In addition, technologies to monitor and verify the location of the injected $CO_2$ are needed, whose capabilities, performance, and durability have not yet been proven for such applications. While experience from the oil exploration and production industries is beneficial, it is not a substitute for the lessons learned from operating a sufficient number of large-scale demonstration projects involving the injection of $CO_2$ in saline and other formations. Separately, a demand for more reliable geologically-based computer models remains, which, in part, requires a time-consuming, expensive, and rigorous validation process. If proven, these models could

[250] The AEP Mountaineer validation-scale project was designed to capture $CO_2$ from only 1.5% of the flue gas. It was not a commercial-scale project.

potentially be used to avoid exorbitantly high costs of installing and operating large numbers of monitoring wells, which otherwise may prohibit CCS development.[251]

The experiences of the Mountaineer CCS program are a further indication of the complexity at every level of developing injection wells in regards to technical, financial, and schedule risks. In the proposed rule, EPA seems to recognize this complexity by noting that:

> "*Geologic storage potential for $CO_2$ is widespread and available throughout the U.S...., each potential geologic sequestration site <u>must undergo appropriate site characterization</u> to ensure that the site can safely and securely store $CO_2$.*" (emphasis added)

and

> "*While EPA has confidence that geologic sequestration is technically feasible and available, <u>EPA recognizes the need to continue to advance the understanding</u> of various aspects of the technology, including, but not limited to, site selection and characterization, $CO_2$ plume tracking and monitoring.*" (emphasis added)

Despite this recognition, the agency fails to properly account for these design and development barriers in their evaluation of CCS as the BSER. Had EPA objectively considered the significant technical, financial, and practical barriers to the design of geologic storage areas, it would be clear that CCS is not the BSER.

7. <u>$CO_2$ pipeline development presents challenges to the adequate demonstration and development of CCS</u>

EPA gave minimal consideration to issues related $CO_2$ pipeline development. However, these issues pose a number of schedule, cost, and regulatory uncertainties that can be significant enough to eliminate the prospects of any CCS project. AEP experienced some of these pipeline development challenges in the initial design phase alone. For the commercial-scale (20% capture) Mountaineer Plant CCS project, AEP considered pipeline routes to potential injection wells located within 12 miles of the capture process. A common perspective is that pipeline routes could "simply" parallel existing transmission rights-of-way. AEP considered this option and found that it was anything but "simple." For example, existing transmission rights-of-way are commonly specific to above ground structures and would not apply to pipeline development. Further, existing rights-of-way do not always provide access to perform work that is not affiliated with the transmission lines.

[251] For example, it has been estimated that a cost risk of approximately $300 million may have been required to install the monitoring wells associated with a UIC Class VI injection well permit for the cancelled Mountaineer CCS Project that would have captured $CO_2$ from 20% of the flue gas.

This was the case for the AEP commercial-scale CCS project that planned to develop pipelines along existing transmission line corridors. In order to access potential pipeline routes for a visual assessment alone required obtaining additional rights-of-entry permissions from landowners. This additional permission was also necessary to perform baseline field studies (biological, cultural, and wetland) that were needed to develop applications for permits needed to facilitate construction. Obtaining this access was an onerous undertaking that increased the project cost and development timeline as over 250 landowners were involved. That process first involved extensive title searches to identify landowners, followed by an extensive outreach to contact landowners, who included local residents, businesses, out-of-state descendants, or yet-to-be probated estates. Many refused to grant access or did so after much inquiry. But this process reveals the complexity of what otherwise should have been a straight-forward and benign request – to *qualitatively* survey the existing transmission line right-of-way for a *potential* $CO_2$ pipeline and nothing more. Separate permissions would have had to be obtained to actually construct the pipeline, which undoubtedly would have been more challenging.[252] For capture projects that require much longer pipeline transport to access geologic storage or EOR systems, a developer would have obtain rights of way from potentially thousands of landowners and obtain permits from multiple jurisdictions, including multiple states. The scale of this effort would dwarf the aforementioned pipeline development challenges for the Mountaineer Plant CCS project.

Several entities have evaluated the cost for $CO_2$ pipeline development – and the estimates are staggeringly expensive. For example a 2007 Duke Energy study estimated that to construct a $CO_2$ pipeline along existing right of way from North Carolina to sites in the Gulf States and Appalachia would approach \$5 billion. Separately, the International Energy Agency concluded that a 50% reduction in $CO_2$ emissions by 2050 would require an investment of nearly \$300 billion to construct necessary pipelines to transport the $CO_2$ from capture to end use facilities.[253]

Another consideration with pipeline development is that its siting and design are dependent on the siting and design of the $CO_2$ injection wells. As discussed above, the site characterization, design, and permitting of the injection wells is also a time consuming process with considerable unknowns. Even though some preliminary pipeline development activities can

[252] "Bad Gas Policy." Peltier. R. Power Magazine. (Jul 2011). p. 6
[253] Id.

occur prior to and in parallel with the development of the injection wells, final pipeline design, permitting, and construction requires certainty on the location of the wells.

These types of challenges underscore the point that development of $CO_2$ transport systems will add significant scope, time, and cost to any CCS project. Although EPA ignores these challenges in the proposed rule, the impact of these risks should be evaluated in the final rule as EPA considers the overall feasibility and costs of CCS development.

8. <u>Enhanced oil recovery offers no guarantee as being available or willing to support $CO_2$ capture processes from coal-based generating units</u>

The EPA "*anticipates that many early geologic sequestration projects may be sited in active or depleted oil and reservoirs*" and that "*opportunities to utilize $CO_2$-EOR operations for geologic storage will continue to increase.*"[254] The agency also "*expects that for the immediate future, captured $CO_2$ from affected units will be injected underground for geologic sequestration at sites where EOR is occurring*."[255] The viability of these opportunities, however, faces many challenges, including those associated with the validation and accounting for $CO_2$ storage permanence. Current and past EOR practices have not been required to demonstrate permanent $CO_2$ storage. In some cases, EOR operators have been economically driven to minimize the quantity of $CO_2$ left underground in favor of reusing the injected $CO_2$ in other recovery operations. EPA also alludes to the lack of integrated power plant and EOR operating experience by noting that the "$CO_2$ supply for EOR operations currently is largely obtained from natural underground formations or domes that contain $CO_2$."[256] While EPA is optimistic that EOR applications will be the storage option of choice for future generators, the potential opportunities may be limited due to the proximity of EOR opportunities and the willingness of EOR operators to accept the operational risks and increased regulatory burdens that may come with the use and accounting of injected $CO_2$.

EOR operators are in the business of one thing – timely and cost-effectively producing hydrocarbons. They are not in the business of providing reliable, affordable electricity. They are not in the business of playing an integral role in the definition of a best system of emission reductions for another industry. EOR processes operate when and how they want to operate, outside the influence of electricity demand, power prices, or generation outages. EOR operators

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[254] 79 Fed. Reg. 1474. (January 8, 2014)
[255] 79 Fed. Reg. 1482. (January 8, 2014)
[256] 79 Fed. Reg. 1474. (January 8, 2014)

are only one component of a larger industry – an industry where competition and opportunities for development continue to expand, especially with the growth of hydraulic fracking and shale-gas extraction techniques. In other words, if the power industry through the use of carbon capture systems is able to provide another supply of $CO_2$ to support EOR operations that is cost-effective, then EOR operators *may* be willing use it. But it is not as if EOR operators are waiting in neutral or anxiously anticipating the possibility that power generation-derived $CO_2$ will become available, especially if the timetable for that availability is a significant unknown.

AEP has observed this type of ambivalence of one industry to another in working through the complex process of obtaining permission from coal companies to able to drill characterization, injection, and monitoring wells in support of the Mountaineer Plant CCS program – a program that could help lead to the continued use of the very product that such companies are producing, coal. In this example, the mineral rights below the surface of planned wells were owned by a coal company. Permission had to first be obtained from the owner to drill through the recoverable mineral, coal, before a well works (drilling) permit could be issued. Such permission was difficult to obtain and is another challenge to CCS development.

Regulatory challenges for EOR operators may be significant as well. Consider the October 2013 comments from U.S. EPA on the draft environmental impact statement for the proposed Hydrogen Energy California IGCC/CCS project. EPA's comments note that:

> ***"****According to the PSA/DEIS, hundreds of wells have been installed in the Elk Hills Oil Field for injection and production over the decades of petroleum extraction activity, as well as the thousands of well bores that abound in the site for different purposes and at varying depths of penetration... It indicates that the presence of such a large number of well bores in the seismically active project site creates a potential for leak pathways of injected $CO_2$... CEC staff recommends that HECA enter into an agreement with OEHI to require installation of a robust monitoring network capable of detecting leaks.*
>
> [EPA] *Recommendation: To the extent practicable, efforts should also be made to locate and permanently seal old wells that could provide a conduit for $CO_2$ leakage*."[257]

The prospect of being required to locate and permanently seal "hundreds of wells" and "thousands of well bores" is simply not practical, far outside the typical scope of EOR operations, and alone would likely doom any CCS project from being developed. As noted in the comments above, the EPA Class VI UIC permitting experience to date indicates that the

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[257] U.S. EPA Region IX Comments on Preliminary Staff Assessment/Draft EIS (CEQ#20130210) for HECA project. (October 24, 2013) . p. 12

process is time-consuming and the outcome of requirements is wrought with uncertainties. The time to obtain a Class VI UIC permit, perform detailed engineering and design, and construct a new fossil fuel-fired power plant equipped with CCS will encompass many years, and could easily require five to seven years or more. Aligning such a lengthy and uncertain development time frame with the business plans of an EOR operator represents a significant challenge to any CCS project. EPA has been extremely naive in assuming that the EOR experience to date could readily accommodate the requirement to install CCS technologies on fossil-fuel based generating units. For example, as EPA notes in the proposed rule:

> "*A recent study by DOE found that the market for captured $CO_2$ emissions from power plants created by economically feasible $CO_2$-EOR projects would be sufficient to permanently store the $CO_2$ emissions from 93 large (1,000 MW) coal-fired power plants operated for 30 years*."[258]

Such optimism clearly escapes another DOE report that indicates the EOR experience to date cannot be assumed to be sufficient to readily accommodate regulated CCS technologies. This report was authored by Dr. James Dooley and others at the Pacific Northwest National Laboratories ("PNNL") – the same author and organization that prepared a separate evaluation of CCS, which EPA draws upon in the technical feasibility portion of their BSER analysis. Several statements in the PNNL EOR report are particularly noteworthy and suggest that EOR opportunities are not readily available to support power plant CCS systems, including:[259]

- "*$CO_2$-EOR as commonly practiced today does not meet the emerging regulatory thresholds for $CO_2$ sequestration, and considerable effort and costs may be required to bring current practice up to this level*." (p. 5)
- "[O]*ur research suggest that $CO_2$-EOR is dissimilar enough from true commercial-scale CCS – the vast majority of configurations likely to deploy – that it is unlikely to significantly accelerate large scale adoption of the technology*" (p.3)
- "*The paper concludes....that estimates of the cost of $CO_2$-EOR production or the extent of $CO_2$ pipeline networks based upon this energy security-driven promotion of $CO_2$-EOR do not provide a robust platform for spurring the commercial deployment of carbon dioxide capture and storage technologies (CCS) as a means of reducing greenhouse gas emissions.*" (p. 2)
- "*The authors remain skeptical of arguments for expanded $CO_2$-EOR that are, at their core, extrapolations of what happened in the past in an effort to address energy*

[258] 79 Fed. Reg. 1474. (January 8, 2014)
[259] "$CO_2$-driven Enhanced Oil Recover as a Stepping Stone to What?". Dooley, et.al. Pacific Northwest National Laboratory. (July 2010). PNNL-19557.

*security concerns, a fundamentally different motivation than stabilizing atmospheric concentrations of GHGs*." (p.16)

- "*The vast majority of $CO_2$-EOR projects inject $CO_2$ produced from natural underground accumulations; in the U.S. and Canada, naturally-sourced $CO_2$ provides an estimated 83% of the $CO_2$ injected for EOR*" (p. 4)

- "*The requirements necessary to qualify $CO_2$-EOR as a geosequestration project are not trivial and involve significant work and cost throughout each state of the project*." (p. 10)

- "*The fact that only one of the 129 current $CO_2$-EOR projects worldwide is regarded or certified as a CCS project, and only 1 of the 4 current commercial CCS projects utilizes the $CO_2$-EOR process, provide significant empirical evidence that $CO_2$-EOR is not a mandatory step on the path to CCS deployment*." (p. 27)

Separately, the proposed rule relies upon current GHG reporting programs to help demonstrate compliance. The reporting tools upon which EPA is relying have never been used. For calendar year 2012, only two facilities submitted any information to EPA's GHG Reporting Program for carbon injection activities.[260] Both of these facilities have been granted research and development exemptions for GHG reporting, and both of them reported only the volume of GHGs received at the facility under subpart UU, not the detailed information required by subpart RR. There were no estimates of the amounts of GHGs actually successfully sequestered, and neither facility has developed the kind of monitoring protocols required under subpart RR. The remaining facilities listed in EPA's reporting tool are only subject to subpart UU, and are only required to report volumes of "new" $CO_2$ received at the facility, not the amounts that are used in, recovered, and recycled through EOR or other operations, nor any amounts that may be emitted from those operations. As a result, no useful information about the actual amounts of $CO_2$ in recovered oil and gas, or emitted to the surface in connection with an EOR operation, has ever been submitted to EPA. Indeed, based on the 2012 reports, it appears that the other 85 facilities listed as being subject to subpart UU required no "new" $CO_2$ for their operations during the entire year, leading one to question the availability of EOR opportunities for the large amounts of $CO_2$ that would be captured at even a single, partially controlled coal-fired steam generating unit. EPA therefore has no basis for its assumptions regarding the availability of

[260] www.epa.gov/climate/ghgreporting/ghgdata/reported/index.html

sequestration at EOR operations, or the ability of such operators to successfully design a monitoring program that would meet the requirements of subpart RR.

9. Extensive permitting requirements introduces significant schedule and financial challenges to the development of CCS technologies

Permitting related challenges to the viability of any CCS project, include:

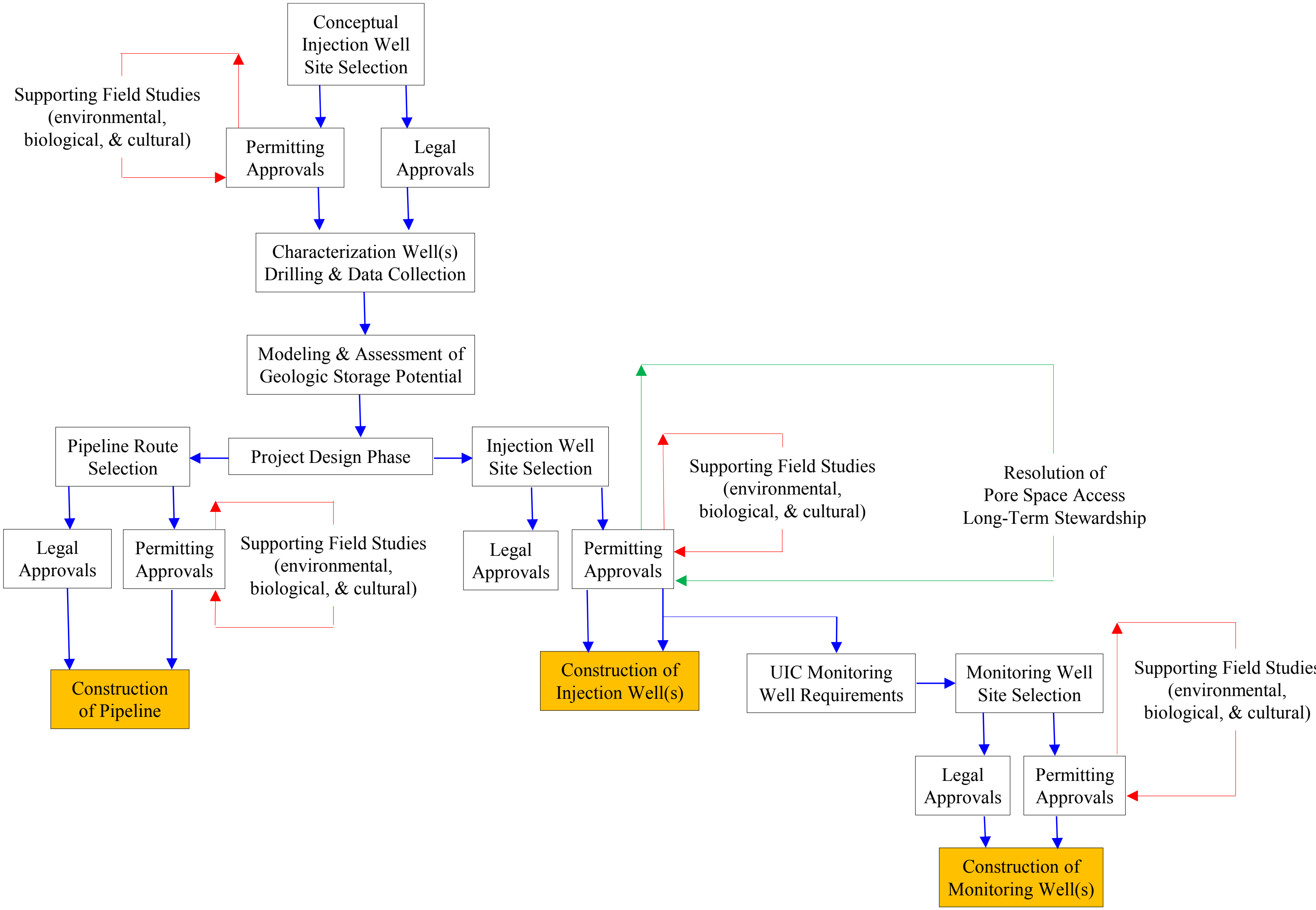
- The size of the CCS project alone (capture, transport, and storage systems) requires extensive field studies to evaluate biological, cultural, and wetland resources to support the preparation of permit applications;

- The complexity of issues involved with developing a CCS project falls under the jurisdiction of many regulatory agencies. This adds significant complexity in regards to coordinating overlapping and, at times, conflicting requirements between agencies;

- Inexperience in permitting CCS related issues by the developer and the regulator adds time to the application and permit development process, as well as uncertainty in the stringency of the final requirements;

The challenges significantly impact project schedule and finances. The figure below provides context on these issues related just to pipeline and well development. Each step within this process not only adds scope and time to the project, but also comes with uncertainty in regards to various regulatory approvals and pitfalls that may result from field studies and construction activities. Simply, the permitting process for the pipeline and well aspects of a CCS project alone could take *years* to resolve before construction could even begin.

**Example of Permitting Complexity for CCS Projects**



### D. EPA's rationale for eliminating full capture CCS as the BSER is equally applicable to partial capture CCS

EPA eliminated full capture CCS as the BSER for fossil fuel-fired boilers and IGCC units based only one reason – cost. As EPA notes:

> "*We previously indicated that the costs - $147/MWh for the new SCPC unit* [with full capture CCS] *and $136/MWh for the new IGCC unit* [with full capture CCS] – *are not reasonable and we rejected that option as BSER on that basis.*"[261]

and

> "*These* [full capture CCS] *costs exceed what project developers have been willing to pay for other low GHG-emitting base load generating technologies... For that reason alone, we do not believe that the costs of full implementation of CCS are reasonable at this time.*"[262]

AEP agrees that on the basis of cost alone, full capture CCS is not the BSER. In addition on the basis of any number of technical, financial, regulatory, or practical considerations, alone or collectively, full capture CCS is not the BSER. Nonetheless, EPA's rationale for eliminating full capture CCS would be <u>much stronger</u> if the agency considered the more realistic cost estimates for full and partial capture that have been experienced by actual projects (including the very project examples that EPA references in the proposed rule). EPA's determination would also be strengthened if the consideration was given to the cost estimates developed by other major assessments (including the type of major assessments that EPA discusses in the proposed rule as being necessary to evaluate complex issues that require judgment).

If "*for* [these] *reason*[s] *alone*,"[263] EPA rejects full capture as the BSER, then the higher cost range identified by the experience of projects to date and more comprehensive major assessments clearly indicates that <u>neither full capture CCS, nor partial capture CCS is the BSER</u> for fossil fuel-fired boiler and IGCC units.

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261 79 Fed. Reg. 1478. (January 8, 2014).
262 79 Fed. Reg. 1477. (January 8, 2014).
263 Id.

The following contrasts the types of CCS-related cost escalations that EPA relies upon in their analysis of the BSER:

**EPA Cost Analysis of CCS Technologies[264]**

| Unit | Configuration | LCOE $/MWh | CCS Related Cost Increase | EPA Conclusion |
|---|---|---|---|---|
| SCPC | No CCS | 92 | --- | --- |
| SCPC | Partial CCS, No EOR | 110 | 20% | Justifies partial capture as the BSER |
| SCPC | Full, 90% CCS | 147 | 60% | Too expensive. Full capture eliminated as BSER |
| IGCC | No CCS | 97 | --- | --- |
| IGCC | Partial CCS, No EOR | 109 | 12% | Justifies partial capture as the BSER |
| IGCC | Full, 90% CCS | 136 | 40% | Too expensive. Full capture eliminated as BSER |

When compared to the experiences of actual projects and the assessments from organizations that much more thoroughly follow and are directly involved in CCS development issues, EPA's cost assessment misses the mark by a very wide margin both in terms of the magnitude of costs involved and with respect to the current state of CCS development. Others have reached different conclusions regarding the cost of CCS. For example:

- On February 11, 2014, Deputy Assistant Secretary of Energy Dr. Julio Friedmann testified that first generation carbon capture technology on coal-based generating plants will increase the cost of electricity by 70 to 80%.[265]
- In 2013, the Global CCS Institute estimated first-of-a-kind CCS would increase the cost of electricity by 61 to 76% for post-combustion processes and 37% for IGCC units.[266]
- 2010 DOE/NETL CCS Roadmap estimated CCS will add 80% to the cost of a new pulverized coal plant and 35% to the cost of a new IGCC plant.[267]

EPA's range of a 12 to 60% cost increase for CCS is far below the aforementioned estimates of DOE and others that approach 80% or more. EPA eliminated full capture CCS as the BSER on the sole basis that it would be too expensive (40 to 60% cost increase).[268] The 40-60% cost increase that EPA estimates for full capture CCS

- "does not meet the cost criterion of BSER"[269];
- "is outside the range of costs...and should not be considered BSER"[270];

[264] 79 Fed. Reg. 1476 (January 8, 2014)
[265] Friedmann, J. Oral Testimony before U.S. House of Representatives Committee on Energy and Commerce. (Feb 11, 2014)
[266] "The Global Status of CCS: 2013". (Oct 2013). Global CCS Institute. p 172.
[267] DOE / NETL $CO_2$ Capture and Storage RD&D Roadmap. (Dec 2010). p. 10
[268] 79 Fed. Reg. 1477. (January 8, 2014).
[269] 79 Fed. Reg. 1497. (January 8, 2014).

- "are not reasonable and...[are] rejected....as BSER on that basis.[271]"

If the 40-60% increase was sufficient to eliminate full capture, then the 80+% cost increase that has been experienced by active projects and that has been estimated by DOE and others is **more than sufficient** to eliminate partial and full capture as the BSER.

**E. EPA's rationale for eliminating CCS as the BSER for the natural gas combustion turbine source category is equally applicable to CCS for fossil fuel-fired boilers and IGCC units**

EPA correctly eliminated partial and full capture CCS as the BSER for natural gas fired-combustion turbines ("NGCT") based on technical feasibility concerns. Much of EPA's rationale in eliminating CCS for NGCT's is equally applicable to coal-based generation units as well. In regards to technical feasibility, EPA correctly cites the lack of sufficient information and industry experience to eliminate CCS as the BSER by noting for example:

> "*CCS has not been implemented for NGCC units, and we believe there is insufficient information regarding the technical feasibility of implementing CCS at these types of units.*"[272]
>
> "*The EPA is not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard.*"[273]
>
> "*EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units.*"[274]
>
> "*Adding CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements. The cyclical operation, combined with the already low concentrations of $CO_2$ in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC.*"[275]
>
> "*It is unclear how part-load operation and frequent startup and shutdown evens would impact the efficiency and reliability of CCS. We are not aware that any of the pilot-scale CCS projects have operated in a cycling mode. Similarly, none of the larger CCS*

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[270] 79 Fed. Reg. 1435. (January 8, 2014).
[271] 79 Fed. Reg. 1478. (January 8, 2014).
[272] 79 Fed. Reg. 1436. (January 8, 2014). (emphasis added)
[273] Id. (emphasis added)
[274] Id. (emphasis added)
[275] Id. (emphasis added)

*projects being constructed, or under development, are designed to operate in a cycling mode.*"[276]

To summarize, CCS was eliminated as the BSER for natural gas combustion turbines because:

- CCS "has not been implemented on NGCC units";
- No CCS demonstrations have occurred on NGCC units that "would justify setting a national standard"; and
- "insufficient information" is available to assess the "transfer" of CCS experience from other industries, the performance of CCS under "typical NGCC" operating conditions, and the technical feasibility of CCS for NGCT's.

In order to address these issues, the agency indicated that more information is needed from "*larger scale demonstration projects on units operating more like a typical NGCC*." Such information would be essential to evaluate technical concerns, as well as financial, regulatory, and other uncertainties.

AEP agrees with the technical concerns identified by EPA eliminate CCS as the BSER. AEP also agrees that large-scale demonstration projects (note plural as identified by EPA) are a key aspect of any strategy to address these concerns, and that such large-scale demonstration projects have not yet occurred on any NGCC process. However, as discussed throughout our comments, these same concerns **are equally, if not more applicable** to the application of CCS to coal-based generating units. AEP is greatly troubled that EPA has applied a double-standard for evaluating CCS for coal-based generation and natural gas-fired combustion turbine units.

As an example of the agency's double standard in evaluating CCS for each source category consider how the $CO_2$ capture experience of the natural gas and other industries is characterized and applied in the BSER analysis for each. In the BSER analysis for coal-based generation, EPA's discussion of this experience includes:

- "*Capture of $CO_2$ from industrial gas streams has occurred since the 1930's*"[277]
- "*These* [$CO_2$ capture] *processes have been used in the natural gas industry*"[278]
- "[T]*here are currently twenty-three industrial source CCS projects in twelve states that are either operational, under-construction, or actively being pursued which are or will supply captured $CO_2$ for the purposes of EOR.*"[279]
- "*Each of the core components of CCS – $CO_2$ capture, compression, transportation, and storage – has already been implemented*"[280]

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[276] Id. 1485. (emphasis added)
[277] Id. 1471.
[278] Id.
[279] Id. 1474

- "*The U.S. experience with large-scale $CO_2$ injection..., combined with ongoing CCS research, development, and demonstration programs in the U.S. and throughout the world provide confidence that capture, transport, compression and storage...can be achieved.*"[281]

EPA **avoids discussion** of this broader industrial CCS experience in their BSER analysis for NGCT units – even though that experience is noted to have occurred within the natural gas industry and in processes similar to NGCT units. In fact, the extent of EPA's discussion of CCS experience in the BSER analysis for NGCT units is as follows:

> "*The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream.*"[282] This "*one demonstration project....is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.*"[283]

The agency provides no details or citations for this single CCS project on an NGCC unit,. The proposed rule does not even mention the name of the facility! While this one project alone was not a commercial-scale integrated $CO_2$ capture and geologic storage project, and as a result is not compelling enough to conclude that CCS is the BSER, the operating experience and lessons learned should have at least been evaluated by the agency. The CCS project that EPA references was a carbon capture process installed at the Northeast Energy Associates Bellingham Plant – a natural gas combined cycle plant located in Bellingham, Massachusetts. From 1991 to 2004, the plant operated a $CO_2$ capture system that captured 365 short tons/day of $CO_2$,[284] which was stored in tanks onsite and trucked as necessary to a nearby food processing industry (approximately 106,000 tonnes/year[285]). As the capacity factor of the plant declined, it became uneconomical to continue operation of the capture system.

EPA clearly made little, if any, attempt to understand and learn from this experience as suggested by the agency's characterization of the effort as being a "demonstration project." However, a system that operates for 14 years and is shutdown due to market conditions is far from a demonstration project, even if it was not a commercial-scale capture project and did not include integrated pipeline and storage systems. The Bellingham Plant used the Econamine FG capture process – a process that has been applied to over 23 commercial plants to recover $CO_2$

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280 Id. 1471.
281 Id.
282 Id. 1436.
283 Id. 1485
284 Fluor's Econamine FG Plus[SM] Technology For $CO_2$ Capture at Coal-fired Power Plants. Satish Reddy, et al. Presented at Power Plant Air Pollutant Control "Mega" Symposium. (Aug 2008). Baltimore, Md. pp 3-4.
285 Final Report of the Interagency Task Force on CCS. (Aug 2010). p. A-2

from flue gas associated with natural gas combustion – <u>none of which</u> represent commercial-scale NGCC $CO_2$ capture projects integrated with pipeline and geologic storage systems.[286]

A review of the "extensive literature record" on CCS was included in the BSER evaluation of technical feasibility for coal-based units, which consisted of only three documents that EPA in turn used to support their position on CCS for coal-based units. The BSER for NGCT units **does not** include any literature review. Coincidently, two of the three documents relied upon in the BSER evaluation for coal-based units discuss the experience of CCS systems on natural gas combustion turbines. The Report of the Interagency Task Force on CCS that EPA references includes a list of natural gas power plants and combustion sources that are equipped with carbon capture systems.[287] The Pacific Northwest National Laboratory report that EPA relies upon has a section devoted to the experience of carbon capture systems on natural gas power plants, which includes two facilities that use Econamine capture systems similar to the Bellingham Plant that EPA ambiguously references in the proposed rule.[288] The report also notes that "*$CO_2$ has been captured...from natural gas power plants since the early 1990s*."[289] While none of these reports reference commercial-scale NGCC $CO_2$ capture projects integrated with pipeline or geologic storage systems, it is noteworthy that these examples were ignored entirely even though the experience is much broader than for coal-based electric generation units.

In fact, an evaluation of these CCS experiences on natural gas combustion turbines and the prospects of applying this experience to future NGCC process is non-existent in EPA's BSER for NGCT units. Ironically, even though the Econamine capture system that has been used by NGCC processes **has yet to be demonstrated on a single coal-based generating unit**, EPA assumes in its cost analysis for the BSER that new pulverized coal units with CCS will be equipped with the Econamine system.

So if 14 years of experience using the Econamine capture process at one NGCC unit, along with years of related experience at other natural gas-fired facilities is not worthy of consideration, yet alone mention, within the BSER analysis for NGCT units, then how can the fictional use of that same Econamine capture process, which has never been demonstrated on a

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[286] Fluor's Econamine FG Plus[SM] Technology: An Enhanced Amine-Based $CO_2$ Capture Process. Satish Reddy, et al. Presented at the Second National Conference on Carbon Sequestration. NETL/DOE. May 2003. p. 2.

[287] Final Report of the Interagency Task Force on CCS. Aug 2010. p. A-2

[288] "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. Pacific Northwest National Laboratory. Dooley, et.al. PNNL-18520. (Jun 2009). See Section 4.4 "Post-Combustion $CO_2$ capture from Natural Gas-fired Facilities". p. 10.

[289] Id. p.8

single coal-based unit, carry a shred of weight in evaluating the technical feasibility or potential costs of CCS for coal-based units? Obviously, the answer is that it cannot and the fact that EPA's reliance on the use of this capture system is further evidence that EPA's BSER analysis for coal-based generation units is flawed and its determination of partial CCS as the BSER has no credibility.

### F. EPA's BSER determination is flawed because it does not consider all source types within the source category

For the natural gas combustion turbine source category, EPA relied upon a variety of technical, operational, and other factors to conclude that CCS is not the BSER. These include the low concentration of $CO_2$ in natural gas combustion streams, frequency of load change, and a lack of commercially demonstrated CCS. These same factors are applicable to and even more pronounced with the operation of natural gas-fired boiler generating units. However, EPA gave zero consideration to these issues for natural gas boilers. Instead, the focus of EPA's evaluation of CCS as the BSER for fossil fuel boilers is solely on coal-based generating units. Therefore, in regards to natural gas-fired boiler generating units (as well as for coal-based units as discussed elsewhere in our comments), EPA has proposed an NSPS that, by EPA's own logic for combustion turbines, is not technically feasible and has not been adequately demonstrated.

## X. Highly Efficient Generating Technologies are the BSER for Fossil-Fuel Fired Boilers and IGCC Units

### A. EPA has not objectively evaluated highly efficient generation technologies and has prematurely eliminated this option as the BSER

EPA's analysis of highly efficient generating technologies is woefully inadequate and has the strong appearance of being, at best, nothing more than a hastily prepared and clumsily executed box-checking exercise that:

- does not "provid[e] the EPA greater assurance that it is basing its judgment on the best available, well-vetted science" [290];
- does not "address the scientific issues that the Administrator must examine" [291];
- does not "represent the current state of knowledge on the key elements" [292]; and

[290] Id. 1456.
[291] Id. 1440.
[292] Id. 1440.

- does not attempt to "comprehensively cover [or] obtain the majority conclusions from the body of scientific literature.[293]"

For example, EPA's evaluation of highly efficient technologies made

- no attempt to define highly efficient technologies;
- no attempt to understand or articulate the key variables that impact efficiency;
- no attempt to assess the prospects of developing solutions to reduce the impacts from these key variables on unit efficiency;
- no attempt to identify or assess the operation of highly efficient generation technologies domestically or internationally as the agency attempted with CCS;
- no attempt to quantify the potential emission reductions associated with the use of highly efficient generation technologies; and
- no attempt to assess the overall environmental benefits of highly efficient generation technologies compared to CCS technologies.

It is noteworthy that EPA's entire evaluation of highly efficient new generation is **less than one page** of the 90 page Federal Register version of the propose rule.[294] Yet, based on this evaluation, EPA decides to "*not consider them* [e.g. highly efficient generation without CCS] *to qualify as the BSER for the following reasons: (a) Lack of Significant $CO_2$ Reductions*...[and] *(b) Lack of Incentive for Technological Innovation.*"[295] Both reasons are invalid.

Consider again EPA's analogy that compares the BSER determination process to that of determining the "best baseball player," both of which involve a "complex weighing of several criteria" based on an "exercise of judgment."[296] EPA's evaluation of highly efficient generating technologies is equivalent to determining who is the "best baseball player" by simply looking at players in a team picture, while ignoring individual statistics, performance on the field, players on other teams, or up and coming player prospects.

Unfortunately, EPA has also ignored the significant progress that continues to be made around the world in developing and operating more efficient coal-based generation technologies. The same DOE/NETL report that EPA relies upon throughout the evaluation of CCS as the BSER discusses these efficiency improvements **on the very first page**:

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[293] Id. 1440.
[294] 79 Fed Reg. pp. 1468-1469. Section B.1 "Highly Efficient New Generation Without CCS Technology" (January 8, 2014).
[295] 79 Fed Reg. 1468. (January 8, 2014)
[296] 79 Fed. Reg. 1466. (January 8, 2014)

> "*The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with* <u>*great improvements in efficiency*</u>*...*"[297]

With the value that EPA placed on extensively using this report in the evaluation of CCS as the BSER, it is unclear how this promising insight on the recent experience and future prospects of efficiency improvements could have been overlooked or failed to at least piqued EPA's interest in thoroughly investigating efficiency opportunities, especially because EPA notes that its "crucial to take initial steps now to limit GHG emissions from fossil fuel-fired power plants."[298] EPA's lack of interest in seriously evaluating highly efficient generating technologies is even more surprising because the agency has evaluated such technologies in depth at least three times in recent years in the following reports:

- March 2011: "PSD and Title V Permitting Guidance for Greenhouse Gases" U.S. EPA;
- October 2010: "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units" U.S. EPA; and
- July 2006: "Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies" U.S. EPA.

Collectively, these EPA reports

- determined site-specific drivers that impact unit efficiency
- assessed design opportunities for efficiency improvements
- reviewed ultra-supercritical boiler technologies
- identified and discussed specific domestic and international projects that are utilizing and advancing the development of higher efficient coal generation technologies

In addition, the 2010 report states that EPA was developing a publicly-accessible database of GHG mitigation technologies. It was noted that the "database is a tool that provides information on both commercially available technologies, as well as emerging technologies that are being demonstrated at larger scales for commercial viability."[299] At least as of 2011, EPA was progressing on the development of the database and was actively presenting updates and discussion beta versions at various conferences.[300]

[297] Cost and Performance Baseline for Fossil Energy Plants. Vol.1. Rev.2a. NETL. Sept 2013. p.v. (emphasis added)
[298] 79 Fed Reg. 1433. (January 8, 2014)
[299] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA. (Oct 2010). p. 40
[300] www.epa.gov/air/caaac/pdfs/1_11_GMOD_CAAAC.pdf (Accessed Feb 21, 2014)

Alarmingly, none of this extensive information was utilized or even referenced in EPA's less than one page evaluation of highly efficient generation technologies. It is unclear why EPA completely ignores this information, as consideration of these reports and other related information would clearly indicate that highly efficient generation technologies are the BSER.

**B. Highly efficient generating technologies are technically feasible**

Even though EPA determines that highly efficient generation processes are technically feasible, the agency makes no attempt to identify such technologies or to understand the levels of performance that currently are or have the potential to be achievable. Instead, EPA cavalierly determines that "*supercritical or ultra-supercritical coal-fired boilers or IGCC units...are clearly technically feasible*" with zero context.[301]

At present, ultra-supercritical technology represents the most efficient design option available for coal-fired boilers. However, the proposed rule does not provide a serious, objective evaluation of the technology, and in fact mentions "ultra-supercritical" *only* five times, two of which are found in a footnote the states:

> "*Ultra-supercritical (USC) and advanced ultra-supercritical (A-USC) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.*"[302]

That is the extent EPA's discussion on ultra-supercritical technologies. EPA does not attempt, even qualitatively, to evaluate the availability, experience, or prospects of ultra-supercritical technology. EPA implies that advanced-ultrasupercritical might be a better option than USC, but offers no distinction or additional information. In fact, the aforementioned footnote is the **only time** that the term "advanced ultra-supercritical" appears in the entire rule. It is as if EPA by the use of the phrase "terms often used" dismisses higher efficiency processes as being common-place, inconsequential technologies that are fully mature and have no prospects for growth, which is far from reality. Ultra-supercritical technologies are only beginning to emerge as a cost-effective design preference for new coal-based generation projects. For example, the first ultra-supercritical pulverized coal unit in the U.S. began operating in 2012, the world's first supercritical circulating fluidized bed coal unit began operating in 2009 in Poland, and the first USC CFB units are currently being developed.

[301] 79 Fed. Reg. 1435. (January 8, 2014).
[302] 79 Fed. Reg. 1468. (January 8, 2014).

Currently, research and development of advanced-USC (i.e. generation technologies that approach 50% or greater efficiency) is showing strong promise and near-term prospects are widely recognized. A summary of perspectives on advanced-ultrasupercritical technologies follows that should prompt EPA to perform a complete assessment of these technologies in its evaluation of highly efficient generation technologies:

| Source: | Perspective on Advanced-USC Technologies |
|---|---|
| World Coal Association | "Research and development is under way for ultra-supercritical units operating at even higher efficiencies, potentially up to around 50%"[303] |
| Babcock & Wilcox<br>Power Generation Group | "The technical viability of A-USC is being demonstrated in the development programs of new alloys" and "Design concepts for advanced ultra-supercritical steam generators are being developed."[304] |
| International Energy Association<br>"Technology Roadmap for High-Efficiency, Low-Emissions Coal-Fired Power Generation" | "Development of A-USC aims to achieve efficiencies in excess of 50%"... "Efforts to develop advanced USC technology could lower emissions (a 30% improvement). Deployment of advanced USC is expected to begin within the next 10 to 15 years"[305] |
| US DOE, Ohio Coal Development, EPRI<br>"Boiler Materials for Ultrasupercritical Coal Power Plants" | "a project aimed at identifying, evaluating, and qualifying the materials needed for the construction of the critical components of coal-fired boilers capable of operating at much higher efficiencies.. This increased efficiency is expected to be achieved principally through the use of advanced ultrasupercritical (A-USC) steam conditions."[306, 307] |

It is clear that significant development strides have been made and are actively being pursued to advance the efficiency of coal-based generation technologies. Competition from other generation technologies and regulatory drivers will continue to drive these efforts. The fact that EPA has completely dismissed the potential of these technologies is a clear indication that the agency had no intention to objectively consider higher efficiency generation technologies, regardless of the benefits or opportunities such technologies could provide as part of an overall GHG reduction strategy. Not only has EPA ignored the potential for higher efficiency generating units, but also EPA has made no attempt to understand the successful experience of projects using these technologies all around the world.

For example, the AEP Turk Plant is the first ultra-supercritical pulverized coal generating unit in the U.S. Since beginning commercial operations in 2012, the Turk Plant has

[303] www.worldcoal.org/coal-the-environment/coal-use-the-environment/improving-efficiencies/
[304] www.babcock.com/library/Documents/BR-1852.pdf
[305] www.iea.org/publications/freepublications/publication/TechnologyRoadmapHighEfficiencyLowEmissionsCoalFiredPowerGeneration_Updated.pdf
[306] www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022037
[307] www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Jeffrey%20Phillips%20-%20EPRI%20-%203-24-11.pdf

demonstrated superior performance with respect to increased unit efficiency, reduced auxiliary power demand, lower emissions profiles, and a lower overall environmental footprint. Operations at the Turk Plant represent significant advancements that are a foundation for even greater advancements *if given the opportunity*. A conventional supercritical unit operates at steam temperatures of 1,000 – 1,050°F, while an ultra supercritical (USC) unit operates at steam temperatures grater than 1,100°F. Steam conditions for the Turk Plant are 1,110°F (main steam) and 1,125°F (reheat steam). By operating at these higher steam temperatures, the turbine cycle is more efficient, which in turn reduces fuel (coal) consumption and thereby reduces emissions, combustion byproducts, and water demand. Historically, the utility industry has been reluctant to move to USC technologies due to operational risks, availability, and reliability concerns. However, developments in advanced materials technologies have addressed many of these concerns and now allows for better performing and more affordable piping and turbine components that can withstand higher temperatures.

Despite the performance to date and the prospects for advanced ultra-supercritical designs, EPA gives <u>only one passing reference</u> to the Turk Plant in the proposed rule. Given the accomplishments represented by Turk and the potential that it has to set the standard for new generation, it would only be reasonable to think that EPA would thoroughly and proactively evaluate and consider the opportunities and potential of such technology in their BSER analysis. However EPA made no attempt to even begin to understand AEP's experience at the Turk Plant in terms of the design, performance, and opportunities it represents for ultra-supercritical technology. AEP would welcome such a dialogue and invites EPA to tour the Turk Plant to expand their knowledge of USC technology and to strengthen their BSER evaluation.

In the consideration of CCS as the BSER, EPA referenced <u>**nine**</u> international projects and databases listing <u>**dozens**</u> of other international efforts related to various aspects of CCS development. But in the evaluation of highly efficient generating technologies as the BSER, EPA referenced <u>**zero**</u> projects although significant efforts are occurring worldwide that have been widely recognized. The table below summarizes some of these efforts, which should prompt EPA to perform a complete assessment of these technologies in their evaluation of highly efficient generation technologies. Ironically, information on four of the projects comes from a 2010 EPA Report that evaluates available and emerging technologies for reducing GHG emissions from coal-fired generating units – a report that EPA ignores in the proposed rule.

| International Project: | Comments: |
|---|---|
| Lagisza Power Plant (Poland) [308] | World's first supercritical CFB unit<br>Commenced operations in 2009 |
| Lunen Power Plant (Germany) [309] | "Most Efficient...Coal-fired Power Plant in Europe)<br>Commenced operations in December, 2013 |
| Manjung Plant (Malaysia) [310] | 1,000 MW ultra-supercritical plant<br>Commence Construction in 2014 /Operations in 2017 |
| Isogo Plant[311] (Japan) | 600 MW ultra-supercritical plant<br>Commenced Operation in 2009 |
| Niederaussem Power Station (Germany) [312] | 965 MW ultra-supercritical plant<br>Commenced operation in 2002 |
| Nordjylland Power Plant (Denmark) [313] | 384 MW ultra-supercritical plant<br>Commenced operation in 1998 |

In regards to IGCC processes, EPA has incorrectly portrayed the maturity and performance of the technology. While IGCC is technically feasible, it has not been adequately demonstrated. This is evidenced by the experiences of the only two commercial-scale IGCC projects under construction and commissioning in the U.S.: Kemper and Edwardsport. Both represent a FOAK integration and scale-up of process components. Both have experienced significant cost escalations throughout their design and construction and neither has been demonstrated to be equivalent or more efficient than other coal-based generation technologies. These factors are indicative of a technology that is early in its development cycle. In addition, the number of cancelled IGCC projects due to technical and financial issues is more evidence that the technology is far from being fully developed. For example, a NETL database indicates at least 16 potential IGCC projects have been cancelled in the U.S. in recent years.[314]

Further, no pilot-, validation-, or commercial-scale CCS process has been demonstrated with an IGCC process. The IGCC process alone faces significant development risks and barriers to being adequately demonstrated and commercialized. Aside from the Kemper project, which has yet-to-be-constructed and does not have a $CO_2$ limit or CCS operating requirements within its air permit, the integration of CCS into the IGCC process will add significant complexity and

[308] www.powermag.com/operation-of-worlds-first-supercritical-cfb-steam-generator-begins-in-poland/
[309] www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2013/energy/power-generation/ep201312013.htm
[310] www.sumitomocorp.co.jp/english/news/detail/id=27067
[311] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units." U.S. EPA. (Oct 2010). p. 31
[312] Id.
[313] Id
[314] www.netl.doe.gov/research/coal/energy-systems/gasification/gasification-plant-databases

risks that would make future IGCC projects prohibitive. EPA ignores these risks and barriers completely in the BSER analysis and incorrectly relies upon fictional IGCC performance and cost information that is premised on vendor estimates of future, fully mature processes that have never been constructed and that have certainly not been demonstrated. Therefore, any analysis, including the evaluation of the BSER, is flawed that relies upon such information to assess cost-effectiveness and emission reductions, or to establish the standard that would apply to all coal-based generation technologies.

### C. Highly efficient generating technologies are cost effective

Despite the many flaws in its evaluation of technical feasibility and the lack of quantitative or even a credible qualitative analysis, EPA concludes that high efficiency generating technologies should not be eliminated as the BSER on the basis of cost. AEP agrees that certain highly efficient generating technologies are cost effective as evidenced by the number of projects that are being successfully completed worldwide. The difference between the initial and final costs of these projects is not significant in many cases, which is also representative of technology that has matured beyond FOAK projects. In fact, many of these projects have been financed without a dependence on government subsidies, another sign of the lower risk and confidence of such technology advancements.

In regards to IGCC, any cost estimates for future projects are speculative at best due to the early stage of development. The two IGCC projects under active construction and commissioning in the U.S. are both FOAK processes and have both experienced significant cost escalations throughout their development. It is premature to utilize the experience of these projects to estimate the cost of future IGCC projects. In addition, there is zero value in EPA's cost-analysis that ignores these active projects and relies upon vendor estimates of never constructed IGCC units.

### D. Highly efficient generating technologies provide meaningful emission reductions, and have less overall environmental impacts compared to CCS systems

#### 1. EPA incorrectly downplays and dismisses the emission reductions that may be achieved by highly efficient generating technologies

EPA quickly eliminates highly efficient generation technologies because "*they do not provide meaningful reductions in $CO_2$ emissions from new sources.*"[315] EPA is incorrect. Without any attempt to credibly evaluate current or future performance capabilities, the agency simply discredits any benefits that may be realized by noting that:

> "*Efficiency-improvement technologies alone result in only very small reductions (several percent) in $CO_2$ emissions, especially in contrast to those achieved by the application of CCS.*"[316]

EPA provides no explanation of the criteria for determining "meaningful reductions" or "very small reductions," other than that such reductions are not the same as the potential reductions from CCS technologies. Because EPA provides no analysis that even begins to quantify the magnitude of potential emission reductions from more efficient technologies, the agency is in no position to assume "only very small reductions" are possible. The agency also provides no analysis of the magnitude of emission reductions that may be realized with the development of more advanced technologies whose optimistic prospects are widely recognized. The following sections provide such an evaluation using data from EPA's own databases, to demonstrate that the development of highly efficient generation technologies has historically, is presently, and will continue in the future to set new standards for providing for significant emission reductions from coal-based generating units.

#### 2. The development of highly efficient generation technologies continues to provide meaningful emission reductions

Throughout the history of coal-based electric generation, the development and implementation of higher efficiency generation technologies has occurred that has enhanced operations, increased reliability, reduced emissions, and minimized other environmental impacts. A review of emissions data contained in the EPA's Clean Air Market Division ("CAMD") database highlights these historical trends.

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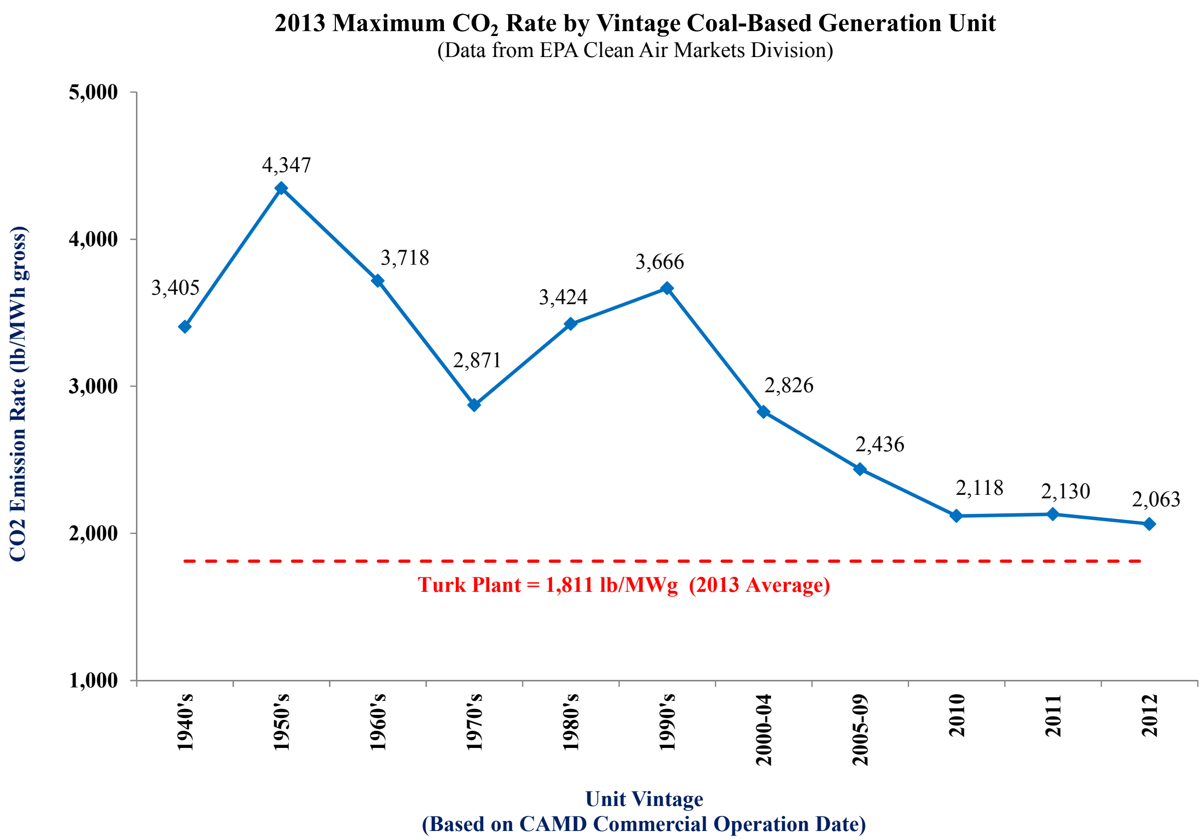
[315] 79 Fed. Reg. 1435. (January 8, 2014)
[316] Id.

The CAMD database was accessed to obtain the following for all coal-based generating units in the U.S: 2013 annual $CO_2$ emissions, 2013 gross generation data, and the commercial operating date of each unit.[317] A total of 820 coal-based generating units were identified with sufficient information to compute $CO_2$ emission rates (pounds per gross megawatt hours) for comparison.[318] The 820 units were then grouped by the decade that they commenced operation beginning with 1940's vintage units. A more refined grouping was made of units that have commenced operation since 2000. The maximum $CO_2$ emission rate was then calculated for each vintage of units and compared to the 2013 performant of the AEP Turk Plant. Results are summarized below.




[317] CAMD data per http://ampd.epa.gov/ampd (May 1, 2014).

[318] Id. Derivation of 820 units: 3,602 in database. 943 units with coal as the "primary fuel." 121 units eliminated due to insufficient data. 2 units eliminated primarily fired natural gas in 2013. Thus, 943 units – 121 - 2 = 820 units.

The figure depicts the significant technological advancements that have been and continue to be achieved that improve process efficiencies and lower the $CO_2$ emission rate of next generation coal-based generating technologies. The maximum emission rates trend lower over the time period, which is indicative that greater efficiencies are being realized across a number of different coal types and combustion technologies. The historical improvements in $CO_2$ emission rates would be expected to continue with the emergence of higher efficiency technologies that are currently being developed.

3. <u>A BSER determination based on high efficient generation technologies alone would produce significant emission reductions</u>

EPA is incorrect to assume that efficiency improvements offer little potential for significant emission reductions. An analysis of 2013 emissions data from the EPA's CAMD database indicates an NSPS based on the best performing existing unit would yield significant $CO_2$ reductions in new units. For example, consider the 42 coal-based generating units that have commenced operation after 2000. If these units were to be constructed today to achieve a GHG NSPS limit derived from the best performing existing units, significant $CO_2$ reductions would occur. The 2013 CAMD database contained 820 coal units with sufficient emission data to include in the analysis.[319] Expanding the hypothetical scenario above towards replacing entire existing U.S. coal fleet would reduce greater than 100 million tons of $CO_2$ annually. The table below summarizes $CO_2$ reductions assuming each of these units meets various hypothetical NSPS standards:

[319] Id.

| | Total Units | 2013 CAMD CO2 (tons) | 2013 CAMD Generation (MWh gross) | 2013 Average CO2 Rate (lb/MWg) | Hypothtical CO2 Tons at a rate of 1,850 lb/MWg | Hypothtical CO2 Tons at a rate of 1,800 lb/MWg | Hypothtical CO2 Tons at a rate of 1,775 lb/MWg |
|---|---|---|---|---|---|---|---|
| Coal Units that began operation after 2000 | 42 | 125,981,368 | 129,611,577 | 1,944 | 119,890,709 | 116,650,420 | 115,030,275 |
| | **Hypothetical CO2 Reductions from 2013 CAMD** | | | | 6,090,659 | 9,330,949 | 10,951,093 |

| | Total Units | 2013 CAMD CO2 (tons) | 2013 CAMD Generation (MWh gross) | 2013 Average CO2 Rate (lb/MWg) | Hypothtical CO2 Tons at a rate of 1,850 lb/MWg | Hypothtical CO2 Tons at a rate of 1,800 lb/MWg | Hypothtical CO2 Tons at a rate of 1,775 lb/MWg |
|---|---|---|---|---|---|---|---|
| All 2013 CAMD coal-units | 820 | 1,678,393,342 | 1,657,369,741 | 2,025 | 1,533,067,010 | 1,491,632,767 | 1,470,915,645 |
| | **Hypothetical CO2 Reductions from 2013 CAMD** | | | | 145,326,332 | 186,760,575 | 207,477,697 |

To provide context on the types of benefits that higher efficiency technologies could provide consider the Turk Plant is the first and only coal-based generation unit in the U.S. that employs ultra supercritical technology. The 2013 CAMD database identified 819 additional existing coal-based generation units (e.g., not including the Turk Plant). Assume that all of these units are retired and that their capacity is replaced with a coal-based generating unit that is *at least* equivalent to the Turk Plant in terms of efficiency and emission rates. Such a scenario would yield the following for the same capacity generated in 2013 by these existing units:[320]

- Reduced $CO_2$ emissions: 177,000,000 tons (11% reduction)
- Reduced $SO_2$ emissions: 2,755,000 tons (88% reduction)
- Reduced $NO_x$ emissions: 1,232,000 tons (81% reduction)

In addition, replacing these existing 819 units, many of which have a smaller design capacity compared to the 600 MW Turk design, would only require approximately 400 new units. Generating the same capacity with less than half the number of units would greatly simplify the magnitude of development, construction, permitting, and permitting related considerations. Such a scenario would preserve the benefits and value of maintaining the role of coal as part of a balanced energy portfolio for the U.S. Rather than prohibit future coal-based

[320] Id.

generation units, the aforementioned scenario would enable even more advanced generation and emission control systems, including CCS, to be developed, demonstrated, and commercialized.

4. Highly efficient generation technologies provide greater overall environmental benefits compared to CCS technologies

The overall environmental benefits of higher efficiency generation technologies are superior to those afforded by CCS technologies. For example, higher efficiency technologies utilize less coal, water, and raw materials (i.e. ammonia for $NO_x$ removal, limestone for $SO_2$ removal, etc.) to generate the same amount of electricity compared to lower efficiency processes, including those might be equipped with CCS systems. This significantly increases auxiliary load and reduces the overall output of the process. In other words, for a given generating unit designed to meet a specific demand capacity, that unit would have to be significantly oversized to accommodate the increased auxiliary power requirements of CCS technology. The end result of this oversized design is the need to utilize more coal, water, and raw materials with the result being more emissions, wastewater, and combustion byproducts.

**E. Determining highly efficient generating technologies are the BSER would promote technology development**

EPA eliminates highly efficient technologies as the BSER, in part, because such a standard would "*not advance the development and implementation of control technologies to reduce $CO_2$ emissions*" and "*does not develop control technology that is transferrable to existing EGUs*."[321] EPA is incorrect and fails to offer even a basic quantitative or qualitative analysis to support their position.

An NSPS based on the adequately demonstrated performance of the most efficient operating units would absolutely drive future innovation, such as the development of units that use alternative combustion technologies or coal types that could also meet the standard. It would also accelerate the advancement of technologies that provide a greater compliance margin below the NSPS, increased operating flexibility, and reduced development risks. Further, it is expected that the development of efficiency improvement technologies could be transferred to existing EGUs. Such efficiency-based improvements certainly would be more readily transferred to existing units than CCS technologies, which are handicapped with significant integration, financial, regulatory, and siting challenges that simply could not be accommodated by the

[321] 79 Fed. Reg. 1469. (January 8, 2014).

existing fleet. In any event, it is not clear that the consideration of technology transfer to existing sources is a necessary metric that EPA should weigh in determining the BSER.

In addition, EPA eliminates highly efficient technologies because they do not "*promote the development of generation technologies that would minimize the auxiliary load and cost of future CCS requirement*" and because "*such a standard could impede the advancement of CCS technology*."[322] Is EPA proposing an NSPS based on the use of the BSER, or is EPA proposing a CCS development rule? For the reasons presented in other sections, CCS is clearly not the BSER. Actually, the further development of highly efficient technologies could actually benefit the development of CCS. Nonetheless, the development of more efficient technologies that require less auxiliary load and that generate less $CO_2$ per output would be beneficial for any new coal-based unit, regardless of whether CCS is included in the design.

As noted in the comments on technical feasibility, significant progress is being achieved on the development of higher efficiency generating technologies. In addition, it is widely recognized that significant opportunities remain for the development of even more advanced generation technologies and that such development will continue to set new standards for unit efficiency for all types of coal-based generation technologies.

### F. EPA should establish an NSPS subcategory that is specific to IGCC as these processes are fundamentally different from other coal generation technologies

#### 1. IGCC technology is not a one-size-fits-all process design

The term IGCC represents a broad range of process designs that incorporate varying gasification technologies, syngas cleanup methods, power generation strategies, and other plant systems. The scope of process differences reflects the impact of coal quality variables on design features, as well as the immaturity of the technology. The design and performance of IGCC units that are operating or under construction are not representative of all IGCC technologies.

NETL has been actively involved in IGCC development for decades and maintains an extensive library of information on gasification and related technologies. The following from NETL highlights some of the different IGCC design options that are being developed.

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[322] 79 Fed. Reg. 1469. (January 8, 2014).

## Gasification Technologies[323]

Gasification involves the oxidation of coal into a syngas that can be used for power generation or processed into synthetic fuels or chemical feedstocks. Design options include the method of coal injection into the gasifier (dry-feed or slurry-feed) and the type of oxidant used (oxygen or air). Gasifiers can be broadly classified into three categories (entrained-flow, fluidized-bed, and fixed-bed). Various gasifier technologies are summarized below, each has its own unique set of design and operating variables:

| Gasifier Category | Gasifier Design | Coal Feed to Gasifier | Oxidant | IGCC Units in the U.S. |
|---|---|---|---|---|
| Entrained-Flow | GE Energy | Slurry-Feed | Oxygen-Blown | Polk<br>Edwardsport |
| Entrained-Flow | CB&I E-Gas | Slurry-Feed | Oxygen-Blown | Wabash |
| Entrained-Flow | Shell | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | Siemens | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | PRENFLO | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | MHI | Dry-Feed | Air-Blown | none |
| Entrained-Flow | EAGLE | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | HCERI | Dry-Feed | Oxygen-Blown | none |
| Entrained-Flow | ECUST | Slurry-Feed<br>Dry-Feed | Oxygen-Blown | none |
| Fluidized-Bed | KBR Transport | Dry-Feed | Air-Blown<br>Oxygen-Blown | Kemper |
| Fluidized-Bed | High Temp Winkler | Dry-Feed | Air-Blown<br>Oxygen-Blown | none |
| Fluidized-Bed | U-GAS | Dry-Feed | Air-Blown<br>Oxygen-Blown | none |
| Fluidized-Bed | Great Point Energy | Dry-Feed | Catalytic Gasification | none |
| Fixed-Bed | Lurgi | Dry-Feed | Oxygen-Blown | none |
| Fixed-Bed | British Gas Lurgi | Dry-Feed | Oxygen-Blown | none |

323 www.netl.doe.gov/File%20Library/Research/Coal/energy%20systems/gasification/gasifipedia/index.html (Accessed Apr 14, 2014)

## Syngas Cleanup Systems

A range of syngas cleanup systems have been identified by NETL, most of which have not been demonstrated on a commercial-scale IGCC unit. These systems can be categorized as particulate removal systems, acid-gas removal systems, and other syngas cleanup processes.

**IGCC Particulate Removal Systems**[324]

| Category | Process |
|---|---|
| dry particulate removal | cyclone technology |
| dry particulate removal | candle filters |
| wet particulate removal | water scrubbing |

**IGCC Acid Gas Removal Systems**[325]

| AGR System | Solvent |
|---|---|
| Chemical Solvents | Primary Amines |
| Chemical Solvents | Secondary Amines |
| Chemical Solvents | Tertiary Amines |
| Chemical Solvents | Potassium Carbonate |
| Physical Solvents | Selexol |
| Physical Solvents | Rectisol |
| Physical Solvents | Purisol |
| Mixed Solvents | Sulfinol-D |
| Mixed Solvents | Sulfinol-M |
| Mixed Solvents | Flexsorb SE/SB |
| Mixed Solvents | Amisol |

**Other IGCC Syngas Cleanup Systems**[326]

| Category | System |
|---|---|
| Sulfur Recover & Tail Gas Treatment | Claus Process |
| Sulfur Recover & Tail Gas Treatment | SCOT Tail Gas Treatment |
| Sulfur Recover & Tail Gas Treatment | Sulfuric Acid Synthesis |
| Sulfur Recover & Tail Gas Treatment | Potassium Carbonate |
| Syngas Cleanup System | COS Hydrolysis |
| Syngas Cleanup System | Water Gas Shift |
| Syngas Cleanup System for Mercury | Activated Carbon |

[324] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/particulate-removal (Accessed Apr 14, 2014)
[325] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/agr (Accessed Apr 14, 2014)
[326] www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/sulfur-recovery (Accessed Apr 14, 2014)

Power Generation Strategies

Design options are available for IGCC that can impact the emissions profile for the unit. The first is fuel selection as units may be designed and operated to accommodate a range of feedstocks to the gasifier that could be blended with coal. With respect to the combustion turbines, design considerations include the type (manufacture and vintage) of turbine deployed, co-firing options with natural gas, the use of low $NO_x$ burner technologies and/or water injection. In regards to the heat recovery steam generator (HRSG), consideration includes duct-firing capabilities and the use of SCR or oxidation catalyst technologies, which to date have yet to be demonstrated on a coal-based IGCC unit. The future use of hydrogen-based combustion turbines will also impact the emissions profile. In addition, the design of IGCC processes is often integrated with poly-generation options, which expands the purpose of these facilities beyond power generation and which further supports the need for an IGCC specific subcategory.

Summary

In summary, a suite of IGCC design options are being developed for a variety of coal types and operating scenarios. To date, IGCC technology has been demonstrated at only two units in the U.S., with two other units coming online in the near future. The design of these four facilities represents only a fraction of the coal-based IGCC process configurations that could be used in the future. These facilities represent FOAK technologies and their performance and capabilities present significant risks and uncertainties. The use of CCS technologies would introduce another level of integration risk and operational uncertainty. As a result, the efficiency and $CO_2$ rates for these IGCC processes is to be determined and warrants establishing a separate NSPS subcategory that is specific to IGCC units.

2. An NSPS subcategory specific to IGCC should be established to address the unique design and operation of these processes

IGCC processes are inherently different from other methods of coal-based electric generation and more similar to natural gas combined cycle units. Coal-derived $CO_2$ emissions can be emitted from a number of processes within the IGCC unit depending on the operating scenario. In addition, coal-based $CO_2$ emissions can be commingled with the $CO_2$ emissions from other fuels consumed by various IGCC systems. Because of these unique operating and design characteristics, a separate NSPS subcategory specific to IGCC should be established. Issues that this subcategory would have to consider include:

- operating scenarios when coal-based syngas is not consumed by the combustion turbines, but by other process systems, such as a flare, thermal oxidizer, etc.
- operating scenarios when the combustion turbines are firing only natural gas or co-firing natural gas and coal-based syngas
- operating scenarios when the combustion turbines are consuming coal-based syngas and natural gas is combusted in duct burners in the heat recovery steam generator
- operating scenarios when coal and other carbonaceous compounds (petcoke, biomass, municipal solid waste, etc.) are simultaneously being gasified to produce a syngas
- combustion turbines that use synthetic natural gas (coal-based syngas) that is produced offsite by another facility

**G. EPA has incorrectly assessed the performance capabilities of new coal-based generating technologies that are designed with CCS**

EPA uses a single NETL report[327] from 2010 to assess the performance capabilities of new coal-based generation technologies.[328] This report was discredited at length in comments above regarding the flawed CCS cost analysis performed by the agency. Likewise, the report is unreliable for assessing the performance of highly efficient generation technologies due to (i) a narrow reliance on dated vendor supplied conceptual designs for coal-based generation technologies that have **never** been constructed, operated, or proven; and (ii) an evaluation that is restricted to generation technologies that only use bituminous coals, with **no consideration** given to the use of lower rank coals.

In fact, no data has been found that validates the related emission rates from this report that EPA purports has been or are capable of being demonstrated. EPA blindly accepts the information without any consideration of the actual performance of operating units. Such operating data is readily available through the EPA Clean Air Markets Division (CAMD) database. At a minimum, EPA should thoroughly analyze operating data from the CAMD database to inform their assessment of what emission rates are being demonstrated in practice. The agency should then expand this analysis by engaging operators, vendors, and equipment manufactures to evaluate performance drivers and to determine emission rates that are representative and sustainable for various coal-based generation technologies.

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327 Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010)
328 79 Fed. Reg. 1468 (January 8, 2014)

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| AMEA Sylacauga Plant | Alabama | 56018 | 1 | 9 | 9 |
| AMEA Sylacauga Plant | Alabama | 56018 | 2 | 9 | 9 |
| Barry | Alabama | 3 | 1 | 61 | 61 |
| Barry | Alabama | 3 | 2 | 41 | 41 |
| Barry | Alabama | 3 | 3 | | |
| Barry | Alabama | 3 | 4 | 518 | 518 |
| Barry | Alabama | 3 | 5 | 1,073 | 1,073 |
| Barry | Alabama | 3 | 6A | 29 | 29 |
| Barry | Alabama | 3 | 6B | 31 | 31 |
| Barry | Alabama | 3 | 7A | 27 | 27 |
| Barry | Alabama | 3 | 7B | 26 | 26 |
| Calhoun Power Company I, LLC | Alabama | 55409 | CT1 | 13 | 13 |
| Calhoun Power Company I, LLC | Alabama | 55409 | CT2 | 11 | 11 |
| Calhoun Power Company I, LLC | Alabama | 55409 | CT3 | 13 | 13 |
| Calhoun Power Company I, LLC | Alabama | 55409 | CT4 | 11 | 11 |
| Charles R Lowman | Alabama | 56 | 1 | 52 | 52 |
| Charles R Lowman | Alabama | 56 | 2 | 432 | 432 |
| Charles R Lowman | Alabama | 56 | 3 | 442 | 442 |
| Colbert | Alabama | 47 | 1 | | |
| Colbert | Alabama | 47 | 2 | | |
| Colbert | Alabama | 47 | 3 | | |
| Colbert | Alabama | 47 | 4 | | |
| Colbert | Alabama | 47 | 5 | | |
| Colbert | Alabama | 47 | CCT1 | 0 | 0 |
| Colbert | Alabama | 47 | CCT2 | 1 | 1 |
| Colbert | Alabama | 47 | CCT3 | 0 | 0 |
| Colbert | Alabama | 47 | CCT4 | 0 | 0 |
| Colbert | Alabama | 47 | CCT5 | 0 | 0 |
| Colbert | Alabama | 47 | CCT6 | 0 | 0 |
| Colbert | Alabama | 47 | CCT7 | 0 | 0 |
| Colbert | Alabama | 47 | CCT8 | 0 | 0 |
| Decatur Energy Center | Alabama | 55292 | CTG-1 | 23 | 23 |
| Decatur Energy Center | Alabama | 55292 | CTG-2 | 20 | 20 |
| Decatur Energy Center | Alabama | 55292 | CTG-3 | 22 | 22 |
| Discover | Alabama | 55138 | 1A | 2 | 2 |
| Discover | Alabama | 55138 | 1B | 2 | 2 |
| Discover | Alabama | 55138 | 2A | 2 | 2 |
| Discover | Alabama | 55138 | 2B | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| E B Harris Generating Plant | Alabama | 7897 | 1A | 32 | 32 |
| E B Harris Generating Plant | Alabama | 7897 | 1B | 30 | 30 |
| E B Harris Generating Plant | Alabama | 7897 | 2A | 28 | 28 |
| E B Harris Generating Plant | Alabama | 7897 | 2B | 26 | 26 |
| E C Gaston | Alabama | 26 | 1 | 301 | 301 |
| E C Gaston | Alabama | 26 | 2 | 316 | 316 |
| E C Gaston | Alabama | 26 | 3 | 309 | 309 |
| E C Gaston | Alabama | 26 | 4 | 280 | 280 |
| E C Gaston | Alabama | 26 | 5 | 1,606 | 1,606 |
| Gadsden | Alabama | 7 | 1 | 83 | 83 |
| Gadsden | Alabama | 7 | 2 | 28 | 28 |
| Gorgas | Alabama | 8 | 6 | | |
| Gorgas | Alabama | 8 | 7 | | |
| Gorgas | Alabama | 8 | 8 | 202 | 202 |
| Gorgas | Alabama | 8 | 9 | 156 | 156 |
| Gorgas | Alabama | 8 | 10 | 1,306 | 1,306 |
| Greene County | Alabama | 10 | 1 | 397 | 397 |
| Greene County | Alabama | 10 | 2 | 406 | 406 |
| Greene County | Alabama | 10 | CT10 | 4 | 4 |
| Greene County | Alabama | 10 | CT2 | 5 | 5 |
| Greene County | Alabama | 10 | CT3 | 6 | 6 |
| Greene County | Alabama | 10 | CT4 | 4 | 4 |
| Greene County | Alabama | 10 | CT5 | 4 | 4 |
| Greene County | Alabama | 10 | CT6 | 4 | 4 |
| Greene County | Alabama | 10 | CT7 | 5 | 5 |
| Greene County | Alabama | 10 | CT8 | 4 | 4 |
| Greene County | Alabama | 10 | CT9 | 4 | 4 |
| Hillabee Energy Center | Alabama | 55411 | CT1 | 37 | 37 |
| Hillabee Energy Center | Alabama | 55411 | CT2 | 37 | 37 |
| Hog Bayou Energy Center | Alabama | 55241 | COG01 | 27 | 27 |
| James H Miller Jr | Alabama | 6002 | 1 | 856 | 856 |
| James H Miller Jr | Alabama | 6002 | 2 | 860 | 860 |
| James H Miller Jr | Alabama | 6002 | 3 | 906 | 906 |
| James H Miller Jr | Alabama | 6002 | 4 | 976 | 976 |
| McIntosh (7063) | Alabama | 7063 | **1 | 3 | 3 |
| McIntosh (7063) | Alabama | 7063 | **2 | 8 | 8 |
| McIntosh (7063) | Alabama | 7063 | **3 | 6 | 6 |
| McIntosh (7063) | Alabama | 7063 | **4 | 12 | 12 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| McIntosh (7063) | Alabama | 7063 | **5 | 7 | 7 |
| McWilliams | Alabama | 533 | **4 | 45 | 45 |
| McWilliams | Alabama | 533 | **V1 | 28 | 28 |
| McWilliams | Alabama | 533 | **V2 | 34 | 34 |
| Morgan Energy Center | Alabama | 55293 | CT-1 | 22 | 22 |
| Morgan Energy Center | Alabama | 55293 | CT-2 | 21 | 21 |
| Morgan Energy Center | Alabama | 55293 | CT-3 | 24 | 24 |
| Plant H. Allen Franklin | Alabama | 7710 | 1A | 30 | 30 |
| Plant H. Allen Franklin | Alabama | 7710 | 1B | 27 | 27 |
| Plant H. Allen Franklin | Alabama | 7710 | 2A | 28 | 28 |
| Plant H. Allen Franklin | Alabama | 7710 | 2B | 27 | 27 |
| Plant H. Allen Franklin | Alabama | 7710 | 3A | 33 | 33 |
| Plant H. Allen Franklin | Alabama | 7710 | 3B | 33 | 33 |
| SABIC Innovative Plastics - Burkville | Alabama | 7698 | CC1 | 50 | 50 |
| Tenaska Central Alabama Gen Station | Alabama | 55440 | CTGDB1 | 33 | 33 |
| Tenaska Central Alabama Gen Station | Alabama | 55440 | CTGDB2 | 30 | 30 |
| Tenaska Central Alabama Gen Station | Alabama | 55440 | CTGDB3 | 30 | 30 |
| Tenaska Lindsay Hill | Alabama | 55271 | CT1 | 23 | 23 |
| Tenaska Lindsay Hill | Alabama | 55271 | CT2 | 121 | 121 |
| Tenaska Lindsay Hill | Alabama | 55271 | CT3 | 21 | 21 |
| Theodore Cogeneration | Alabama | 7721 | CC1 | 26 | 26 |
| Washington County Cogen (Olin) | Alabama | 7697 | CC1 | 104 | 104 |
| Widows Creek | Alabama | 50 | 1 | | |
| Widows Creek | Alabama | 50 | 2 | | |
| Widows Creek | Alabama | 50 | 3 | | |
| Widows Creek | Alabama | 50 | 4 | | |
| Widows Creek | Alabama | 50 | 5 | | |
| Widows Creek | Alabama | 50 | 6 | | |
| Widows Creek | Alabama | 50 | 7 | | |
| Widows Creek | Alabama | 50 | 8 | | |
| Carl Bailey | Arkansas | 202 | 01 | 36 | 26 |
| Cecil Lynch | Arkansas | 167 | 2 | | |
| Cecil Lynch | Arkansas | 167 | 3 | 118 | 86 |
| City Water & Light - City of Jonesboro | Arkansas | 56505 | SN04 | 20 | 14 |
| City Water & Light - City of Jonesboro | Arkansas | 56505 | SN06 | 24 | 17 |
| City Water & Light - City of Jonesboro | Arkansas | 56505 | SN07 | 19 | 15 |
| Dell Power Plant | Arkansas | 55340 | 1 | 17 | 17 |
| Dell Power Plant | Arkansas | 55340 | 2 | 18 | 18 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Flint Creek Power Plant | Arkansas | 6138 | 1 | 1,332 | 965 |
| Fulton | Arkansas | 7825 | CT1 | 14 | 14 |
| Hamilton Moses | Arkansas | 168 | 1 | | |
| Hamilton Moses | Arkansas | 168 | 2 | | |
| Harry D. Mattison Power Plant | Arkansas | 56328 | 1 | 21 | 21 |
| Harry D. Mattison Power Plant | Arkansas | 56328 | 2 | 19 | 18 |
| Harry D. Mattison Power Plant | Arkansas | 56328 | 3 | 12 | 12 |
| Harry D. Mattison Power Plant | Arkansas | 56328 | 4 | 9 | 9 |
| Harvey Couch | Arkansas | 169 | 1 | | |
| Harvey Couch | Arkansas | 169 | 2 | 17 | 12 |
| Hot Spring  Energy Facility | Arkansas | 55418 | CT-1 | 28 | 28 |
| Hot Spring  Energy Facility | Arkansas | 55418 | CT-2 | 21 | 21 |
| Hot Spring Power Co., LLC | Arkansas | 55714 | SN-01 | 37 | 37 |
| Hot Spring Power Co., LLC | Arkansas | 55714 | SN-02 | 38 | 38 |
| Independence | Arkansas | 6641 | 1 | 1,840 | 1,333 |
| Independence | Arkansas | 6641 | 2 | 2,017 | 1,461 |
| John W. Turk Jr. Power Plant | Arkansas | 56564 | SN-01 | 322 | 322 |
| Lake Catherine | Arkansas | 170 | 1 | 0 | 0 |
| Lake Catherine | Arkansas | 170 | 2 | 0 | 0 |
| Lake Catherine | Arkansas | 170 | 3 | 1 | 1 |
| Lake Catherine | Arkansas | 170 | 4 | 256 | 186 |
| McClellan | Arkansas | 203 | 01 | 108 | 78 |
| Oswald Generating Station | Arkansas | 55221 | G1 | 26 | 22 |
| Oswald Generating Station | Arkansas | 55221 | G2 | 19 | 19 |
| Oswald Generating Station | Arkansas | 55221 | G3 | 24 | 21 |
| Oswald Generating Station | Arkansas | 55221 | G4 | 14 | 14 |
| Oswald Generating Station | Arkansas | 55221 | G5 | 19 | 17 |
| Oswald Generating Station | Arkansas | 55221 | G6 | 18 | 16 |
| Oswald Generating Station | Arkansas | 55221 | G7 | 18 | 18 |
| Pine Bluff Energy Center | Arkansas | 55075 | CT-1 | 108 | 108 |
| Plum Point Energy Station | Arkansas | 56456 | 1 | 690 | 690 |
| Robert E Ritchie | Arkansas | 173 | 2 | | |
| Thomas Fitzhugh | Arkansas | 201 | 2 | 53 | 45 |
| Union Power Station | Arkansas | 55380 | CTG-1 | 27 | 27 |
| Union Power Station | Arkansas | 55380 | CTG-2 | 26 | 26 |
| Union Power Station | Arkansas | 55380 | CTG-3 | 32 | 32 |
| Union Power Station | Arkansas | 55380 | CTG-4 | 30 | 30 |
| Union Power Station | Arkansas | 55380 | CTG-5 | 27 | 27 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Union Power Station | Arkansas | 55380 | CTG-6 | 26 | 26 |
| Union Power Station | Arkansas | 55380 | CTG-7 | 32 | 32 |
| Union Power Station | Arkansas | 55380 | CTG-8 | 29 | 29 |
| White Bluff | Arkansas | 6009 | 1 | 2,116 | 1,533 |
| White Bluff | Arkansas | 6009 | 2 | 2,130 | 1,544 |
| AL Sandersville | Georgia | 55672 | CT1 | 1 | 1 |
| AL Sandersville | Georgia | 55672 | CT2 | 1 | 1 |
| AL Sandersville | Georgia | 55672 | CT3 | 0 | 0 |
| AL Sandersville | Georgia | 55672 | CT4 | 0 | 0 |
| AL Sandersville | Georgia | 55672 | CT5 | 1 | 1 |
| AL Sandersville | Georgia | 55672 | CT6 | 1 | 1 |
| AL Sandersville | Georgia | 55672 | CT7 | 0 | 0 |
| AL Sandersville | Georgia | 55672 | CT8 | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1A | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1B | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1C | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1D | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1E | 0 | 0 |
| Allen B Wilson Combustion Turbine Plant | Georgia | 6258 | 1F | 0 | 0 |
| Baconton | Georgia | 55304 | CT1 | 7 | 7 |
| Baconton | Georgia | 55304 | CT4 | 7 | 7 |
| Baconton | Georgia | 55304 | CT5 | 7 | 7 |
| Baconton | Georgia | 55304 | CT6 | 7 | 7 |
| Bowen | Georgia | 703 | 1BLR | 376 | 376 |
| Bowen | Georgia | 703 | 2BLR | 424 | 424 |
| Bowen | Georgia | 703 | 3BLR | 550 | 550 |
| Bowen | Georgia | 703 | 4BLR | 556 | 556 |
| Bowen | Georgia | 703 | 6A | 0 | 0 |
| Bowen | Georgia | 703 | 6B | 0 | 0 |
| Chattahoochee Energy Facility | Georgia | 7917 | 8A | 27 | 27 |
| Chattahoochee Energy Facility | Georgia | 7917 | 8B | 25 | 25 |
| Dahlberg (Jackson County) | Georgia | 7765 | 1 | 8 | 8 |
| Dahlberg (Jackson County) | Georgia | 7765 | 2 | 3 | 3 |
| Dahlberg (Jackson County) | Georgia | 7765 | 3 | 9 | 9 |
| Dahlberg (Jackson County) | Georgia | 7765 | 4 | 10 | 10 |
| Dahlberg (Jackson County) | Georgia | 7765 | 5 | 9 | 9 |
| Dahlberg (Jackson County) | Georgia | 7765 | 6 | 4 | 4 |
| Dahlberg (Jackson County) | Georgia | 7765 | 7 | 8 | 8 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Dahlberg (Jackson County) | Georgia | 7765 | 8 | 3 | 3 |
| Dahlberg (Jackson County) | Georgia | 7765 | 9 | 9 | 9 |
| Dahlberg (Jackson County) | Georgia | 7765 | 10 | 4 | 4 |
| Doyle Generating Facility | Georgia | 55244 | CTG-1 | 4 | 4 |
| Doyle Generating Facility | Georgia | 55244 | CTG-2 | 5 | 5 |
| Doyle Generating Facility | Georgia | 55244 | CTG-3 | 4 | 4 |
| Doyle Generating Facility | Georgia | 55244 | CTG-4 | 6 | 6 |
| Doyle Generating Facility | Georgia | 55244 | CTG-5 | 5 | 5 |
| Effingham County Power, LLC | Georgia | 55406 | 1 | 29 | 29 |
| Effingham County Power, LLC | Georgia | 55406 | 2 | 25 | 25 |
| Hammond | Georgia | 708 | 1 | 28 | 28 |
| Hammond | Georgia | 708 | 2 | 38 | 38 |
| Hammond | Georgia | 708 | 3 | 39 | 39 |
| Hammond | Georgia | 708 | 4 | 150 | 150 |
| Harllee Branch | Georgia | 709 | 1 | 101 | 101 |
| Harllee Branch | Georgia | 709 | 2 | 104 | 104 |
| Harllee Branch | Georgia | 709 | 3 | 135 | 135 |
| Harllee Branch | Georgia | 709 | 4 | 211 | 211 |
| Hartwell Energy Facility | Georgia | 70454 | MAG1 | 8 | 8 |
| Hartwell Energy Facility | Georgia | 70454 | MAG2 | 8 | 8 |
| Hawk Road Energy Facility | Georgia | 55141 | CT1 | 16 | 16 |
| Hawk Road Energy Facility | Georgia | 55141 | CT2 | 19 | 19 |
| Hawk Road Energy Facility | Georgia | 55141 | CT3 | 26 | 26 |
| Jack McDonough | Georgia | 710 | 3AA | 0 | 0 |
| Jack McDonough | Georgia | 710 | 3AB | 0 | 0 |
| Jack McDonough | Georgia | 710 | 3BA | 0 | 0 |
| Jack McDonough | Georgia | 710 | 3BB | 0 | 0 |
| Jack McDonough | Georgia | 710 | 4A | 36 | 36 |
| Jack McDonough | Georgia | 710 | 4B | 37 | 37 |
| Jack McDonough | Georgia | 710 | 5A | 56 | 56 |
| Jack McDonough | Georgia | 710 | 5B | 57 | 57 |
| Jack McDonough | Georgia | 710 | 6A | 35 | 35 |
| Jack McDonough | Georgia | 710 | 6B | 34 | 34 |
| Jack McDonough | Georgia | 710 | MB1 | 135 | 135 |
| Jack McDonough | Georgia | 710 | MB2 | 135 | 135 |
| Kraft | Georgia | 733 | 1 | 42 | 42 |
| Kraft | Georgia | 733 | 2 | 43 | 43 |
| Kraft | Georgia | 733 | 3 | 20 | 20 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Kraft | Georgia | 733 | 4 | 0 | 0 |
| McIntosh (6124) | Georgia | 6124 | 1 | 19 | 19 |
| McIntosh (6124) | Georgia | 6124 | CT1 | 2 | 2 |
| McIntosh (6124) | Georgia | 6124 | CT2 | 1 | 1 |
| McIntosh (6124) | Georgia | 6124 | CT3 | 0 | 0 |
| McIntosh (6124) | Georgia | 6124 | CT4 | 1 | 1 |
| McIntosh (6124) | Georgia | 6124 | CT5 | 1 | 1 |
| McIntosh (6124) | Georgia | 6124 | CT6 | 1 | 1 |
| McIntosh (6124) | Georgia | 6124 | CT7 | 1 | 1 |
| McIntosh (6124) | Georgia | 6124 | CT8 | 1 | 1 |
| McIntosh Combined Cycle Facility | Georgia | 56150 | 10A | 22 | 22 |
| McIntosh Combined Cycle Facility | Georgia | 56150 | 10B | 21 | 21 |
| McIntosh Combined Cycle Facility | Georgia | 56150 | 11A | 23 | 23 |
| McIntosh Combined Cycle Facility | Georgia | 56150 | 11B | 24 | 24 |
| McManus | Georgia | 715 | 1 | 0 | 0 |
| McManus | Georgia | 715 | 2 | 1 | 1 |
| McManus | Georgia | 715 | 3A | 0 | 0 |
| McManus | Georgia | 715 | 3B | 0 | 0 |
| McManus | Georgia | 715 | 3C | 0 | 0 |
| McManus | Georgia | 715 | 4A | 0 | 0 |
| McManus | Georgia | 715 | 4B | 0 | 0 |
| McManus | Georgia | 715 | 4C | 0 | 0 |
| McManus | Georgia | 715 | 4D | 0 | 0 |
| McManus | Georgia | 715 | 4E | 0 | 0 |
| McManus | Georgia | 715 | 4F | 0 | 0 |
| Mid-Georgia Cogeneration | Georgia | 55040 | 1 | 21 | 21 |
| Mid-Georgia Cogeneration | Georgia | 55040 | 2 | 26 | 26 |
| Mitchell (GA) | Georgia | 727 | 3 | 10 | 10 |
| Mitchell (GA) | Georgia | 727 | 4AA | 0 | 0 |
| Mitchell (GA) | Georgia | 727 | 4AB | 0 | 0 |
| Mitchell (GA) | Georgia | 727 | 4BA | 0 | 0 |
| Mitchell (GA) | Georgia | 727 | 4BB | 0 | 0 |
| Mitchell (GA) | Georgia | 727 | 4CA | | |
| Mitchell (GA) | Georgia | 727 | 4CB | | |
| MPC Generating, LLC | Georgia | 7764 | 1 | 3 | 3 |
| MPC Generating, LLC | Georgia | 7764 | 2 | 5 | 5 |
| Murray Energy Facility | Georgia | 55382 | CCCT1 | 25 | 25 |
| Murray Energy Facility | Georgia | 55382 | CCCT2 | 25 | 25 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Murray Energy Facility | Georgia | 55382 | CCCT3 | 25 | 25 |
| Murray Energy Facility | Georgia | 55382 | CCCT4 | 25 | 25 |
| Robins | Georgia | 7348 | CT1 | 0 | 0 |
| Robins | Georgia | 7348 | CT2 | 0 | 0 |
| Scherer | Georgia | 6257 | 1 | 620 | 620 |
| Scherer | Georgia | 6257 | 2 | 617 | 617 |
| Scherer | Georgia | 6257 | 3 | 623 | 623 |
| Scherer | Georgia | 6257 | 4 | 657 | 657 |
| SEGCO Bainbridge | Georgia | 56015 | P1A | 0 | 0 |
| SEGCO Bainbridge | Georgia | 56015 | P1B | 0 | 0 |
| SEGCO Bainbridge | Georgia | 56015 | P2A | 0 | 0 |
| SEGCO Bainbridge | Georgia | 56015 | P2B | 0 | 0 |
| Sewell Creek Energy | Georgia | 7813 | 1 | 10 | 10 |
| Sewell Creek Energy | Georgia | 7813 | 2 | 10 | 10 |
| Sewell Creek Energy | Georgia | 7813 | 3 | 25 | 25 |
| Sewell Creek Energy | Georgia | 7813 | 4 | 22 | 22 |
| Smarr Energy Facility | Georgia | 7829 | 1 | 19 | 19 |
| Smarr Energy Facility | Georgia | 7829 | 2 | 8 | 8 |
| Sowega Power Project | Georgia | 7768 | CT2 | 12 | 12 |
| Sowega Power Project | Georgia | 7768 | CT3 | 12 | 12 |
| Talbot Energy Facility | Georgia | 7916 | 1 | 16 | 16 |
| Talbot Energy Facility | Georgia | 7916 | 2 | 14 | 14 |
| Talbot Energy Facility | Georgia | 7916 | 3 | 9 | 9 |
| Talbot Energy Facility | Georgia | 7916 | 4 | 12 | 12 |
| Talbot Energy Facility | Georgia | 7916 | 5 | 7 | 7 |
| Talbot Energy Facility | Georgia | 7916 | 6 | 9 | 9 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT1 | 6 | 6 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT2 | 8 | 8 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT3 | 6 | 6 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT4 | 9 | 9 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT5 | 7 | 7 |
| Tenaska Georgia Generating Station | Georgia | 55061 | CT6 | 8 | 8 |
| Walton County Power, LLC | Georgia | 55128 | T1 | 22 | 22 |
| Walton County Power, LLC | Georgia | 55128 | T2 | 22 | 22 |
| Walton County Power, LLC | Georgia | 55128 | T3 | 18 | 18 |
| Wansley (6052) | Georgia | 6052 | 1 | 438 | 438 |
| Wansley (6052) | Georgia | 6052 | 2 | 484 | 484 |
| Wansley (6052) | Georgia | 6052 | 5A | 0 | 0 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Wansley (7946) | Georgia | 7946 | CT9A | 23 | 23 |
| Wansley (7946) | Georgia | 7946 | CT9B | 26 | 26 |
| Wansley CC (55965) | Georgia | 55965 | 6A | 25 | 25 |
| Wansley CC (55965) | Georgia | 55965 | 6B | 27 | 27 |
| Wansley CC (55965) | Georgia | 55965 | 7A | 27 | 27 |
| Wansley CC (55965) | Georgia | 55965 | 7B | 28 | 28 |
| Washington County Power, LLC | Georgia | 55332 | T1 | 10 | 10 |
| Washington County Power, LLC | Georgia | 55332 | T2 | 9 | 9 |
| Washington County Power, LLC | Georgia | 55332 | T3 | 12 | 12 |
| Washington County Power, LLC | Georgia | 55332 | T4 | 9 | 9 |
| West Georgia Generating Facility | Georgia | 55267 | 1 | 23 | 23 |
| West Georgia Generating Facility | Georgia | 55267 | 2 | 10 | 10 |
| West Georgia Generating Facility | Georgia | 55267 | 3 | 22 | 22 |
| West Georgia Generating Facility | Georgia | 55267 | 4 | 12 | 12 |
| Yates | Georgia | 728 | Y1BR | 9 | 9 |
| Yates | Georgia | 728 | Y2BR | 35 | 35 |
| Yates | Georgia | 728 | Y3BR | 37 | 37 |
| Yates | Georgia | 728 | Y4BR | 34 | 34 |
| Yates | Georgia | 728 | Y5BR | 34 | 34 |
| Yates | Georgia | 728 | Y6BR | 127 | 127 |
| Yates | Georgia | 728 | Y7BR | 113 | 113 |
| Alsey Station | Illinois | 7818 | ACT1 | 1 | 1 |
| Alsey Station | Illinois | 7818 | ACT2 | 1 | 1 |
| Alsey Station | Illinois | 7818 | ACT5 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS01 | 3 | 3 |
| Aurora | Illinois | 55279 | AGS02 | 3 | 3 |
| Aurora | Illinois | 55279 | AGS03 | 4 | 4 |
| Aurora | Illinois | 55279 | AGS04 | 3 | 3 |
| Aurora | Illinois | 55279 | AGS05 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS06 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS07 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS08 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS09 | 1 | 1 |
| Aurora | Illinois | 55279 | AGS10 | 1 | 1 |
| Baldwin Energy Complex | Illinois | 889 | 1 | 497 | 497 |
| Baldwin Energy Complex | Illinois | 889 | 2 | 569 | 569 |
| Baldwin Energy Complex | Illinois | 889 | 3 | 597 | 597 |
| Calumet Energy Team, LLC | Illinois | 55296 | **1 | 10 | 10 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Calumet Energy Team, LLC | Illinois | 55296 | **2 | 10 | 10 |
| Coffeen | Illinois | 861 | 01 | 295 | 295 |
| Coffeen | Illinois | 861 | 02 | 458 | 458 |
| Cordova Energy Company | Illinois | 55188 | 1 | 3 | 3 |
| Cordova Energy Company | Illinois | 55188 | 2 | 3 | 3 |
| Crawford | Illinois | 867 | 7 | 137 | 137 |
| Crawford | Illinois | 867 | 8 | 175 | 175 |
| Crete Energy Park | Illinois | 55253 | GT1 | 1 | 1 |
| Crete Energy Park | Illinois | 55253 | GT2 | 1 | 1 |
| Crete Energy Park | Illinois | 55253 | GT3 | 1 | 1 |
| Crete Energy Park | Illinois | 55253 | GT4 | 1 | 1 |
| Dallman | Illinois | 963 | 4 | 169 | 169 |
| Dallman | Illinois | 963 | 31 | 46 | 46 |
| Dallman | Illinois | 963 | 32 | 51 | 51 |
| Dallman | Illinois | 963 | 33 | 142 | 142 |
| Duck Creek | Illinois | 6016 | 1 | 326 | 326 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT1 | 2 | 2 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT2 | 1 | 1 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT3 | 1 | 1 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT4 | 2 | 2 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT5 | 2 | 2 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT6 | 2 | 2 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT7 | 3 | 3 |
| Duke Energy Lee, II LLC | Illinois | 55236 | CT8 | 4 | 4 |
| E D Edwards | Illinois | 856 | 1 | 77 | 77 |
| E D Edwards | Illinois | 856 | 2 | 252 | 252 |
| E D Edwards | Illinois | 856 | 3 | 275 | 275 |
| Elgin Energy Center | Illinois | 55438 | CT01 | 7 | 7 |
| Elgin Energy Center | Illinois | 55438 | CT02 | 6 | 6 |
| Elgin Energy Center | Illinois | 55438 | CT03 | 8 | 8 |
| Elgin Energy Center | Illinois | 55438 | CT04 | 8 | 8 |
| Elwood Energy Facility | Illinois | 55199 | 1 | 11 | 11 |
| Elwood Energy Facility | Illinois | 55199 | 2 | 10 | 10 |
| Elwood Energy Facility | Illinois | 55199 | 3 | 10 | 10 |
| Elwood Energy Facility | Illinois | 55199 | 4 | 10 | 10 |
| Elwood Energy Facility | Illinois | 55199 | 5 | 16 | 16 |
| Elwood Energy Facility | Illinois | 55199 | 6 | 18 | 18 |
| Elwood Energy Facility | Illinois | 55199 | 7 | 14 | 14 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Elwood Energy Facility | Illinois | 55199 | 8 | 16 | 16 |
| Elwood Energy Facility | Illinois | 55199 | 9 | 6 | 6 |
| Factory Gas Turbine | Illinois | 8016 | 2 | 0 | 0 |
| Fisk | Illinois | 886 | 19 | 191 | 191 |
| Fisk | Illinois | 886 | 311 | 0 | 0 |
| Fisk | Illinois | 886 | 312 | 0 | 0 |
| Fisk | Illinois | 886 | 321 | 0 | 0 |
| Fisk | Illinois | 886 | 322 | 0 | 0 |
| Fisk | Illinois | 886 | 331 | 0 | 0 |
| Fisk | Illinois | 886 | 332 | 0 | 0 |
| Fisk | Illinois | 886 | 341 | | |
| Fisk | Illinois | 886 | 342 | 0 | 0 |
| Freedom Power Project | Illinois | 7842 | CT1 | 1 | 1 |
| Gibson City Power Plant | Illinois | 55201 | GCTG1 | 6 | 6 |
| Gibson City Power Plant | Illinois | 55201 | GCTG2 | 3 | 3 |
| Goose Creek Power Plant | Illinois | 55496 | CT-01 | 3 | 3 |
| Goose Creek Power Plant | Illinois | 55496 | CT-02 | 2 | 2 |
| Goose Creek Power Plant | Illinois | 55496 | CT-03 | 2 | 2 |
| Goose Creek Power Plant | Illinois | 55496 | CT-04 | 2 | 2 |
| Goose Creek Power Plant | Illinois | 55496 | CT-05 | 1 | 1 |
| Goose Creek Power Plant | Illinois | 55496 | CT-06 | 1 | 1 |
| Grand Tower | Illinois | 862 | CT01 | 44 | 44 |
| Grand Tower | Illinois | 862 | CT02 | 65 | 65 |
| Granite City Works | Illinois | 57072 | PB-1 | 49 | 49 |
| Havana | Illinois | 891 | 1 | | |
| Havana | Illinois | 891 | 2 | | |
| Havana | Illinois | 891 | 3 | | |
| Havana | Illinois | 891 | 4 | | |
| Havana | Illinois | 891 | 5 | | |
| Havana | Illinois | 891 | 6 | | |
| Havana | Illinois | 891 | 7 | | |
| Havana | Illinois | 891 | 8 | | |
| Havana | Illinois | 891 | 9 | 421 | 421 |
| Hennepin Power Station | Illinois | 892 | 1 | 68 | 68 |
| Hennepin Power Station | Illinois | 892 | 2 | 202 | 202 |
| Holland Energy Facility | Illinois | 55334 | CTG1 | 20 | 20 |
| Holland Energy Facility | Illinois | 55334 | CTG2 | 20 | 20 |
| Hutsonville | Illinois | 863 | 05 | 55 | 55 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Hutsonville | Illinois | 863 | 06 | 56 | 56 |
| Interstate | Illinois | 7425 | 1 | 5 | 5 |
| Joliet 29 | Illinois | 384 | 71 | 209 | 209 |
| Joliet 29 | Illinois | 384 | 72 | 211 | 211 |
| Joliet 29 | Illinois | 384 | 81 | 220 | 220 |
| Joliet 29 | Illinois | 384 | 82 | 231 | 231 |
| Joliet 9 | Illinois | 874 | 5 | 209 | 209 |
| Joppa Steam | Illinois | 887 | 1 | 155 | 155 |
| Joppa Steam | Illinois | 887 | 2 | 158 | 158 |
| Joppa Steam | Illinois | 887 | 3 | 148 | 148 |
| Joppa Steam | Illinois | 887 | 4 | 162 | 162 |
| Joppa Steam | Illinois | 887 | 5 | 159 | 159 |
| Joppa Steam | Illinois | 887 | 6 | 165 | 165 |
| Kendall Energy Facility | Illinois | 55131 | GTG-1 | 31 | 31 |
| Kendall Energy Facility | Illinois | 55131 | GTG-2 | 34 | 34 |
| Kendall Energy Facility | Illinois | 55131 | GTG-3 | 33 | 33 |
| Kendall Energy Facility | Illinois | 55131 | GTG-4 | 32 | 32 |
| Kincaid Station | Illinois | 876 | 1 | 373 | 373 |
| Kincaid Station | Illinois | 876 | 2 | 426 | 426 |
| Kinmundy Power Plant | Illinois | 55204 | KCTG1 | 2 | 2 |
| Kinmundy Power Plant | Illinois | 55204 | KCTG2 | 3 | 3 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-1 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-2 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-3 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-4 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-5 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-6 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-7 | 2 | 2 |
| Lincoln Generating Facility | Illinois | 55222 | CTG-8 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT01 | 1 | 1 |
| LSP University Park, LLC | Illinois | 55640 | CT02 | 1 | 1 |
| LSP University Park, LLC | Illinois | 55640 | CT03 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT04 | 1 | 1 |
| LSP University Park, LLC | Illinois | 55640 | CT05 | 1 | 1 |
| LSP University Park, LLC | Illinois | 55640 | CT06 | 1 | 1 |
| LSP University Park, LLC | Illinois | 55640 | CT07 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT08 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT09 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| LSP University Park, LLC | Illinois | 55640 | CT10 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT11 | 2 | 2 |
| LSP University Park, LLC | Illinois | 55640 | CT12 | 1 | 1 |
| Marion | Illinois | 976 | 4 | 198 | 198 |
| Marion | Illinois | 976 | 5 | 1 | 1 |
| Marion | Illinois | 976 | 6 | 1 | 1 |
| Marion | Illinois | 976 | 123 | 132 | 132 |
| MEPI Gt Facility | Illinois | 7858 | 1 | 2 | 2 |
| MEPI Gt Facility | Illinois | 7858 | 2 | 2 | 2 |
| MEPI Gt Facility | Illinois | 7858 | 3 | 0 | 0 |
| MEPI Gt Facility | Illinois | 7858 | 4 | 1 | 1 |
| MEPI Gt Facility | Illinois | 7858 | 5 | 1 | 1 |
| Meredosia | Illinois | 864 | 01 | | |
| Meredosia | Illinois | 864 | 02 | | |
| Meredosia | Illinois | 864 | 03 | | |
| Meredosia | Illinois | 864 | 04 | | |
| Meredosia | Illinois | 864 | 05 | 126 | 126 |
| Meredosia | Illinois | 864 | 06 | 0 | 0 |
| Morris Cogeneration, LLC | Illinois | 55216 | CTG1 | 22 | 22 |
| Morris Cogeneration, LLC | Illinois | 55216 | CTG2 | 25 | 25 |
| Morris Cogeneration, LLC | Illinois | 55216 | CTG3 | 31 | 31 |
| Newton | Illinois | 6017 | 1 | 474 | 474 |
| Newton | Illinois | 6017 | 2 | 465 | 465 |
| NRG Rockford Energy Center | Illinois | 55238 | 0001 | 6 | 6 |
| NRG Rockford Energy Center | Illinois | 55238 | 0002 | 5 | 5 |
| NRG Rockford II Energy Center | Illinois | 55936 | U1 | 7 | 7 |
| Pinckneyville Power Plant | Illinois | 55202 | CT01 | 6 | 6 |
| Pinckneyville Power Plant | Illinois | 55202 | CT02 | 7 | 7 |
| Pinckneyville Power Plant | Illinois | 55202 | CT03 | 6 | 6 |
| Pinckneyville Power Plant | Illinois | 55202 | CT04 | 6 | 6 |
| Pinckneyville Power Plant | Illinois | 55202 | CT05 | 1 | 1 |
| Pinckneyville Power Plant | Illinois | 55202 | CT06 | 1 | 1 |
| Pinckneyville Power Plant | Illinois | 55202 | CT07 | 0 | 0 |
| Pinckneyville Power Plant | Illinois | 55202 | CT08 | 0 | 0 |
| Powerton | Illinois | 879 | 51 | 309 | 309 |
| Powerton | Illinois | 879 | 52 | 327 | 327 |
| Powerton | Illinois | 879 | 61 | 350 | 350 |
| Powerton | Illinois | 879 | 62 | 332 | 332 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Prairie State Generating Station | Illinois | 55856 | 01 | 687 | 687 |
| Prairie State Generating Station | Illinois | 55856 | 02 | 640 | 640 |
| Raccoon Creek Power Plant | Illinois | 55417 | CT-01 | 2 | 2 |
| Raccoon Creek Power Plant | Illinois | 55417 | CT-02 | 1 | 1 |
| Raccoon Creek Power Plant | Illinois | 55417 | CT-03 | 1 | 1 |
| Raccoon Creek Power Plant | Illinois | 55417 | CT-04 | 2 | 2 |
| Rocky Road Power, LLC | Illinois | 55109 | T1 | 8 | 8 |
| Rocky Road Power, LLC | Illinois | 55109 | T2 | 7 | 7 |
| Rocky Road Power, LLC | Illinois | 55109 | T3 | 2 | 2 |
| Rocky Road Power, LLC | Illinois | 55109 | T4 | 9 | 9 |
| Shelby County | Illinois | 55237 | SCE1 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE2 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE3 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE4 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE5 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE6 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE7 | 1 | 1 |
| Shelby County | Illinois | 55237 | SCE8 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG10 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG11 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG12 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG5 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG6 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG7 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG8 | 1 | 1 |
| Southeast Chicago Energy Project | Illinois | 55281 | CTG9 | 1 | 1 |
| Tilton Power Station | Illinois | 7760 | 1 | 5 | 5 |
| Tilton Power Station | Illinois | 7760 | 2 | 5 | 5 |
| Tilton Power Station | Illinois | 7760 | 3 | 5 | 5 |
| Tilton Power Station | Illinois | 7760 | 4 | 6 | 6 |
| University Park Energy | Illinois | 55250 | UP1 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP10 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP11 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP12 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP2 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP3 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP4 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP5 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| University Park Energy | Illinois | 55250 | UP6 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP7 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP8 | 2 | 2 |
| University Park Energy | Illinois | 55250 | UP9 | 2 | 2 |
| Venice | Illinois | 913 | CT03 | 13 | 13 |
| Venice | Illinois | 913 | CT04 | 14 | 14 |
| Venice | Illinois | 913 | CT05 | 5 | 5 |
| Venice | Illinois | 913 | CT1 | | |
| Venice | Illinois | 913 | CT2A | 2 | 2 |
| Venice | Illinois | 913 | CT2B | 2 | 2 |
| Vermilion Power Station | Illinois | 897 | 1 | | |
| Vermilion Power Station | Illinois | 897 | 2 | | |
| Waukegan | Illinois | 883 | 7 | 215 | 215 |
| Waukegan | Illinois | 883 | 8 | 292 | 292 |
| Waukegan | Illinois | 883 | 311 | 0 | 0 |
| Waukegan | Illinois | 883 | 312 | 0 | 0 |
| Waukegan | Illinois | 883 | 321 | 0 | 0 |
| Waukegan | Illinois | 883 | 322 | 0 | 0 |
| Will County | Illinois | 884 | 1 | | |
| Will County | Illinois | 884 | 2 | | |
| Will County | Illinois | 884 | 3 | 204 | 204 |
| Will County | Illinois | 884 | 4 | 345 | 345 |
| Wood River Power Station | Illinois | 898 | 1 | | |
| Wood River Power Station | Illinois | 898 | 2 | | |
| Wood River Power Station | Illinois | 898 | 3 | | |
| Wood River Power Station | Illinois | 898 | 4 | 90 | 90 |
| Wood River Power Station | Illinois | 898 | 5 | 332 | 332 |
| Zion Energy Center | Illinois | 55392 | CT-1 | 12 | 12 |
| Zion Energy Center | Illinois | 55392 | CT-2 | 11 | 11 |
| Zion Energy Center | Illinois | 55392 | CT-3 | 11 | 11 |
| A B Brown Generating Station | Indiana | 6137 | 1 | 324 | 324 |
| A B Brown Generating Station | Indiana | 6137 | 2 | 326 | 326 |
| A B Brown Generating Station | Indiana | 6137 | 3 | 6 | 6 |
| A B Brown Generating Station | Indiana | 6137 | 4 | 2 | 2 |
| Alcoa Allowance Management Inc | Indiana | 6705 | 4 | 453 | 453 |
| Anderson | Indiana | 7336 | ACT1 | 2 | 2 |
| Anderson | Indiana | 7336 | ACT2 | 2 | 2 |
| Anderson | Indiana | 7336 | ACT3 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bailly Generating Station | Indiana | 995 | 7 | 223 | 223 |
| Bailly Generating Station | Indiana | 995 | 8 | 424 | 424 |
| Bailly Generating Station | Indiana | 995 | 10 | 1 | 1 |
| Broadway Avenue Generating Station | Indiana | 1011 | 1 | 1 | 1 |
| Broadway Avenue Generating Station | Indiana | 1011 | 2 | 5 | 5 |
| Cayuga | Indiana | 1001 | 1 | 640 | 640 |
| Cayuga | Indiana | 1001 | 2 | 574 | 574 |
| Cayuga | Indiana | 1001 | 4 | 7 | 7 |
| Clifty Creek | Indiana | 983 | 1 | 234 | 234 |
| Clifty Creek | Indiana | 983 | 2 | 239 | 239 |
| Clifty Creek | Indiana | 983 | 3 | 233 | 233 |
| Clifty Creek | Indiana | 983 | 4 | 224 | 224 |
| Clifty Creek | Indiana | 983 | 5 | 231 | 231 |
| Clifty Creek | Indiana | 983 | 6 | 220 | 220 |
| Connersville Peaking Station | Indiana | 1002 | 1A | 0 | 0 |
| Connersville Peaking Station | Indiana | 1002 | 1B | 0 | 0 |
| Connersville Peaking Station | Indiana | 1002 | 2A | 0 | 0 |
| Connersville Peaking Station | Indiana | 1002 | 2B | 0 | 0 |
| Dean H Mitchell Generating Station | Indiana | 996 | 4 | | |
| Dean H Mitchell Generating Station | Indiana | 996 | 5 | | |
| Dean H Mitchell Generating Station | Indiana | 996 | 6 | | |
| Dean H Mitchell Generating Station | Indiana | 996 | 11 | | |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 1 | 3 | 3 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 2 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 3 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 4 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 5 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 6 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 7 | 2 | 2 |
| Duke Energy Vermillion, II LLC | Indiana | 55111 | 8 | 2 | 2 |
| Edwardsport | Indiana | 1004 | 6-1 | | |
| Edwardsport | Indiana | 1004 | 7-1 | | |
| Edwardsport | Indiana | 1004 | 7-2 | | |
| Edwardsport | Indiana | 1004 | 8-1 | | |
| Edwardsport Generating Station | Indiana | 1004 | CTG1 | 159 | 159 |
| Edwardsport Generating Station | Indiana | 1004 | CTG2 | 184 | 184 |
| F B Culley Generating Station | Indiana | 1012 | 2 | 70 | 70 |
| F B Culley Generating Station | Indiana | 1012 | 3 | 395 | 395 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Frank E Ratts | Indiana | 1043 | 1SG1 | 65 | 65 |
| Frank E Ratts | Indiana | 1043 | 2SG1 | 76 | 76 |
| Georgetown Substation | Indiana | 7759 | GT1 | 2 | 2 |
| Georgetown Substation | Indiana | 7759 | GT2 | 5 | 5 |
| Georgetown Substation | Indiana | 7759 | GT3 | 4 | 4 |
| Georgetown Substation | Indiana | 7759 | GT4 | 4 | 4 |
| Gibson | Indiana | 6113 | 1 | 788 | 788 |
| Gibson | Indiana | 6113 | 2 | 789 | 789 |
| Gibson | Indiana | 6113 | 3 | 768 | 768 |
| Gibson | Indiana | 6113 | 4 | 665 | 665 |
| Gibson | Indiana | 6113 | 5 | 684 | 684 |
| Harding Street Station (EW Stout) | Indiana | 990 | 9 | 0 | 0 |
| Harding Street Station (EW Stout) | Indiana | 990 | 10 | 0 | 0 |
| Harding Street Station (EW Stout) | Indiana | 990 | 50 | 129 | 129 |
| Harding Street Station (EW Stout) | Indiana | 990 | 60 | 129 | 129 |
| Harding Street Station (EW Stout) | Indiana | 990 | 70 | 574 | 574 |
| Harding Street Station (EW Stout) | Indiana | 990 | GT4 | 10 | 10 |
| Harding Street Station (EW Stout) | Indiana | 990 | GT5 | 11 | 11 |
| Harding Street Station (EW Stout) | Indiana | 990 | GT6 | 17 | 17 |
| Henry County Generating Station | Indiana | 7763 | 1 | 11 | 11 |
| Henry County Generating Station | Indiana | 7763 | 2 | 11 | 11 |
| Henry County Generating Station | Indiana | 7763 | 3 | 11 | 11 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 1 | 4 | 4 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 2 | 4 | 4 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 3 | 4 | 4 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 4 | 4 | 4 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 5 | 4 | 4 |
| Hoosier Energy Lawrence Co Station | Indiana | 7948 | 6 | 3 | 3 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 1 | 1 | 1 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 2 | 1 | 1 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 3 | 10 | 10 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 4 | 30 | 30 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 5 | 35 | 35 |
| IPL Eagle Valley Generating Station | Indiana | 991 | 6 | 75 | 75 |
| Lawrenceburg Energy Facility | Indiana | 55502 | 1 | 39 | 39 |
| Lawrenceburg Energy Facility | Indiana | 55502 | 2 | 38 | 38 |
| Lawrenceburg Energy Facility | Indiana | 55502 | 3 | 26 | 26 |
| Lawrenceburg Energy Facility | Indiana | 55502 | 4 | 33 | 33 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Merom | Indiana | 6213 | 1SG1 | 708 | 708 |
| Merom | Indiana | 6213 | 2SG1 | 676 | 676 |
| Michigan City Generating Station | Indiana | 997 | 4 | | |
| Michigan City Generating Station | Indiana | 997 | 5 | | |
| Michigan City Generating Station | Indiana | 997 | 6 | | |
| Michigan City Generating Station | Indiana | 997 | 12 | 547 | 547 |
| Montpelier Electric Gen Station | Indiana | 55229 | G1CT1 | 5 | 5 |
| Montpelier Electric Gen Station | Indiana | 55229 | G1CT2 | 5 | 5 |
| Montpelier Electric Gen Station | Indiana | 55229 | G2CT1 | 4 | 4 |
| Montpelier Electric Gen Station | Indiana | 55229 | G2CT2 | 5 | 5 |
| Montpelier Electric Gen Station | Indiana | 55229 | G3CT1 | 4 | 4 |
| Montpelier Electric Gen Station | Indiana | 55229 | G3CT2 | 5 | 5 |
| Montpelier Electric Gen Station | Indiana | 55229 | G4CT1 | 5 | 5 |
| Montpelier Electric Gen Station | Indiana | 55229 | G4CT2 | 4 | 4 |
| Noblesville | Indiana | 1007 | CT3 | 8 | 8 |
| Noblesville | Indiana | 1007 | CT4 | 8 | 8 |
| Noblesville | Indiana | 1007 | CT5 | 9 | 9 |
| Petersburg | Indiana | 994 | 1 | 368 | 368 |
| Petersburg | Indiana | 994 | 2 | 569 | 569 |
| Petersburg | Indiana | 994 | 3 | 672 | 672 |
| Petersburg | Indiana | 994 | 4 | 750 | 750 |
| Portside Energy | Indiana | 55096 | CT | 26 | 26 |
| R Gallagher | Indiana | 1008 | 1 | 42 | 42 |
| R Gallagher | Indiana | 1008 | 2 | 68 | 68 |
| R Gallagher | Indiana | 1008 | 3 | 51 | 51 |
| R Gallagher | Indiana | 1008 | 4 | 59 | 59 |
| R M Schahfer Generating Station | Indiana | 6085 | 14 | 507 | 507 |
| R M Schahfer Generating Station | Indiana | 6085 | 15 | 633 | 633 |
| R M Schahfer Generating Station | Indiana | 6085 | 17 | 451 | 451 |
| R M Schahfer Generating Station | Indiana | 6085 | 18 | 472 | 472 |
| R M Schahfer Generating Station | Indiana | 6085 | 16A | 10 | 10 |
| R M Schahfer Generating Station | Indiana | 6085 | 16B | 7 | 7 |
| Richmond (IN) | Indiana | 7335 | RCT1 | 1 | 1 |
| Richmond (IN) | Indiana | 7335 | RCT2 | 2 | 2 |
| Rockport | Indiana | 6166 | MB1 | 1,823 | 1,823 |
| Rockport | Indiana | 6166 | MB2 | 1,858 | 1,858 |
| State Line Generating Station (IN) | Indiana | 981 | 3 | 289 | 289 |
| State Line Generating Station (IN) | Indiana | 981 | 4 | 331 | 331 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Sugar Creek Generating Station | Indiana | 55364 | CT11 | 23 | 23 |
| Sugar Creek Generating Station | Indiana | 55364 | CT12 | 23 | 23 |
| Tanners Creek | Indiana | 988 | U1 | 43 | 43 |
| Tanners Creek | Indiana | 988 | U2 | 69 | 69 |
| Tanners Creek | Indiana | 988 | U3 | 141 | 141 |
| Tanners Creek | Indiana | 988 | U4 | 403 | 403 |
| Wabash River Gen Station | Indiana | 1010 | 1 | 198 | 198 |
| Wabash River Gen Station | Indiana | 1010 | 2 | 59 | 59 |
| Wabash River Gen Station | Indiana | 1010 | 3 | 68 | 68 |
| Wabash River Gen Station | Indiana | 1010 | 4 | 73 | 73 |
| Wabash River Gen Station | Indiana | 1010 | 5 | 34 | 34 |
| Wabash River Gen Station | Indiana | 1010 | 6 | 324 | 324 |
| Wheatland Generating Facility LLC | Indiana | 55224 | EU-01 | 13 | 13 |
| Wheatland Generating Facility LLC | Indiana | 55224 | EU-02 | 9 | 9 |
| Wheatland Generating Facility LLC | Indiana | 55224 | EU-03 | 10 | 10 |
| Wheatland Generating Facility LLC | Indiana | 55224 | EU-04 | 11 | 11 |
| Whitewater Valley | Indiana | 1040 | 1 | 12 | 12 |
| Whitewater Valley | Indiana | 1040 | 2 | 19 | 19 |
| Whiting Clean Energy, Inc. | Indiana | 55259 | CT1 | 26 | 26 |
| Whiting Clean Energy, Inc. | Indiana | 55259 | CT2 | 24 | 24 |
| Worthington Generation | Indiana | 55148 | 1 | 3 | 3 |
| Worthington Generation | Indiana | 55148 | 2 | 2 | 2 |
| Worthington Generation | Indiana | 55148 | 3 | 2 | 2 |
| Worthington Generation | Indiana | 55148 | 4 | 2 | 2 |
| Ames | Iowa | 1122 | 7 | 51 | 51 |
| Ames | Iowa | 1122 | 8 | 97 | 97 |
| Burlington (IA) | Iowa | 1104 | 1 | 456 | 456 |
| Centerville | Iowa | 1105 | 1 | 1 | 1 |
| Centerville | Iowa | 1105 | 2 | 1 | 1 |
| Dayton Avenue Substation | Iowa | 6463 | GT2 | 1 | 1 |
| Dubuque | Iowa | 1046 | 1 | 28 | 28 |
| Dubuque | Iowa | 1046 | 5 | 20 | 20 |
| Dubuque | Iowa | 1046 | 6 | 5 | 5 |
| Earl F Wisdom | Iowa | 1217 | 1 | 17 | 17 |
| Earl F Wisdom | Iowa | 1217 | 2 | 2 | 2 |
| Electrifarm | Iowa | 6063 | 1 | 8 | 8 |
| Electrifarm | Iowa | 6063 | 2 | 10 | 10 |
| Electrifarm | Iowa | 6063 | 3 | 12 | 12 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Emery Station | Iowa | 8031 | 11 | 15 | 15 |
| Emery Station | Iowa | 8031 | 12 | 17 | 17 |
| Exira Station | Iowa | 56013 | U-1 | 6 | 6 |
| Exira Station | Iowa | 56013 | U-2 | 5 | 5 |
| Exira Station | Iowa | 56013 | U-3 | 6 | 6 |
| Fair Station | Iowa | 1218 | 2 | 58 | 58 |
| George Neal North | Iowa | 1091 | 1 | 228 | 228 |
| George Neal North | Iowa | 1091 | 2 | 449 | 449 |
| George Neal North | Iowa | 1091 | 3 | 829 | 829 |
| George Neal South | Iowa | 7343 | 4 | 1,310 | 1,310 |
| Greater Des Moines Energy Center | Iowa | 7985 | 1 | 6 | 6 |
| Greater Des Moines Energy Center | Iowa | 7985 | 2 | 6 | 6 |
| Grinnell | Iowa | 7137 | 1 | 3 | 3 |
| Grinnell | Iowa | 7137 | 2 | 2 | 2 |
| Lansing | Iowa | 1047 | 1 | | |
| Lansing | Iowa | 1047 | 2 | | |
| Lansing | Iowa | 1047 | 3 | | |
| Lansing | Iowa | 1047 | 4 | 419 | 419 |
| Lime Creek | Iowa | 7155 | **1 | 0 | 0 |
| Lime Creek | Iowa | 7155 | **2 | 0 | 0 |
| Louisa | Iowa | 6664 | 101 | 1,523 | 1,523 |
| Marshalltown CTs | Iowa | 1068 | 1A | 2 | 2 |
| Marshalltown CTs | Iowa | 1068 | 1B | 2 | 2 |
| Marshalltown CTs | Iowa | 1068 | 2A | 2 | 2 |
| Marshalltown CTs | Iowa | 1068 | 2B | 3 | 3 |
| Marshalltown CTs | Iowa | 1068 | 3A | 1 | 1 |
| Marshalltown CTs | Iowa | 1068 | 3B | 1 | 1 |
| Milton L Kapp | Iowa | 1048 | 2 | 316 | 316 |
| Muscatine | Iowa | 1167 | 8 | 162 | 162 |
| Muscatine | Iowa | 1167 | 9 | 276 | 276 |
| Ottumwa | Iowa | 6254 | 1 | 1,361 | 1,361 |
| Pella | Iowa | 1175 | 6 | 11 | 11 |
| Pella | Iowa | 1175 | 7 | 17 | 17 |
| Pella | Iowa | 1175 | 8 | 2 | 2 |
| Pleasant Hill Energy Center | Iowa | 7145 | 1 | 4 | 4 |
| Pleasant Hill Energy Center | Iowa | 7145 | 2 | 5 | 5 |
| Pleasant Hill Energy Center | Iowa | 7145 | 3 | 10 | 10 |
| Prairie Creek | Iowa | 1073 | 3 | 76 | 76 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Prairie Creek | Iowa | 1073 | 4 | 207 | 207 |
| Riverside (1081) | Iowa | 1081 | 9 | 214 | 214 |
| Sixth Street | Iowa | 1058 | 2 | | |
| Sixth Street | Iowa | 1058 | 3 | | |
| Sixth Street | Iowa | 1058 | 4 | | |
| Sixth Street | Iowa | 1058 | 5 | | |
| Streeter Station | Iowa | 1131 | 7 | 11 | 11 |
| Summit Lake | Iowa | 1206 | 1G | 7 | 7 |
| Summit Lake | Iowa | 1206 | 2G | 8 | 8 |
| Sutherland | Iowa | 1077 | 1 | 16 | 16 |
| Sutherland | Iowa | 1077 | 2 | | |
| Sutherland | Iowa | 1077 | 3 | 87 | 87 |
| Sycamore Combustion Turbine | Iowa | 8029 | 1 | 8 | 8 |
| Sycamore Combustion Turbine | Iowa | 8029 | 2 | 8 | 8 |
| Walter Scott Jr. Energy Center | Iowa | 1082 | 1 | 101 | 101 |
| Walter Scott Jr. Energy Center | Iowa | 1082 | 2 | 163 | 163 |
| Walter Scott Jr. Energy Center | Iowa | 1082 | 3 | 1,517 | 1,517 |
| Walter Scott Jr. Energy Center | Iowa | 1082 | 4 | 748 | 748 |
| Abilene Energy Center Combustion Turbine | Kansas | 1251 | GT1 | 2 | 2 |
| Chanute 2 | Kansas | 1268 | 14 | 5 | 5 |
| Cimarron River | Kansas | 1230 | 1 | 45 | 45 |
| Clifton Station | Kansas | 8037 | CL1 | 3 | 3 |
| Coffeyville | Kansas | 1271 | 4 | 11 | 11 |
| East 12th Street | Kansas | 7013 | 4 | 7 | 7 |
| Emporia Energy Center | Kansas | 56502 | EEC1 | 18 | 18 |
| Emporia Energy Center | Kansas | 56502 | EEC2 | 19 | 19 |
| Emporia Energy Center | Kansas | 56502 | EEC3 | 18 | 18 |
| Emporia Energy Center | Kansas | 56502 | EEC4 | 20 | 20 |
| Emporia Energy Center | Kansas | 56502 | EEC5 | 15 | 15 |
| Emporia Energy Center | Kansas | 56502 | EEC6 | 15 | 15 |
| Emporia Energy Center | Kansas | 56502 | EEC7 | 11 | 11 |
| Fort Dodge aka Judson Large | Kansas | 1233 | 4 | 92 | 92 |
| Garden City | Kansas | 1336 | S-2 | 31 | 31 |
| Garden City | Kansas | 1336 | S-4 | 6 | 6 |
| Garden City | Kansas | 1336 | S-5 | 6 | 6 |
| Gordon Evans Energy Center | Kansas | 1240 | 1 | 54 | 54 |
| Gordon Evans Energy Center | Kansas | 1240 | 2 | 125 | 125 |
| Gordon Evans Energy Center | Kansas | 1240 | E1CT | 3 | 3 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Gordon Evans Energy Center | Kansas | 1240 | E2CT | 4 | 4 |
| Gordon Evans Energy Center | Kansas | 1240 | E3CT | 20 | 20 |
| Great Bend Station aka Arthur Mullergren | Kansas | 1235 | 3 | 43 | 43 |
| Holcomb | Kansas | 108 | SGU1 | 468 | 468 |
| Hutchinson Energy Center | Kansas | 1248 | 4 | 26 | 26 |
| Hutchinson Energy Center | Kansas | 1248 | CT-1 | 2 | 2 |
| Hutchinson Energy Center | Kansas | 1248 | CT-2 | 2 | 2 |
| Hutchinson Energy Center | Kansas | 1248 | CT-3 | 2 | 2 |
| Hutchinson Energy Center | Kansas | 1248 | CT-4 | 0 | 0 |
| Jeffrey Energy Center | Kansas | 6068 | 1 | 1,037 | 1,037 |
| Jeffrey Energy Center | Kansas | 6068 | 2 | 997 | 997 |
| Jeffrey Energy Center | Kansas | 6068 | 3 | 1,031 | 1,031 |
| La Cygne | Kansas | 1241 | 1 | 1,018 | 1,018 |
| La Cygne | Kansas | 1241 | 2 | 911 | 911 |
| Lawrence Energy Center | Kansas | 1250 | 3 | 78 | 78 |
| Lawrence Energy Center | Kansas | 1250 | 4 | 153 | 153 |
| Lawrence Energy Center | Kansas | 1250 | 5 | 499 | 499 |
| McPherson 2 | Kansas | 1305 | GT1 | 4 | 4 |
| McPherson 2 | Kansas | 1305 | GT2 | 0 | 0 |
| McPherson 2 | Kansas | 1305 | GT3 | 4 | 4 |
| McPherson 3 | Kansas | 7515 | 1 | 3 | 3 |
| Murray Gill Energy Center | Kansas | 1242 | 1 | 9 | 9 |
| Murray Gill Energy Center | Kansas | 1242 | 2 | 11 | 11 |
| Murray Gill Energy Center | Kansas | 1242 | 3 | 41 | 41 |
| Murray Gill Energy Center | Kansas | 1242 | 4 | 40 | 40 |
| Nearman Creek | Kansas | 6064 | CT4 | 16 | 16 |
| Nearman Creek | Kansas | 6064 | N1 | 340 | 340 |
| Neosho Energy Center | Kansas | 1243 | 7 | 2 | 2 |
| Osawatomie Generating Station | Kansas | 7928 | 1 | 2 | 2 |
| Quindaro | Kansas | 1295 | 1 | 112 | 112 |
| Quindaro | Kansas | 1295 | 2 | 125 | 125 |
| Quindaro | Kansas | 1295 | CT2 | 1 | 1 |
| Quindaro | Kansas | 1295 | CT3 | 0 | 0 |
| Riverton | Kansas | 1239 | 12 | 30 | 30 |
| Riverton | Kansas | 1239 | 39 | 13 | 13 |
| Riverton | Kansas | 1239 | 40 | 34 | 34 |
| Tecumseh Energy Center | Kansas | 1252 | 9 | 101 | 101 |
| Tecumseh Energy Center | Kansas | 1252 | 10 | 174 | 174 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| West Gardner Generating Station | Kansas | 7929 | 1 | 3 | 3 |
| West Gardner Generating Station | Kansas | 7929 | 2 | 3 | 3 |
| West Gardner Generating Station | Kansas | 7929 | 3 | 3 | 3 |
| West Gardner Generating Station | Kansas | 7929 | 4 | 3 | 3 |
| Big Sandy | Kentucky | 1353 | BSU1 | 287 | 287 |
| Big Sandy | Kentucky | 1353 | BSU2 | 758 | 758 |
| Bluegrass Generation Company, LLC | Kentucky | 55164 | GTG1 | 6 | 6 |
| Bluegrass Generation Company, LLC | Kentucky | 55164 | GTG2 | 6 | 6 |
| Bluegrass Generation Company, LLC | Kentucky | 55164 | GTG3 | 13 | 13 |
| Cane Run | Kentucky | 1363 | 4 | 189 | 189 |
| Cane Run | Kentucky | 1363 | 5 | 219 | 219 |
| Cane Run | Kentucky | 1363 | 6 | 264 | 264 |
| Coleman | Kentucky | 1381 | C1 | 240 | 240 |
| Coleman | Kentucky | 1381 | C2 | 247 | 247 |
| Coleman | Kentucky | 1381 | C3 | 271 | 271 |
| D B Wilson | Kentucky | 6823 | W1 | 534 | 534 |
| E W Brown | Kentucky | 1355 | 1 | 109 | 109 |
| E W Brown | Kentucky | 1355 | 2 | 209 | 209 |
| E W Brown | Kentucky | 1355 | 3 | 460 | 460 |
| E W Brown | Kentucky | 1355 | 5 | 16 | 16 |
| E W Brown | Kentucky | 1355 | 6 | 22 | 22 |
| E W Brown | Kentucky | 1355 | 7 | 24 | 24 |
| E W Brown | Kentucky | 1355 | 8 | 5 | 5 |
| E W Brown | Kentucky | 1355 | 9 | 12 | 12 |
| E W Brown | Kentucky | 1355 | 10 | 8 | 8 |
| E W Brown | Kentucky | 1355 | 11 | 9 | 9 |
| East Bend | Kentucky | 6018 | 2 | 893 | 893 |
| Elmer Smith | Kentucky | 1374 | 1 | 228 | 228 |
| Elmer Smith | Kentucky | 1374 | 2 | 366 | 366 |
| Ghent | Kentucky | 1356 | 1 | 658 | 658 |
| Ghent | Kentucky | 1356 | 2 | 716 | 716 |
| Ghent | Kentucky | 1356 | 3 | 767 | 767 |
| Ghent | Kentucky | 1356 | 4 | 665 | 665 |
| Green River | Kentucky | 1357 | 4 | 97 | 97 |
| Green River | Kentucky | 1357 | 5 | 138 | 138 |
| H L Spurlock | Kentucky | 6041 | 1 | 369 | 369 |
| H L Spurlock | Kentucky | 6041 | 2 | 712 | 712 |
| H L Spurlock | Kentucky | 6041 | 3 | 327 | 327 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| H L Spurlock | Kentucky | 6041 | 4 | 267 | 267 |
| HMP&L Station 2 | Kentucky | 1382 | H1 | 243 | 243 |
| HMP&L Station 2 | Kentucky | 1382 | H2 | 214 | 214 |
| John S. Cooper | Kentucky | 1384 | 1 | 98 | 98 |
| John S. Cooper | Kentucky | 1384 | 2 | 164 | 164 |
| Marshall | Kentucky | 55232 | CT1 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT2 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT3 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT4 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT5 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT6 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT7 | 2 | 2 |
| Marshall | Kentucky | 55232 | CT8 | 2 | 2 |
| Mill Creek | Kentucky | 1364 | 1 | 405 | 405 |
| Mill Creek | Kentucky | 1364 | 2 | 445 | 445 |
| Mill Creek | Kentucky | 1364 | 3 | 562 | 562 |
| Mill Creek | Kentucky | 1364 | 4 | 641 | 641 |
| Paddy's Run | Kentucky | 1366 | 12 | 1 | 1 |
| Paddy's Run | Kentucky | 1366 | 13 | 23 | 23 |
| Paducah Power Systems Plant 1 | Kentucky | 56556 | EU01A | 2 | 2 |
| Paducah Power Systems Plant 1 | Kentucky | 56556 | EU01B | 2 | 2 |
| Paducah Power Systems Plant 1 | Kentucky | 56556 | EU02A | 1 | 1 |
| Paducah Power Systems Plant 1 | Kentucky | 56556 | EU02B | 2 | 2 |
| Paradise | Kentucky | 1378 | 1 | 1,037 | 1,037 |
| Paradise | Kentucky | 1378 | 2 | 1,086 | 1,086 |
| Paradise | Kentucky | 1378 | 3 | 1,303 | 1,303 |
| R D Green | Kentucky | 6639 | G1 | 405 | 405 |
| R D Green | Kentucky | 6639 | G2 | 426 | 426 |
| Riverside Generating Company | Kentucky | 55198 | GTG101 | 29 | 29 |
| Riverside Generating Company | Kentucky | 55198 | GTG201 | 30 | 30 |
| Riverside Generating Company | Kentucky | 55198 | GTG301 | 27 | 27 |
| Riverside Generating Company | Kentucky | 55198 | GTG401 | 31 | 31 |
| Riverside Generating Company | Kentucky | 55198 | GTG501 | 19 | 19 |
| Robert Reid | Kentucky | 1383 | R1 | 39 | 39 |
| Robert Reid | Kentucky | 1383 | RT | 3 | 3 |
| Shawnee | Kentucky | 1379 | 1 | 196 | 196 |
| Shawnee | Kentucky | 1379 | 2 | 195 | 195 |
| Shawnee | Kentucky | 1379 | 3 | 187 | 187 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Shawnee | Kentucky | 1379 | 4 | 198 | 198 |
| Shawnee | Kentucky | 1379 | 5 | 188 | 188 |
| Shawnee | Kentucky | 1379 | 6 | 209 | 209 |
| Shawnee | Kentucky | 1379 | 7 | 210 | 210 |
| Shawnee | Kentucky | 1379 | 8 | 205 | 205 |
| Shawnee | Kentucky | 1379 | 9 | 192 | 192 |
| Shawnee | Kentucky | 1379 | 10 | | |
| Smith Generating Facility | Kentucky | 54 | SCT1 | 8 | 8 |
| Smith Generating Facility | Kentucky | 54 | SCT10 | 5 | 5 |
| Smith Generating Facility | Kentucky | 54 | SCT2 | 8 | 8 |
| Smith Generating Facility | Kentucky | 54 | SCT3 | 12 | 12 |
| Smith Generating Facility | Kentucky | 54 | SCT4 | 13 | 13 |
| Smith Generating Facility | Kentucky | 54 | SCT5 | 8 | 8 |
| Smith Generating Facility | Kentucky | 54 | SCT6 | 8 | 8 |
| Smith Generating Facility | Kentucky | 54 | SCT7 | 10 | 10 |
| Smith Generating Facility | Kentucky | 54 | SCT9 | 4 | 4 |
| Trimble County | Kentucky | 6071 | 1 | 817 | 817 |
| Trimble County | Kentucky | 6071 | 2 | 431 | 431 |
| Trimble County | Kentucky | 6071 | 5 | 24 | 24 |
| Trimble County | Kentucky | 6071 | 6 | 21 | 21 |
| Trimble County | Kentucky | 6071 | 7 | 15 | 15 |
| Trimble County | Kentucky | 6071 | 8 | 10 | 10 |
| Trimble County | Kentucky | 6071 | 9 | 19 | 19 |
| Trimble County | Kentucky | 6071 | 10 | 13 | 13 |
| Tyrone | Kentucky | 1361 | 5 | 0 | 0 |
| William C. Dale | Kentucky | 1385 | 1 | 11 | 11 |
| William C. Dale | Kentucky | 1385 | 2 | 11 | 11 |
| William C. Dale | Kentucky | 1385 | 3 | 47 | 47 |
| William C. Dale | Kentucky | 1385 | 4 | 49 | 49 |
| Acadia Power Station | Louisiana | 55173 | CT1 | 34 | 34 |
| Acadia Power Station | Louisiana | 55173 | CT2 | 54 | 54 |
| Acadia Power Station | Louisiana | 55173 | CT3 | 44 | 44 |
| Acadia Power Station | Louisiana | 55173 | CT4 | 40 | 40 |
| Arsenal Hill Power Plant | Louisiana | 1416 | 5A | 43 | 43 |
| Arsenal Hill Power Plant | Louisiana | 1416 | CTG-6A | 33 | 33 |
| Arsenal Hill Power Plant | Louisiana | 1416 | CTG-6B | 32 | 32 |
| Bayou Cove Peaking Power Plant | Louisiana | 55433 | CTG-1 | 3 | 3 |
| Bayou Cove Peaking Power Plant | Louisiana | 55433 | CTG-2 | 3 | 3 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bayou Cove Peaking Power Plant | Louisiana | 55433 | CTG-3 | 3 | 3 |
| Bayou Cove Peaking Power Plant | Louisiana | 55433 | CTG-4 | 4 | 4 |
| Big Cajun 1 | Louisiana | 1464 | 1B1 | 0 | 0 |
| Big Cajun 1 | Louisiana | 1464 | 1B2 | 3 | 3 |
| Big Cajun 1 | Louisiana | 1464 | CTG1 | 21 | 21 |
| Big Cajun 1 | Louisiana | 1464 | CTG2 | 16 | 16 |
| Big Cajun 2 | Louisiana | 6055 | 2B1 | 1,266 | 1,266 |
| Big Cajun 2 | Louisiana | 6055 | 2B2 | 1,296 | 1,296 |
| Big Cajun 2 | Louisiana | 6055 | 2B3 | 1,252 | 1,252 |
| Brame Energy Center | Louisiana | 6190 | 1 | 332 | 332 |
| Brame Energy Center | Louisiana | 6190 | 2 | 995 | 995 |
| Brame Energy Center | Louisiana | 6190 | 3-1 | 318 | 318 |
| Brame Energy Center | Louisiana | 6190 | 3-2 | 339 | 339 |
| Calcasieu Plant | Louisiana | 55165 | GTG1 | 64 | 64 |
| Calcasieu Plant | Louisiana | 55165 | GTG2 | 43 | 43 |
| Carville Energy Center | Louisiana | 55404 | COG01 | 99 | 99 |
| Carville Energy Center | Louisiana | 55404 | COG02 | 89 | 89 |
| Coughlin Power Station | Louisiana | 1396 | 6-1 | 58 | 58 |
| Coughlin Power Station | Louisiana | 1396 | 7-1 | 63 | 63 |
| Coughlin Power Station | Louisiana | 1396 | 7-2 | 48 | 48 |
| D G Hunter | Louisiana | 6558 | 3 | 0 | 0 |
| D G Hunter | Louisiana | 6558 | 4 | 6 | 6 |
| Doc Bonin | Louisiana | 1443 | 1 | 0 | 0 |
| Doc Bonin | Louisiana | 1443 | 2 | 69 | 69 |
| Doc Bonin | Louisiana | 1443 | 3 | 145 | 145 |
| Dolet Hills Power Station | Louisiana | 51 | 1 | 1,606 | 1,606 |
| Hargis-Hebert Electric Generating Statio | Louisiana | 56283 | U-1 | 18 | 18 |
| Hargis-Hebert Electric Generating Statio | Louisiana | 56283 | U-2 | 15 | 15 |
| Houma | Louisiana | 1439 | 15 | 10 | 10 |
| Houma | Louisiana | 1439 | 16 | 16 | 16 |
| Lieberman Power Plant | Louisiana | 1417 | 3 | 38 | 38 |
| Lieberman Power Plant | Louisiana | 1417 | 4 | 32 | 32 |
| Little Gypsy | Louisiana | 1402 | 1 | 119 | 119 |
| Little Gypsy | Louisiana | 1402 | 2 | 222 | 222 |
| Little Gypsy | Louisiana | 1402 | 3 | 520 | 520 |
| Louisiana 1 | Louisiana | 1391 | 1A | 68 | 68 |
| Louisiana 1 | Louisiana | 1391 | 2A | 68 | 68 |
| Louisiana 1 | Louisiana | 1391 | 3A | 74 | 74 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Louisiana 1 | Louisiana | 1391 | 4A | 375 | 375 |
| Louisiana 1 | Louisiana | 1391 | 5A | 133 | 133 |
| Michoud | Louisiana | 1409 | 1 | | |
| Michoud | Louisiana | 1409 | 2 | 245 | 245 |
| Michoud | Louisiana | 1409 | 3 | 660 | 660 |
| Morgan City Electrical Gen Facility | Louisiana | 1449 | 4 | 26 | 26 |
| Natchitoches | Louisiana | 1450 | 10 | | |
| Nelson Industrial Steam Company | Louisiana | 50030 | 1A | 281 | 281 |
| Nelson Industrial Steam Company | Louisiana | 50030 | 2A | 288 | 288 |
| Ninemile Point | Louisiana | 1403 | 1 | 1 | 1 |
| Ninemile Point | Louisiana | 1403 | 2 | | |
| Ninemile Point | Louisiana | 1403 | 3 | 85 | 85 |
| Ninemile Point | Louisiana | 1403 | 4 | 877 | 877 |
| Ninemile Point | Louisiana | 1403 | 5 | 994 | 994 |
| Ninemile Point | Louisiana | 1403 | 6A | 37 | 37 |
| Ninemile Point | Louisiana | 1403 | 6B | 36 | 36 |
| Ouachita Plant | Louisiana | 55467 | CTGEN1 | 36 | 36 |
| Ouachita Plant | Louisiana | 55467 | CTGEN2 | 36 | 36 |
| Ouachita Plant | Louisiana | 55467 | CTGEN3 | 34 | 34 |
| Perryville Power Station | Louisiana | 55620 | 1-1 | 37 | 37 |
| Perryville Power Station | Louisiana | 55620 | 1-2 | 36 | 36 |
| Perryville Power Station | Louisiana | 55620 | 2-1 | 5 | 5 |
| Plaquemine Cogen Facility | Louisiana | 55419 | 500 | 52 | 52 |
| Plaquemine Cogen Facility | Louisiana | 55419 | 600 | 50 | 50 |
| Plaquemine Cogen Facility | Louisiana | 55419 | 700 | 53 | 53 |
| Plaquemine Cogen Facility | Louisiana | 55419 | 800 | 59 | 59 |
| R S Cogen | Louisiana | 55117 | RS-5 | 161 | 161 |
| R S Cogen | Louisiana | 55117 | RS-6 | 190 | 190 |
| R S Nelson | Louisiana | 1393 | 3 | 91 | 91 |
| R S Nelson | Louisiana | 1393 | 4 | 568 | 568 |
| R S Nelson | Louisiana | 1393 | 6 | 1,367 | 1,367 |
| Sterlington | Louisiana | 1404 | 10 | | |
| Sterlington | Louisiana | 1404 | 7AB | 2 | 2 |
| Sterlington | Louisiana | 1404 | 7C | 2 | 2 |
| T J Labbe Electric Generating Station | Louisiana | 56108 | U-1 | 29 | 29 |
| T J Labbe Electric Generating Station | Louisiana | 56108 | U-2 | 11 | 11 |
| Taft Cogeneration Facility | Louisiana | 55089 | CT1 | 85 | 85 |
| Taft Cogeneration Facility | Louisiana | 55089 | CT2 | 89 | 89 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Taft Cogeneration Facility | Louisiana | 55089 | CT3 | 86 | 86 |
| Teche Power Station | Louisiana | 1400 | 2 | | |
| Teche Power Station | Louisiana | 1400 | 3 | 247 | 247 |
| Teche Power Station | Louisiana | 1400 | 4 | 2 | 2 |
| Waterford 1 & 2 | Louisiana | 8056 | 1 | 250 | 250 |
| Waterford 1 & 2 | Louisiana | 8056 | 2 | 323 | 323 |
| Waterford 1 & 2 | Louisiana | 8056 | 4 | 2 | 2 |
| Willow Glen | Louisiana | 1394 | 1 | 69 | 69 |
| Willow Glen | Louisiana | 1394 | 2 | 141 | 141 |
| Willow Glen | Louisiana | 1394 | 3 | | |
| Willow Glen | Louisiana | 1394 | 4 | 496 | 496 |
| Willow Glen | Louisiana | 1394 | 5 | | |
| AES Warrior Run | Maryland | 10678 | 001 | 215 | 215 |
| Brandon Shores | Maryland | 602 | 1 | 474 | 474 |
| Brandon Shores | Maryland | 602 | 2 | 487 | 487 |
| C P Crane | Maryland | 1552 | 1 | 83 | 83 |
| C P Crane | Maryland | 1552 | 2 | 104 | 104 |
| Chalk Point | Maryland | 1571 | 1 | 203 | 203 |
| Chalk Point | Maryland | 1571 | 2 | 204 | 204 |
| Chalk Point | Maryland | 1571 | 3 | 171 | 171 |
| Chalk Point | Maryland | 1571 | 4 | 207 | 207 |
| Chalk Point | Maryland | 1571 | **GT3 | 3 | 3 |
| Chalk Point | Maryland | 1571 | **GT4 | 3 | 3 |
| Chalk Point | Maryland | 1571 | **GT5 | 4 | 4 |
| Chalk Point | Maryland | 1571 | **GT6 | 5 | 5 |
| Chalk Point | Maryland | 1571 | GT2 | 0 | 0 |
| Chalk Point | Maryland | 1571 | SMECO | 2 | 2 |
| Dickerson | Maryland | 1572 | 1 | 61 | 61 |
| Dickerson | Maryland | 1572 | 2 | 60 | 60 |
| Dickerson | Maryland | 1572 | 3 | 68 | 68 |
| Dickerson | Maryland | 1572 | GT2 | 20 | 20 |
| Dickerson | Maryland | 1572 | GT3 | 19 | 19 |
| Gould Street | Maryland | 1553 | 3 | 12 | 12 |
| Herbert A Wagner | Maryland | 1554 | 1 | 17 | 17 |
| Herbert A Wagner | Maryland | 1554 | 2 | 66 | 66 |
| Herbert A Wagner | Maryland | 1554 | 3 | 200 | 200 |
| Herbert A Wagner | Maryland | 1554 | 4 | 7 | 7 |
| Morgantown | Maryland | 1573 | 1 | 353 | 353 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Morgantown | Maryland | 1573 | 2 | 361 | 361 |
| Morgantown | Maryland | 1573 | GT3 | 1 | 1 |
| Morgantown | Maryland | 1573 | GT4 | 1 | 1 |
| Morgantown | Maryland | 1573 | GT5 | 1 | 1 |
| Morgantown | Maryland | 1573 | GT6 | 1 | 1 |
| Panda Brandywine | Maryland | 54832 | 1 | 32 | 32 |
| Panda Brandywine | Maryland | 54832 | 2 | 29 | 29 |
| Perryman | Maryland | 1556 | **51 | 36 | 36 |
| Perryman | Maryland | 1556 | CT1 | 1 | 1 |
| Perryman | Maryland | 1556 | CT2 | 1 | 1 |
| Perryman | Maryland | 1556 | CT3 | 1 | 1 |
| Perryman | Maryland | 1556 | CT4 | 1 | 1 |
| R. Paul Smith Power Station | Maryland | 1570 | 9 | 3 | 3 |
| R. Paul Smith Power Station | Maryland | 1570 | 11 | 22 | 22 |
| Riverside | Maryland | 1559 | 4 | 11 | 11 |
| Riverside | Maryland | 1559 | CT6 | 0 | 0 |
| Rock Springs Generating Facility | Maryland | 7835 | 1 | 22 | 22 |
| Rock Springs Generating Facility | Maryland | 7835 | 2 | 21 | 21 |
| Rock Springs Generating Facility | Maryland | 7835 | 3 | 35 | 35 |
| Rock Springs Generating Facility | Maryland | 7835 | 4 | 36 | 36 |
| Vienna | Maryland | 1564 | 8 | 4 | 4 |
| Westport | Maryland | 1560 | CT5 | 8 | 8 |
| 48th Street Peaking Station | Michigan | 7258 | 9 | 7 | 7 |
| 48th Street Peaking Station | Michigan | 7258 | **7 | 3 | 3 |
| 48th Street Peaking Station | Michigan | 7258 | **8 | 3 | 3 |
| B C Cobb | Michigan | 1695 | 1 | | |
| B C Cobb | Michigan | 1695 | 2 | | |
| B C Cobb | Michigan | 1695 | 3 | | |
| B C Cobb | Michigan | 1695 | 4 | 199 | 199 |
| B C Cobb | Michigan | 1695 | 5 | 204 | 204 |
| Belle River | Michigan | 6034 | 1 | 875 | 875 |
| Belle River | Michigan | 6034 | 2 | 926 | 926 |
| Belle River | Michigan | 6034 | CTG121 | 8 | 8 |
| Belle River | Michigan | 6034 | CTG122 | 10 | 10 |
| Belle River | Michigan | 6034 | CTG131 | 8 | 8 |
| Cadillac Renewable Energy | Michigan | 54415 | EUBLR | 64 | 64 |
| Conners Creek | Michigan | 1726 | 15 | | |
| Conners Creek | Michigan | 1726 | 16 | | |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Conners Creek | Michigan | 1726 | 17 | | |
| Conners Creek | Michigan | 1726 | 18 | | |
| Dan E Karn | Michigan | 1702 | 1 | 258 | 258 |
| Dan E Karn | Michigan | 1702 | 2 | 327 | 327 |
| Dan E Karn | Michigan | 1702 | 3 | 37 | 37 |
| Dan E Karn | Michigan | 1702 | 4 | 27 | 27 |
| Dearborn Industrial Generation | Michigan | 55088 | BL1100 | 36 | 36 |
| Dearborn Industrial Generation | Michigan | 55088 | BL2100 | 24 | 24 |
| Dearborn Industrial Generation | Michigan | 55088 | BL3100 | 24 | 24 |
| Dearborn Industrial Generation | Michigan | 55088 | GT2100 | 64 | 64 |
| Dearborn Industrial Generation | Michigan | 55088 | GT3100 | 68 | 68 |
| Dearborn Industrial Generation | Michigan | 55088 | GTP1 | 30 | 30 |
| Delray | Michigan | 1728 | CTG111 | 5 | 5 |
| Delray | Michigan | 1728 | CTG121 | 5 | 5 |
| DTE East China | Michigan | 55718 | 1 | 4 | 4 |
| DTE East China | Michigan | 55718 | 2 | 4 | 4 |
| DTE East China | Michigan | 55718 | 3 | 4 | 4 |
| DTE East China | Michigan | 55718 | 4 | 4 | 4 |
| DTE Pontiac North LLC | Michigan | 10111 | EUBHB9 | | |
| Eckert Station | Michigan | 1831 | 1 | 20 | 20 |
| Eckert Station | Michigan | 1831 | 2 | 22 | 22 |
| Eckert Station | Michigan | 1831 | 3 | 29 | 29 |
| Eckert Station | Michigan | 1831 | 4 | 85 | 85 |
| Eckert Station | Michigan | 1831 | 5 | 75 | 75 |
| Eckert Station | Michigan | 1831 | 6 | 95 | 95 |
| Endicott Generating | Michigan | 4259 | 1 | 76 | 76 |
| Erickson | Michigan | 1832 | 1 | 280 | 280 |
| Genesee Power Station | Michigan | 54751 | 01 | 53 | 53 |
| Grayling Generating Station | Michigan | 10822 | 1 | 64 | 64 |
| Greenwood | Michigan | 6035 | 1 | 154 | 154 |
| Greenwood | Michigan | 6035 | CTG111 | 5 | 5 |
| Greenwood | Michigan | 6035 | CTG112 | 6 | 6 |
| Greenwood | Michigan | 6035 | CTG121 | 6 | 6 |
| Hancock Peakers | Michigan | 1730 | CTG121 | 1 | 1 |
| Hancock Peakers | Michigan | 1730 | CTG122 | 0 | 0 |
| Harbor Beach | Michigan | 1731 | 1 | 26 | 26 |
| J B Sims | Michigan | 1825 | 3 | 54 | 54 |
| J C Weadock | Michigan | 1720 | 7 | 181 | 181 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| J C Weadock | Michigan | 1720 | 8 | 211 | 211 |
| J H Campbell | Michigan | 1710 | 1 | 386 | 386 |
| J H Campbell | Michigan | 1710 | 2 | 411 | 411 |
| J H Campbell | Michigan | 1710 | 3 | 1,306 | 1,306 |
| J R Whiting | Michigan | 1723 | 1 | 126 | 126 |
| J R Whiting | Michigan | 1723 | 2 | 136 | 136 |
| J R Whiting | Michigan | 1723 | 3 | 168 | 168 |
| Jackson MI Facility | Michigan | 55270 | 7EA | 38 | 38 |
| Jackson MI Facility | Michigan | 55270 | LM1 | 33 | 33 |
| Jackson MI Facility | Michigan | 55270 | LM2 | 33 | 33 |
| Jackson MI Facility | Michigan | 55270 | LM3 | 33 | 33 |
| Jackson MI Facility | Michigan | 55270 | LM4 | 33 | 33 |
| Jackson MI Facility | Michigan | 55270 | LM5 | 33 | 33 |
| Jackson MI Facility | Michigan | 55270 | LM6 | 33 | 33 |
| James De Young | Michigan | 1830 | 5 | 22 | 22 |
| Kalamazoo River Generating Station | Michigan | 55101 | 1 | 2 | 2 |
| Kalkaska Ct Project #1 | Michigan | 7984 | 1A | 6 | 6 |
| Kalkaska Ct Project #1 | Michigan | 7984 | 1B | 6 | 6 |
| Lansing BWL REO Town Plant | Michigan | 58427 | 100 | 9 | 9 |
| Lansing BWL REO Town Plant | Michigan | 58427 | 200 | 11 | 11 |
| Livingston Generating Station | Michigan | 55102 | 1 | 3 | 3 |
| Livingston Generating Station | Michigan | 55102 | 2 | 2 | 2 |
| Livingston Generating Station | Michigan | 55102 | 3 | 3 | 3 |
| Livingston Generating Station | Michigan | 55102 | 4 | 2 | 2 |
| Michigan Power Limited Partnership | Michigan | 54915 | 1 | 85 | 85 |
| Midland Cogeneration Venture | Michigan | 10745 | 003 | 73 | 73 |
| Midland Cogeneration Venture | Michigan | 10745 | 004 | 90 | 90 |
| Midland Cogeneration Venture | Michigan | 10745 | 005 | 79 | 79 |
| Midland Cogeneration Venture | Michigan | 10745 | 006 | 84 | 84 |
| Midland Cogeneration Venture | Michigan | 10745 | 007 | 84 | 84 |
| Midland Cogeneration Venture | Michigan | 10745 | 008 | 75 | 75 |
| Midland Cogeneration Venture | Michigan | 10745 | 009 | 73 | 73 |
| Midland Cogeneration Venture | Michigan | 10745 | 010 | 84 | 84 |
| Midland Cogeneration Venture | Michigan | 10745 | 011 | 70 | 70 |
| Midland Cogeneration Venture | Michigan | 10745 | 012 | 158 | 158 |
| Midland Cogeneration Venture | Michigan | 10745 | 013 | 80 | 80 |
| Midland Cogeneration Venture | Michigan | 10745 | 014 | 94 | 94 |
| Midland Cogeneration Venture | Michigan | 10745 | 016 | 7 | 7 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Midland Cogeneration Venture | Michigan | 10745 | 017 | 10 | 10 |
| Midland Cogeneration Venture | Michigan | 10745 | 018 | 8 | 8 |
| Midland Cogeneration Venture | Michigan | 10745 | 019 | 9 | 9 |
| Midland Cogeneration Venture | Michigan | 10745 | 020 | 3 | 3 |
| Midland Cogeneration Venture | Michigan | 10745 | 021 | 6 | 6 |
| Mistersky | Michigan | 1822 | 5 | | |
| Mistersky | Michigan | 1822 | 6 | | |
| Mistersky | Michigan | 1822 | 7 | | |
| Mistersky | Michigan | 1822 | GT-1 | 0 | 0 |
| Monroe | Michigan | 1733 | 1 | 987 | 987 |
| Monroe | Michigan | 1733 | 2 | 937 | 937 |
| Monroe | Michigan | 1733 | 3 | 912 | 912 |
| Monroe | Michigan | 1733 | 4 | 964 | 964 |
| New Covert Generating Project | Michigan | 55297 | 001 | 13 | 13 |
| New Covert Generating Project | Michigan | 55297 | 002 | 21 | 21 |
| New Covert Generating Project | Michigan | 55297 | 003 | 17 | 17 |
| Presque Isle | Michigan | 1769 | 5 | 75 | 75 |
| Presque Isle | Michigan | 1769 | 6 | 88 | 88 |
| Presque Isle | Michigan | 1769 | 7 | 104 | 104 |
| Presque Isle | Michigan | 1769 | 8 | 127 | 127 |
| Presque Isle | Michigan | 1769 | 9 | 122 | 122 |
| Renaissance Power | Michigan | 55402 | CT1 | 25 | 25 |
| Renaissance Power | Michigan | 55402 | CT2 | 21 | 21 |
| Renaissance Power | Michigan | 55402 | CT3 | 19 | 19 |
| Renaissance Power | Michigan | 55402 | CT4 | 21 | 21 |
| River Rouge | Michigan | 1740 | 1 | | |
| River Rouge | Michigan | 1740 | 2 | 250 | 250 |
| River Rouge | Michigan | 1740 | 3 | 312 | 312 |
| Shiras | Michigan | 1843 | 3 | 76 | 76 |
| St. Clair | Michigan | 1743 | 1 | 153 | 153 |
| St. Clair | Michigan | 1743 | 2 | 155 | 155 |
| St. Clair | Michigan | 1743 | 3 | 168 | 168 |
| St. Clair | Michigan | 1743 | 4 | 178 | 178 |
| St. Clair | Michigan | 1743 | 6 | 335 | 335 |
| St. Clair | Michigan | 1743 | 7 | 477 | 477 |
| Sumpter Plant | Michigan | 7972 | 1 | 5 | 5 |
| Sumpter Plant | Michigan | 7972 | 2 | 6 | 6 |
| Sumpter Plant | Michigan | 7972 | 3 | 6 | 6 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Sumpter Plant | Michigan | 7972 | 4 | 6 | 6 |
| TES Filer City Station | Michigan | 50835 | 1 | 69 | 69 |
| TES Filer City Station | Michigan | 50835 | 2 | 68 | 68 |
| Thetford | Michigan | 1719 | 1 | 0 | 0 |
| Thetford | Michigan | 1719 | 2 | 0 | 0 |
| Thetford | Michigan | 1719 | 3 | 0 | 0 |
| Thetford | Michigan | 1719 | 4 | 1 | 1 |
| Trenton Channel | Michigan | 1745 | 16 | 45 | 45 |
| Trenton Channel | Michigan | 1745 | 17 | 58 | 58 |
| Trenton Channel | Michigan | 1745 | 18 | 54 | 54 |
| Trenton Channel | Michigan | 1745 | 19 | 55 | 55 |
| Trenton Channel | Michigan | 1745 | 9A | 577 | 577 |
| Wyandotte | Michigan | 1866 | 5 | 0 | 0 |
| Wyandotte | Michigan | 1866 | 7 | 30 | 30 |
| Wyandotte | Michigan | 1866 | 8 | 26 | 26 |
| Zeeland Generating Station | Michigan | 55087 | CC1 | 22 | 22 |
| Zeeland Generating Station | Michigan | 55087 | CC2 | 26 | 26 |
| Zeeland Generating Station | Michigan | 55087 | CC3 | 26 | 26 |
| Zeeland Generating Station | Michigan | 55087 | CC4 | 26 | 26 |
| Attala Generating Plant | Mississippi | 55220 | A01 | 26 | 26 |
| Attala Generating Plant | Mississippi | 55220 | A02 | 30 | 30 |
| Batesville Generation Facility | Mississippi | 55063 | 1 | 68 | 68 |
| Batesville Generation Facility | Mississippi | 55063 | 2 | 70 | 70 |
| Batesville Generation Facility | Mississippi | 55063 | 3 | 74 | 74 |
| Baxter Wilson | Mississippi | 2050 | 1 | 341 | 341 |
| Baxter Wilson | Mississippi | 2050 | 2 | 428 | 428 |
| Caledonia | Mississippi | 55197 | AA-001 | 26 | 26 |
| Caledonia | Mississippi | 55197 | AA-002 | 28 | 28 |
| Caledonia | Mississippi | 55197 | AA-003 | 26 | 26 |
| Chevron Cogenerating Station | Mississippi | 2047 | 5 | 113 | 113 |
| Choctaw County Gen | Mississippi | 55706 | CTG1 | | |
| Choctaw County Gen | Mississippi | 55706 | CTG2 | 28 | 28 |
| Choctaw County Gen | Mississippi | 55706 | CTG3 | 27 | 27 |
| Choctaw Gas Generation, LLC | Mississippi | 55694 | AA-001 | 38 | 38 |
| Choctaw Gas Generation, LLC | Mississippi | 55694 | AA-002 | 35 | 35 |
| Crossroads Energy Center (CPU) | Mississippi | 55395 | CT01 | 10 | 10 |
| Crossroads Energy Center (CPU) | Mississippi | 55395 | CT02 | 10 | 10 |
| Crossroads Energy Center (CPU) | Mississippi | 55395 | CT03 | 9 | 9 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Crossroads Energy Center (CPU) | Mississippi | 55395 | CT04 | 12 | 12 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 1 | 563 | 563 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 2 | 556 | 556 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 3A | 23 | 23 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 3B | 22 | 22 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 4A | 27 | 27 |
| Daniel Electric Generating Plant | Mississippi | 6073 | 4B | 23 | 23 |
| David M Ratcliffe | Mississippi | 57037 | AB-001 | 55 | 55 |
| David M Ratcliffe | Mississippi | 57037 | AB-002 | 52 | 52 |
| Delta | Mississippi | 2051 | 1 | | |
| Delta | Mississippi | 2051 | 2 | | |
| Gerald Andrus | Mississippi | 8054 | 1 | 572 | 572 |
| Hinds Energy Facility | Mississippi | 55218 | H01 | 23 | 23 |
| Hinds Energy Facility | Mississippi | 55218 | H02 | 23 | 23 |
| Kemper County | Mississippi | 7960 | KCT1 | 8 | 8 |
| Kemper County | Mississippi | 7960 | KCT2 | 7 | 7 |
| Kemper County | Mississippi | 7960 | KCT3 | 11 | 11 |
| Kemper County | Mississippi | 7960 | KCT4 | 6 | 6 |
| Magnolia Facility | Mississippi | 55451 | CTG-1 | 32 | 32 |
| Magnolia Facility | Mississippi | 55451 | CTG-2 | 37 | 37 |
| Magnolia Facility | Mississippi | 55451 | CTG-3 | 37 | 37 |
| Moselle Generating Plant | Mississippi | 2070 | 1 | 19 | 19 |
| Moselle Generating Plant | Mississippi | 2070 | 2 | 29 | 29 |
| Moselle Generating Plant | Mississippi | 2070 | 3 | 15 | 15 |
| Moselle Generating Plant | Mississippi | 2070 | 5 | 2 | 2 |
| Moselle Generating Plant | Mississippi | 2070 | 6 | 8 | 8 |
| Moselle Generating Plant | Mississippi | 2070 | 7 | 12 | 12 |
| Moselle Generating Plant | Mississippi | 2070 | **4 | 3 | 3 |
| R D Morrow Senior Generating Plant | Mississippi | 6061 | 1 | 187 | 187 |
| R D Morrow Senior Generating Plant | Mississippi | 6061 | 2 | 237 | 237 |
| Red Hills Generation Facility | Mississippi | 55076 | AA001 | 413 | 413 |
| Red Hills Generation Facility | Mississippi | 55076 | AA002 | 464 | 464 |
| Rex Brown | Mississippi | 2053 | 3 | 12 | 12 |
| Rex Brown | Mississippi | 2053 | 4 | 105 | 105 |
| Silver Creek Generating Plant | Mississippi | 7988 | 1 | 9 | 9 |
| Silver Creek Generating Plant | Mississippi | 7988 | 2 | 9 | 9 |
| Silver Creek Generating Plant | Mississippi | 7988 | 3 | 8 | 8 |
| Southaven Combined Cycle | Mississippi | 55269 | AA-001 | 29 | 29 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Southaven Combined Cycle | Mississippi | 55269 | AA-002 | 32 | 32 |
| Southaven Combined Cycle | Mississippi | 55269 | AA-003 | 75 | 75 |
| Sweatt Electric Generating Plant | Mississippi | 2048 | 1 | 1 | 1 |
| Sweatt Electric Generating Plant | Mississippi | 2048 | 2 | 1 | 1 |
| Sweatt Electric Generating Plant | Mississippi | 2048 | CTA | 1 | 1 |
| Sweatt Electric Generating Plant | Mississippi | 2048 | CTB | 1 | 1 |
| Sylvarena Generating Plant | Mississippi | 7989 | 1 | 14 | 14 |
| Sylvarena Generating Plant | Mississippi | 7989 | 2 | 13 | 13 |
| Sylvarena Generating Plant | Mississippi | 7989 | 3 | 14 | 14 |
| Watson Electric Generating Plant | Mississippi | 2049 | 1 | 5 | 5 |
| Watson Electric Generating Plant | Mississippi | 2049 | 2 | 5 | 5 |
| Watson Electric Generating Plant | Mississippi | 2049 | 3 | 20 | 20 |
| Watson Electric Generating Plant | Mississippi | 2049 | 4 | 285 | 285 |
| Watson Electric Generating Plant | Mississippi | 2049 | 5 | 683 | 683 |
| Watson Electric Generating Plant | Mississippi | 2049 | CTA | 1 | 1 |
| Watson Electric Generating Plant | Mississippi | 2049 | CTB | 1 | 1 |
| Asbury | Missouri | 2076 | 1 | 296 | 296 |
| Audrain Power Plant | Missouri | 55234 | CT1 | 2 | 2 |
| Audrain Power Plant | Missouri | 55234 | CT2 | 3 | 3 |
| Audrain Power Plant | Missouri | 55234 | CT3 | 2 | 2 |
| Audrain Power Plant | Missouri | 55234 | CT4 | 2 | 2 |
| Audrain Power Plant | Missouri | 55234 | CT5 | 2 | 2 |
| Audrain Power Plant | Missouri | 55234 | CT6 | 1 | 1 |
| Audrain Power Plant | Missouri | 55234 | CT7 | 2 | 2 |
| Audrain Power Plant | Missouri | 55234 | CT8 | 1 | 1 |
| Blue Valley | Missouri | 2132 | 3 | 22 | 22 |
| Chamois Power Plant | Missouri | 2169 | 2 | 71 | 71 |
| Chillicothe | Missouri | 2122 | GT1A | 1 | 1 |
| Chillicothe | Missouri | 2122 | GT1B | 0 | 0 |
| Chillicothe | Missouri | 2122 | GT2A | 0 | 0 |
| Chillicothe | Missouri | 2122 | GT2B | 0 | 0 |
| Columbia | Missouri | 2123 | 6 | 3 | 3 |
| Columbia | Missouri | 2123 | 7 | 18 | 18 |
| Columbia | Missouri | 2123 | 8 | 1 | 1 |
| Columbia Energy Center (MO) | Missouri | 55447 | CT01 | 1 | 1 |
| Columbia Energy Center (MO) | Missouri | 55447 | CT02 | 1 | 1 |
| Columbia Energy Center (MO) | Missouri | 55447 | CT03 | 2 | 2 |
| Columbia Energy Center (MO) | Missouri | 55447 | CT04 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Dogwood Energy Facility | Missouri | 55178 | CT-1 | 30 | 30 |
| Dogwood Energy Facility | Missouri | 55178 | CT-2 | 29 | 29 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 1 | 2 | 2 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 2 | 4 | 4 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 3A | 6 | 6 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 3B | 6 | 6 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 4A | 5 | 5 |
| Empire District Elec Co Energy Ctr | Missouri | 6223 | 4B | 5 | 5 |
| Essex Power Plant | Missouri | 7749 | 1 | 16 | 16 |
| Fairgrounds | Missouri | 2082 | CT01 | 1 | 1 |
| Greenwood Energy Center | Missouri | 6074 | 1 | 5 | 5 |
| Greenwood Energy Center | Missouri | 6074 | 2 | 5 | 5 |
| Greenwood Energy Center | Missouri | 6074 | 3 | 4 | 4 |
| Greenwood Energy Center | Missouri | 6074 | 4 | 5 | 5 |
| Hawthorn | Missouri | 2079 | 6 | | |
| Hawthorn | Missouri | 2079 | 7 | 2 | 2 |
| Hawthorn | Missouri | 2079 | 8 | 2 | 2 |
| Hawthorn | Missouri | 2079 | 9 | 17 | 17 |
| Hawthorn | Missouri | 2079 | 5A | 697 | 697 |
| Higginsville Municipal Power Plant | Missouri | 2131 | 4A | 1 | 1 |
| Higginsville Municipal Power Plant | Missouri | 2131 | 4B | 0 | 0 |
| Holden Power Plant | Missouri | 7848 | 1 | 5 | 5 |
| Holden Power Plant | Missouri | 7848 | 2 | 8 | 8 |
| Holden Power Plant | Missouri | 7848 | 3 | 6 | 6 |
| Howard Bend | Missouri | 2102 | CT1A | 0 | 0 |
| Howard Bend | Missouri | 2102 | CT1B | 0 | 0 |
| Iatan | Missouri | 6065 | 1 | 971 | 971 |
| Iatan | Missouri | 6065 | 2 | 718 | 718 |
| James River | Missouri | 2161 | 3 | 36 | 36 |
| James River | Missouri | 2161 | 4 | 53 | 53 |
| James River | Missouri | 2161 | 5 | 108 | 108 |
| James River | Missouri | 2161 | **GT1 | 10 | 10 |
| James River | Missouri | 2161 | **GT2 | 9 | 9 |
| John Twitty Energy Center | Missouri | 6195 | 2 | 281 | 281 |
| Labadie | Missouri | 2103 | 1 | 802 | 802 |
| Labadie | Missouri | 2103 | 2 | 793 | 793 |
| Labadie | Missouri | 2103 | 3 | 799 | 799 |
| Labadie | Missouri | 2103 | 4 | 831 | 831 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Lake Road | Missouri | 2098 | 6 | 101 | 101 |
| Lake Road | Missouri | 2098 | GT5 | 4 | 4 |
| McCartney Generating Station | Missouri | 7903 | MGS1A | 3 | 3 |
| McCartney Generating Station | Missouri | 7903 | MGS1B | 5 | 5 |
| McCartney Generating Station | Missouri | 7903 | MGS2A | 5 | 5 |
| McCartney Generating Station | Missouri | 7903 | MGS2B | 5 | 5 |
| Meramec | Missouri | 2104 | 1 | 172 | 172 |
| Meramec | Missouri | 2104 | 2 | 166 | 166 |
| Meramec | Missouri | 2104 | 3 | 323 | 323 |
| Meramec | Missouri | 2104 | 4 | 404 | 404 |
| Meramec | Missouri | 2104 | CT01 | 0 | 0 |
| Meramec | Missouri | 2104 | CT2A | 2 | 2 |
| Meramec | Missouri | 2104 | CT2B | 1 | 1 |
| Mexico | Missouri | 6650 | CT01 | 0 | 0 |
| Moberly | Missouri | 6651 | CT01 | 0 | 0 |
| Montrose | Missouri | 2080 | 1 | 216 | 216 |
| Montrose | Missouri | 2080 | 2 | 203 | 203 |
| Montrose | Missouri | 2080 | 3 | 212 | 212 |
| Moreau | Missouri | 6652 | CT01 | 1 | 1 |
| New Madrid Power Plant | Missouri | 2167 | 1 | 717 | 717 |
| New Madrid Power Plant | Missouri | 2167 | 2 | 742 | 742 |
| Nodaway Power Plant | Missouri | 7754 | 1 | 2 | 2 |
| Nodaway Power Plant | Missouri | 7754 | 2 | 3 | 3 |
| Northeast Generating Station | Missouri | 2081 | 11 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 12 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 13 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 14 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 15 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 16 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 17 | 0 | 0 |
| Northeast Generating Station | Missouri | 2081 | 18 | 0 | 0 |
| Peno Creek Energy Center | Missouri | 7964 | CT1A | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT1B | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT2A | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT2B | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT3A | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT3B | 4 | 4 |
| Peno Creek Energy Center | Missouri | 7964 | CT4A | 4 | 4 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Peno Creek Energy Center | Missouri | 7964 | CT4B | 4 | 4 |
| Ralph Green Station | Missouri | 2092 | 3 | 5 | 5 |
| Rush Island | Missouri | 6155 | 1 | 728 | 728 |
| Rush Island | Missouri | 6155 | 2 | 749 | 749 |
| Sibley | Missouri | 2094 | 1 | 47 | 47 |
| Sibley | Missouri | 2094 | 2 | 49 | 49 |
| Sibley | Missouri | 2094 | 3 | 365 | 365 |
| Sikeston | Missouri | 6768 | 1 | 385 | 385 |
| Sioux | Missouri | 2107 | 1 | 554 | 554 |
| Sioux | Missouri | 2107 | 2 | 513 | 513 |
| South Harper Peaking Facility | Missouri | 56151 | 1 | 16 | 16 |
| South Harper Peaking Facility | Missouri | 56151 | 2 | 17 | 17 |
| South Harper Peaking Facility | Missouri | 56151 | 3 | 16 | 16 |
| Southwest | Missouri | 6195 | 1 | 216 | 216 |
| Southwest | Missouri | 6195 | CT1A | 1 | 1 |
| Southwest | Missouri | 6195 | CT1B | 1 | 1 |
| Southwest | Missouri | 6195 | CT2A | 1 | 1 |
| Southwest | Missouri | 6195 | CT2B | 1 | 1 |
| St. Francis Power Plant | Missouri | 7604 | 1 | 21 | 21 |
| St. Francis Power Plant | Missouri | 7604 | 2 | 15 | 15 |
| State Line (MO) | Missouri | 7296 | 1 | 7 | 7 |
| State Line (MO) | Missouri | 7296 | 2-1 | 31 | 31 |
| State Line (MO) | Missouri | 7296 | 2-2 | 33 | 33 |
| Thomas Hill Energy Center | Missouri | 2168 | MB1 | 300 | 300 |
| Thomas Hill Energy Center | Missouri | 2168 | MB2 | 394 | 394 |
| Thomas Hill Energy Center | Missouri | 2168 | MB3 | 967 | 967 |
| Viaduct | Missouri | 2096 | CT01 | | |
| AES Red Oak | New Jersey | 55239 | 1 | 33 | 33 |
| AES Red Oak | New Jersey | 55239 | 2 | 34 | 34 |
| AES Red Oak | New Jersey | 55239 | 3 | 31 | 31 |
| B L England | New Jersey | 2378 | 1 | 15 | 15 |
| B L England | New Jersey | 2378 | 2 | 20 | 20 |
| B L England | New Jersey | 2378 | 3 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT1 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT2 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT3 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT4 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT5 | 3 | 3 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bayonne Energy Center | New Jersey | 56964 | GT6 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT7 | 3 | 3 |
| Bayonne Energy Center | New Jersey | 56964 | GT8 | 3 | 3 |
| Bayonne Plant Holding, LLC | New Jersey | 50497 | 001001 | 18 | 18 |
| Bayonne Plant Holding, LLC | New Jersey | 50497 | 002001 | 19 | 19 |
| Bayonne Plant Holding, LLC | New Jersey | 50497 | 004001 | 19 | 19 |
| Bergen | New Jersey | 2398 | 1101 | 47 | 47 |
| Bergen | New Jersey | 2398 | 1201 | 47 | 47 |
| Bergen | New Jersey | 2398 | 1301 | 52 | 52 |
| Bergen | New Jersey | 2398 | 1401 | 50 | 50 |
| Bergen | New Jersey | 2398 | 2101 | 17 | 17 |
| Bergen | New Jersey | 2398 | 2201 | 16 | 16 |
| Burlington Generating Station | New Jersey | 2399 | 121 | 3 | 3 |
| Burlington Generating Station | New Jersey | 2399 | 122 | 3 | 3 |
| Burlington Generating Station | New Jersey | 2399 | 123 | 3 | 3 |
| Burlington Generating Station | New Jersey | 2399 | 124 | 3 | 3 |
| Burlington Generating Station | New Jersey | 2399 | 12001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 14001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 16001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 18001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 28001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 30001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 32001 | 0 | 0 |
| Burlington Generating Station | New Jersey | 2399 | 34001 | 0 | 0 |
| Camden Plant Holding, LLC | New Jersey | 10751 | 002001 | 41 | 41 |
| Carlls Corner Energy Center | New Jersey | 2379 | 002001 | 3 | 3 |
| Carlls Corner Energy Center | New Jersey | 2379 | 003001 | 3 | 3 |
| Carneys Point | New Jersey | 10566 | 1001 | 53 | 53 |
| Carneys Point | New Jersey | 10566 | 1002 | 54 | 54 |
| Cedar Energy Station | New Jersey | 2380 | 002001 | 0 | 0 |
| Cedar Energy Station | New Jersey | 2380 | 003001 | 0 | 0 |
| Cedar Energy Station | New Jersey | 2380 | 004001 | 0 | 0 |
| Cumberland Energy Center | New Jersey | 5083 | 004001 | 6 | 6 |
| Cumberland Energy Center | New Jersey | 5083 | 05001 | 3 | 3 |
| Deepwater | New Jersey | 2384 | 1 | 4 | 4 |
| Deepwater | New Jersey | 2384 | 8 | 9 | 9 |
| Edison | New Jersey | 2400 | 1001 | 1 | 1 |
| Edison | New Jersey | 2400 | 3001 | 1 | 1 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Edison | New Jersey | 2400 | 5001 | 1 | 1 |
| Edison | New Jersey | 2400 | 7001 | 1 | 1 |
| Edison | New Jersey | 2400 | 9001 | 1 | 1 |
| Edison | New Jersey | 2400 | 11001 | 1 | 1 |
| Edison | New Jersey | 2400 | 13001 | 1 | 1 |
| Edison | New Jersey | 2400 | 15001 | 1 | 1 |
| Edison | New Jersey | 2400 | 17001 | 1 | 1 |
| Edison | New Jersey | 2400 | 19001 | 1 | 1 |
| Edison | New Jersey | 2400 | 21001 | 1 | 1 |
| Edison | New Jersey | 2400 | 23001 | 1 | 1 |
| EFS Parlin Holdings, LLC | New Jersey | 50799 | 001001 | 8 | 8 |
| EFS Parlin Holdings, LLC | New Jersey | 50799 | 003001 | 8 | 8 |
| Elmwood Park Power - LLC | New Jersey | 50852 | 002001 | 10 | 10 |
| Essex | New Jersey | 2401 | 2001 | 2 | 2 |
| Essex | New Jersey | 2401 | 4001 | 1 | 1 |
| Essex | New Jersey | 2401 | 10001 | 1 | 1 |
| Essex | New Jersey | 2401 | 12001 | 1 | 1 |
| Essex | New Jersey | 2401 | 14001 | 1 | 1 |
| Essex | New Jersey | 2401 | 16001 | 1 | 1 |
| Essex | New Jersey | 2401 | 18001 | 1 | 1 |
| Essex | New Jersey | 2401 | 20001 | 1 | 1 |
| Essex | New Jersey | 2401 | 22001 | 1 | 1 |
| Essex | New Jersey | 2401 | 24001 | 1 | 1 |
| Essex | New Jersey | 2401 | 26001 | 1 | 1 |
| Essex | New Jersey | 2401 | 28001 | 1 | 1 |
| Essex | New Jersey | 2401 | 35001 | 3 | 3 |
| Forked River | New Jersey | 7138 | 002001 | 0 | 0 |
| Forked River | New Jersey | 7138 | 003001 | 0 | 0 |
| Gilbert Generating Station | New Jersey | 2393 | 04 | 2 | 2 |
| Gilbert Generating Station | New Jersey | 2393 | 05 | 2 | 2 |
| Gilbert Generating Station | New Jersey | 2393 | 06 | 2 | 2 |
| Gilbert Generating Station | New Jersey | 2393 | 07 | 2 | 2 |
| Gilbert Generating Station | New Jersey | 2393 | 9 | 1 | 1 |
| Howard M Down | New Jersey | 2434 | U11 | 4 | 4 |
| Hudson Generating Station | New Jersey | 2403 | 1 | 4 | 4 |
| Hudson Generating Station | New Jersey | 2403 | 2 | 198 | 198 |
| Kearny Generating Station | New Jersey | 2404 | 121 | 5 | 5 |
| Kearny Generating Station | New Jersey | 2404 | 122 | 5 | 5 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Kearny Generating Station | New Jersey | 2404 | 123 | 5 | 5 |
| Kearny Generating Station | New Jersey | 2404 | 124 | 5 | 5 |
| Kearny Generating Station | New Jersey | 2404 | 131 | 2 | 2 |
| Kearny Generating Station | New Jersey | 2404 | 132 | 2 | 2 |
| Kearny Generating Station | New Jersey | 2404 | 133 | 2 | 2 |
| Kearny Generating Station | New Jersey | 2404 | 134 | 1 | 1 |
| Kearny Generating Station | New Jersey | 2404 | 141 | 2 | 2 |
| Kearny Generating Station | New Jersey | 2404 | 142 | 2 | 2 |
| Kearny Generating Station | New Jersey | 2404 | 16001 | 1 | 1 |
| Kearny Generating Station | New Jersey | 2404 | 17001 | 1 | 1 |
| Lakewood Cogeneration | New Jersey | 54640 | 001001 | 23 | 23 |
| Lakewood Cogeneration | New Jersey | 54640 | 002001 | 35 | 35 |
| Linden Cogeneration Facility | New Jersey | 50006 | 004001 | 13 | 13 |
| Linden Cogeneration Facility | New Jersey | 50006 | 005001 | 35 | 35 |
| Linden Cogeneration Facility | New Jersey | 50006 | 006001 | 35 | 35 |
| Linden Cogeneration Facility | New Jersey | 50006 | 007001 | 35 | 35 |
| Linden Cogeneration Facility | New Jersey | 50006 | 008001 | 38 | 38 |
| Linden Cogeneration Facility | New Jersey | 50006 | 009001 | 35 | 35 |
| Linden Generating Station | New Jersey | 2406 | 5 | 4 | 4 |
| Linden Generating Station | New Jersey | 2406 | 6 | 4 | 4 |
| Linden Generating Station | New Jersey | 2406 | 7 | 4 | 4 |
| Linden Generating Station | New Jersey | 2406 | 8 | 3 | 3 |
| Linden Generating Station | New Jersey | 2406 | 1101 | 22 | 22 |
| Linden Generating Station | New Jersey | 2406 | 1201 | 19 | 19 |
| Linden Generating Station | New Jersey | 2406 | 2101 | 17 | 17 |
| Linden Generating Station | New Jersey | 2406 | 2201 | 21 | 21 |
| Logan Generating Plant | New Jersey | 10043 | 1001 | 125 | 125 |
| Mercer Generating Station | New Jersey | 2408 | 1 | 51 | 51 |
| Mercer Generating Station | New Jersey | 2408 | 2 | 41 | 41 |
| Mercer Generating Station | New Jersey | 2408 | 7001 | 0 | 0 |
| Mickleton Energy Center | New Jersey | 8008 | 001001 | 4 | 4 |
| Middle Energy Center | New Jersey | 2382 | 005001 | 0 | 0 |
| Newark Bay Cogen | New Jersey | 50385 | 1001 | 17 | 17 |
| Newark Bay Cogen | New Jersey | 50385 | 2001 | 15 | 15 |
| North Jersey Energy Associates | New Jersey | 10308 | 1001 | 78 | 78 |
| North Jersey Energy Associates | New Jersey | 10308 | 1002 | 81 | 81 |
| Ocean Peaking Power, LP | New Jersey | 55938 | OPP3 | 24 | 24 |
| Ocean Peaking Power, LP | New Jersey | 55938 | OPP4 | 24 | 24 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Pedricktown Cogeneration Plant | New Jersey | 10099 | 001001 | 32 | 32 |
| Salem | New Jersey | 2410 | 2001 | 0 | 0 |
| Sayreville | New Jersey | 2390 | 012001 | 0 | 0 |
| Sayreville | New Jersey | 2390 | 014001 | 0 | 0 |
| Sayreville | New Jersey | 2390 | 015001 | 0 | 0 |
| Sayreville | New Jersey | 2390 | 016001 | 1 | 1 |
| Sewaren Generating Station | New Jersey | 2411 | 1 | 5 | 5 |
| Sewaren Generating Station | New Jersey | 2411 | 2 | 5 | 5 |
| Sewaren Generating Station | New Jersey | 2411 | 3 | 3 | 3 |
| Sewaren Generating Station | New Jersey | 2411 | 4 | 5 | 5 |
| Sewaren Generating Station | New Jersey | 2411 | 12001 | 0 | 0 |
| Sherman Avenue | New Jersey | 7288 | 1 | 6 | 6 |
| Sunoco Power Generation, LLC | New Jersey | 50561 | 0001 | 23 | 23 |
| Sunoco Power Generation, LLC | New Jersey | 50561 | 0002 | 12 | 12 |
| Werner | New Jersey | 2385 | 009001 | 0 | 0 |
| Werner | New Jersey | 2385 | 010001 | 0 | 0 |
| Werner | New Jersey | 2385 | 011001 | 0 | 0 |
| Werner | New Jersey | 2385 | 012001 | 0 | 0 |
| West Deptford Energy Station | New Jersey | 56963 | E101 | 19 | 19 |
| West Deptford Energy Station | New Jersey | 56963 | E102 | 21 | 21 |
| West Station | New Jersey | 6776 | 002001 | 0 | 0 |
| 23rd and 3rd | New York | 7910 | 2301 | 2 | 2 |
| 23rd and 3rd | New York | 7910 | 2302 | 1 | 1 |
| AES Cayuga, LLC | New York | 2535 | 1 | 69 | 69 |
| AES Cayuga, LLC | New York | 2535 | 2 | 217 | 217 |
| AES Greenidge | New York | 2527 | 4 | 0 | 0 |
| AES Greenidge | New York | 2527 | 5 | 0 | 0 |
| AES Greenidge | New York | 2527 | 6 | 0 | 0 |
| AES Somerset (Kintigh) | New York | 6082 | 1 | 393 | 393 |
| AES Westover (Goudey) | New York | 2526 | 13 | 0 | 0 |
| AG - Energy | New York | 10803 | 1 | 0 | 0 |
| AG - Energy | New York | 10803 | 2 | 0 | 0 |
| Allegany Station No. 133 | New York | 10619 | 00001 | 2 | 2 |
| Arthur Kill | New York | 2490 | 20 | 136 | 136 |
| Arthur Kill | New York | 2490 | 30 | 87 | 87 |
| Astoria Energy | New York | 55375 | CT1 | 9 | 9 |
| Astoria Energy | New York | 55375 | CT2 | 13 | 13 |
| Astoria Energy | New York | 55375 | CT3 | 14 | 14 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Astoria Energy | New York | 55375 | CT4 | 12 | 12 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-1A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-1B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-2A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-2B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-3A | 2 | 2 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-3B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-4A | 2 | 2 |
| Astoria Gas Turbine Power | New York | 55243 | CT2-4B | 2 | 2 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-1A | 2 | 2 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-1B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-2A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-2B | 4 | 4 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-3A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-3B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-4A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT3-4B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-1A | 4 | 4 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-1B | 4 | 4 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-2A | 4 | 4 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-2B | 4 | 4 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-3A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-3B | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-4A | 3 | 3 |
| Astoria Gas Turbine Power | New York | 55243 | CT4-4B | 4 | 4 |
| Astoria Generating Station | New York | 8906 | 20 | 1 | 1 |
| Astoria Generating Station | New York | 8906 | 31RH | 19 | 19 |
| Astoria Generating Station | New York | 8906 | 32SH | 16 | 16 |
| Astoria Generating Station | New York | 8906 | 41SH | 0 | 0 |
| Astoria Generating Station | New York | 8906 | 42RH | 0 | 0 |
| Astoria Generating Station | New York | 8906 | 51RH | 57 | 57 |
| Astoria Generating Station | New York | 8906 | 52SH | 56 | 56 |
| Athens Generating Company | New York | 55405 | 1 | 12 | 12 |
| Athens Generating Company | New York | 55405 | 2 | 16 | 16 |
| Athens Generating Company | New York | 55405 | 3 | 12 | 12 |
| Batavia Energy | New York | 54593 | 1 | 11 | 11 |
| Bayswater Peaking Facility | New York | 55699 | 1 | 4 | 4 |
| Bayswater Peaking Facility | New York | 55699 | 2 | 1 | 1 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bethlehem Energy Center (Albany) | New York | 2539 | 10001 | 12 | 12 |
| Bethlehem Energy Center (Albany) | New York | 2539 | 10002 | 12 | 12 |
| Bethlehem Energy Center (Albany) | New York | 2539 | 10003 | 12 | 12 |
| Bethpage Energy Center | New York | 50292 | GT1 | 20 | 20 |
| Bethpage Energy Center | New York | 50292 | GT2 | 22 | 22 |
| Bethpage Energy Center | New York | 50292 | GT3 | 2 | 2 |
| Bethpage Energy Center | New York | 50292 | GT4 | 2 | 2 |
| Binghamton Cogen Plant | New York | 55600 | 1 | 2 | 2 |
| Black River Generation, LLC | New York | 10464 | E0001 | 34 | 34 |
| Black River Generation, LLC | New York | 10464 | E0002 | 42 | 42 |
| Black River Generation, LLC | New York | 10464 | E0003 | 33 | 33 |
| Bowline Generating Station | New York | 2625 | 1 | 244 | 244 |
| Bowline Generating Station | New York | 2625 | 2 | 24 | 24 |
| Brentwood | New York | 7912 | BW01 | 1 | 1 |
| Brooklyn Navy Yard Cogeneration | New York | 54914 | 1 | 9 | 9 |
| Brooklyn Navy Yard Cogeneration | New York | 54914 | 2 | 10 | 10 |
| Caithness Long Island Energy Center | New York | 56234 | 0001 | 17 | 17 |
| Carr Street Generating Station | New York | 50978 | A | 3 | 3 |
| Carr Street Generating Station | New York | 50978 | B | 3 | 3 |
| Carthage Energy | New York | 10620 | 1 | 2 | 2 |
| Castleton Power, LLC | New York | 10190 | 1 | 25 | 25 |
| Charles Poletti | New York | 2491 | 001 | 0 | 0 |
| Dynegy Danskammer | New York | 2480 | 1 | 7 | 7 |
| Dynegy Danskammer | New York | 2480 | 2 | 6 | 6 |
| Dynegy Danskammer | New York | 2480 | 3 | 2 | 2 |
| Dynegy Danskammer | New York | 2480 | 4 | 10 | 10 |
| Dynegy Roseton | New York | 8006 | 1 | 30 | 30 |
| Dynegy Roseton | New York | 8006 | 2 | 37 | 37 |
| E F Barrett | New York | 2511 | 10 | 117 | 117 |
| E F Barrett | New York | 2511 | 20 | 69 | 69 |
| E F Barrett | New York | 2511 | U00012 | 9 | 9 |
| E F Barrett | New York | 2511 | U00013 | 9 | 9 |
| E F Barrett | New York | 2511 | U00014 | 13 | 13 |
| E F Barrett | New York | 2511 | U00015 | 13 | 13 |
| E F Barrett | New York | 2511 | U00016 | 16 | 16 |
| E F Barrett | New York | 2511 | U00017 | 16 | 16 |
| E F Barrett | New York | 2511 | U00018 | 16 | 16 |
| E F Barrett | New York | 2511 | U00019 | 16 | 16 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| East River | New York | 2493 | 1 | 12 | 12 |
| East River | New York | 2493 | 2 | 13 | 13 |
| East River | New York | 2493 | 60 | 144 | 144 |
| East River | New York | 2493 | 70 | 67 | 67 |
| Edgewood Energy | New York | 55786 | CT01 | 2 | 2 |
| Edgewood Energy | New York | 55786 | CT02 | 2 | 2 |
| Empire Generating Company LLC | New York | 56259 | CT-1 | 17 | 17 |
| Empire Generating Company LLC | New York | 56259 | CT-2 | 17 | 17 |
| Equus Power I | New York | 56032 | 0001 | 2 | 2 |
| Far Rockaway | New York | 2513 | 40 | 0 | 0 |
| Fortistar North Tonawanda Inc | New York | 54131 | NTCT1 | 4 | 4 |
| Freeport Power Plant No. 2 | New York | 2679 | 5 | 1 | 1 |
| Glenwood | New York | 2514 | 40 | 0 | 0 |
| Glenwood | New York | 2514 | 50 | 0 | 0 |
| Glenwood | New York | 2514 | U00020 | 2 | 2 |
| Glenwood | New York | 2514 | U00021 | 3 | 3 |
| Glenwood Landing Energy Center | New York | 7869 | UGT012 | 2 | 2 |
| Glenwood Landing Energy Center | New York | 7869 | UGT013 | 2 | 2 |
| Harlem River Yard | New York | 7914 | HR01 | 0 | 0 |
| Harlem River Yard | New York | 7914 | HR02 | 0 | 0 |
| Hawkeye Energy Greenport, LLC | New York | 55969 | U-01 | 1 | 1 |
| Hell Gate | New York | 7913 | HG01 | 0 | 0 |
| Hell Gate | New York | 7913 | HG02 | 1 | 1 |
| Hillburn | New York | 2628 | 001 | 0 | 0 |
| Holtsville Facility | New York | 8007 | U00001 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00002 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00003 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00004 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00005 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00006 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00007 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00008 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00009 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00010 | 3 | 3 |
| Holtsville Facility | New York | 8007 | U00011 | 8 | 8 |
| Holtsville Facility | New York | 8007 | U00012 | 8 | 8 |
| Holtsville Facility | New York | 8007 | U00013 | 5 | 5 |
| Holtsville Facility | New York | 8007 | U00014 | 4 | 4 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Holtsville Facility | New York | 8007 | U00015 | 6 | 6 |
| Holtsville Facility | New York | 8007 | U00016 | 6 | 6 |
| Holtsville Facility | New York | 8007 | U00017 | 7 | 7 |
| Holtsville Facility | New York | 8007 | U00018 | 7 | 7 |
| Holtsville Facility | New York | 8007 | U00019 | 6 | 6 |
| Holtsville Facility | New York | 8007 | U00020 | 5 | 5 |
| Huntley Power | New York | 2549 | 67 | 88 | 88 |
| Huntley Power | New York | 2549 | 68 | 68 | 68 |
| Indeck-Corinth Energy Center | New York | 50458 | 1 | 26 | 26 |
| Indeck-Olean Energy Center | New York | 54076 | 1 | 15 | 15 |
| Indeck-Oswego Energy Center | New York | 50450 | 1 | 9 | 9 |
| Indeck-Silver Springs Energy Center | New York | 50449 | 1 | 15 | 15 |
| Indeck-Yerkes Energy Center | New York | 50451 | 1 | 16 | 16 |
| Independence | New York | 54547 | 1 | 19 | 19 |
| Independence | New York | 54547 | 2 | 19 | 19 |
| Independence | New York | 54547 | 3 | 20 | 20 |
| Independence | New York | 54547 | 4 | 20 | 20 |
| KIAC Cogeneration | New York | 54114 | GT1 | 11 | 11 |
| KIAC Cogeneration | New York | 54114 | GT2 | 11 | 11 |
| Lockport | New York | 54041 | 011854 | 15 | 15 |
| Lockport | New York | 54041 | 011855 | 38 | 38 |
| Lockport | New York | 54041 | 011856 | 8 | 8 |
| Massena Energy Facility | New York | 54592 | 001 | 1 | 1 |
| Nassau Energy Corporation | New York | 52056 | 00004 | 76 | 76 |
| Niagara Generation, LLC | New York | 50202 | 1 | 6 | 6 |
| Nissequogue Cogen | New York | 54149 | 1 | 35 | 35 |
| North 1st | New York | 7915 | NO1 | 1 | 1 |
| Northport | New York | 2516 | 1 | 55 | 55 |
| Northport | New York | 2516 | 2 | 78 | 78 |
| Northport | New York | 2516 | 3 | 86 | 86 |
| Northport | New York | 2516 | 4 | 115 | 115 |
| NRG Dunkirk Power | New York | 2554 | 1 | 9 | 9 |
| NRG Dunkirk Power | New York | 2554 | 2 | 83 | 83 |
| NRG Dunkirk Power | New York | 2554 | 3 | 0 | 0 |
| NRG Dunkirk Power | New York | 2554 | 4 | 0 | 0 |
| Oswego Harbor Power | New York | 2594 | 5 | 14 | 14 |
| Oswego Harbor Power | New York | 2594 | 6 | 16 | 16 |
| Pinelawn Power | New York | 56188 | 00001 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Poletti 500 MW CC | New York | 56196 | CTG7A | 11 | 11 |
| Poletti 500 MW CC | New York | 56196 | CTG7B | 10 | 10 |
| Port Jefferson Energy Center | New York | 2517 | 3 | 21 | 21 |
| Port Jefferson Energy Center | New York | 2517 | 4 | 20 | 20 |
| Port Jefferson Energy Center | New York | 2517 | UGT002 | 2 | 2 |
| Port Jefferson Energy Center | New York | 2517 | UGT003 | 1 | 1 |
| Pouch Terminal | New York | 8053 | PT01 | 2 | 2 |
| Project Orange Facility | New York | 54425 | 001 | 0 | 0 |
| Project Orange Facility | New York | 54425 | 002 | 0 | 0 |
| Ravenswood Generating Station | New York | 2500 | 10 | 106 | 106 |
| Ravenswood Generating Station | New York | 2500 | 20 | 116 | 116 |
| Ravenswood Generating Station | New York | 2500 | 30 | 284 | 284 |
| Ravenswood Generating Station | New York | 2500 | CT02-1 | 4 | 4 |
| Ravenswood Generating Station | New York | 2500 | CT02-2 | 4 | 4 |
| Ravenswood Generating Station | New York | 2500 | CT02-3 | 1 | 1 |
| Ravenswood Generating Station | New York | 2500 | CT02-4 | 4 | 4 |
| Ravenswood Generating Station | New York | 2500 | CT03-1 | 3 | 3 |
| Ravenswood Generating Station | New York | 2500 | CT03-2 | 3 | 3 |
| Ravenswood Generating Station | New York | 2500 | CT03-3 | 2 | 2 |
| Ravenswood Generating Station | New York | 2500 | CT03-4 | 3 | 3 |
| Ravenswood Generating Station | New York | 2500 | UCC001 | 13 | 13 |
| Rensselaer Cogen | New York | 54034 | 1GTDBS | 2 | 2 |
| Richard M Flynn (Holtsville) | New York | 7314 | 001 | 38 | 38 |
| S A Carlson | New York | 2682 | 9 | 1 | 1 |
| S A Carlson | New York | 2682 | 10 | 0 | 0 |
| S A Carlson | New York | 2682 | 11 | 0 | 0 |
| S A Carlson | New York | 2682 | 12 | 0 | 0 |
| S A Carlson | New York | 2682 | 20 | 30 | 30 |
| Saranac Power Partners, LP | New York | 54574 | 00001 | 4 | 4 |
| Saranac Power Partners, LP | New York | 54574 | 00002 | 1 | 1 |
| Selkirk Cogen Partners | New York | 10725 | CTG101 | 57 | 57 |
| Selkirk Cogen Partners | New York | 10725 | CTG201 | 17 | 17 |
| Selkirk Cogen Partners | New York | 10725 | CTG301 | 16 | 16 |
| Shoemaker | New York | 2632 | 1 | 1 | 1 |
| Shoreham Energy | New York | 55787 | CT01 | 0 | 0 |
| Shoreham Energy | New York | 55787 | CT02 | 0 | 0 |
| Sterling Power Plant | New York | 50744 | 00001 | 3 | 3 |
| Syracuse Energy Corporation | New York | 50651 | BLR1 | 9 | 9 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Syracuse Energy Corporation | New York | 50651 | BLR2 | 13 | 13 |
| Syracuse Energy Corporation | New York | 50651 | BLR3 | 13 | 13 |
| Syracuse Energy Corporation | New York | 50651 | BLR4 | 4 | 4 |
| Syracuse Energy Corporation | New York | 50651 | BLR5 | 7 | 7 |
| Vernon Boulevard | New York | 7909 | VB01 | 1 | 1 |
| Vernon Boulevard | New York | 7909 | VB02 | 1 | 1 |
| Wading River Facility | New York | 7146 | UGT007 | 4 | 4 |
| Wading River Facility | New York | 7146 | UGT008 | 7 | 7 |
| Wading River Facility | New York | 7146 | UGT009 | 4 | 4 |
| Wading River Facility | New York | 7146 | UGT013 | 4 | 4 |
| West Babylon Facility | New York | 2521 | UGT001 | 3 | 3 |
| WPS Beaver Falls Generation, LLC | New York | 10617 | 1 | 0 | 0 |
| WPS Syracuse Generation, LLC | New York | 10621 | 1 | 2 | 2 |
| NYSERDA | New York | | | 516 | 516 |
| AMP-Ohio Gas Turbines Bowling Green | Ohio | 55262 | CT1 | 0 | 0 |
| AMP-Ohio Gas Turbines Galion | Ohio | 55263 | CT1 | 0 | 0 |
| AMP-Ohio Gas Turbines Napoleon | Ohio | 55264 | CT1 | 0 | 0 |
| Ashtabula | Ohio | 2835 | 7 | 123 | 123 |
| Avon Lake Power Plant | Ohio | 2836 | 10 | 17 | 17 |
| Avon Lake Power Plant | Ohio | 2836 | 12 | 446 | 446 |
| Avon Lake Power Plant | Ohio | 2836 | CT10 | 0 | 0 |
| Bay Shore | Ohio | 2878 | 1 | 242 | 242 |
| Bay Shore | Ohio | 2878 | 2 | 63 | 63 |
| Bay Shore | Ohio | 2878 | 3 | 96 | 96 |
| Bay Shore | Ohio | 2878 | 4 | 130 | 130 |
| Cardinal | Ohio | 2828 | 1 | 504 | 504 |
| Cardinal | Ohio | 2828 | 2 | 530 | 530 |
| Cardinal | Ohio | 2828 | 3 | 627 | 627 |
| Conesville | Ohio | 2840 | 3 | 40 | 40 |
| Conesville | Ohio | 2840 | 4 | 574 | 574 |
| Conesville | Ohio | 2840 | 5 | 385 | 385 |
| Conesville | Ohio | 2840 | 6 | 385 | 385 |
| Darby Electric Generating Station | Ohio | 55247 | CT1 | 5 | 5 |
| Darby Electric Generating Station | Ohio | 55247 | CT2 | 5 | 5 |
| Darby Electric Generating Station | Ohio | 55247 | CT3 | 5 | 5 |
| Darby Electric Generating Station | Ohio | 55247 | CT4 | 4 | 4 |
| Darby Electric Generating Station | Ohio | 55247 | CT5 | 4 | 4 |
| Darby Electric Generating Station | Ohio | 55247 | CT6 | 4 | 4 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Dicks Creek Station | Ohio | 2831 | 1 | 0 | 0 |
| Dresden Energy Facility | Ohio | 55350 | 1A | 38 | 38 |
| Dresden Energy Facility | Ohio | 55350 | 1B | 31 | 31 |
| Duke Energy Hanging Rock, II LLC | Ohio | 55736 | CTG1 | 38 | 38 |
| Duke Energy Hanging Rock, II LLC | Ohio | 55736 | CTG2 | 38 | 38 |
| Duke Energy Hanging Rock, II LLC | Ohio | 55736 | CTG3 | 43 | 43 |
| Duke Energy Hanging Rock, II LLC | Ohio | 55736 | CTG4 | 45 | 45 |
| Duke Energy Washington, II LLC | Ohio | 55397 | CT1 | 39 | 39 |
| Duke Energy Washington, II LLC | Ohio | 55397 | CT2 | 37 | 37 |
| Eastlake | Ohio | 2837 | 1 | 77 | 77 |
| Eastlake | Ohio | 2837 | 2 | 62 | 62 |
| Eastlake | Ohio | 2837 | 3 | 73 | 73 |
| Eastlake | Ohio | 2837 | 4 | 179 | 179 |
| Eastlake | Ohio | 2837 | 5 | 562 | 562 |
| Eastlake | Ohio | 2837 | 6 | 1 | 1 |
| Frank M Tait Station | Ohio | 2847 | 1 | 4 | 4 |
| Frank M Tait Station | Ohio | 2847 | 2 | 4 | 4 |
| Frank M Tait Station | Ohio | 2847 | 3 | 6 | 6 |
| Fremont Energy Center | Ohio | 55701 | CT01 | 29 | 29 |
| Fremont Energy Center | Ohio | 55701 | CT02 | 30 | 30 |
| Gen J M Gavin | Ohio | 8102 | 1 | 1,517 | 1,517 |
| Gen J M Gavin | Ohio | 8102 | 2 | 1,323 | 1,323 |
| Greenville Electric Gen Station | Ohio | 55228 | G1CT1 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G1CT2 | 3 | 3 |
| Greenville Electric Gen Station | Ohio | 55228 | G2CT1 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G2CT2 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G3CT1 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G3CT2 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G4CT1 | 2 | 2 |
| Greenville Electric Gen Station | Ohio | 55228 | G4CT2 | 2 | 2 |
| Hamilton Municipal Power Plant | Ohio | 2917 | 9 | 31 | 31 |
| J M Stuart | Ohio | 2850 | 1 | 585 | 585 |
| J M Stuart | Ohio | 2850 | 2 | 533 | 533 |
| J M Stuart | Ohio | 2850 | 3 | 559 | 559 |
| J M Stuart | Ohio | 2850 | 4 | 634 | 634 |
| Killen Station | Ohio | 6031 | 2 | 719 | 719 |
| Kyger Creek | Ohio | 2876 | 1 | 213 | 213 |
| Kyger Creek | Ohio | 2876 | 2 | 199 | 199 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Kyger Creek | Ohio | 2876 | 3 | 185 | 185 |
| Kyger Creek | Ohio | 2876 | 4 | 194 | 194 |
| Kyger Creek | Ohio | 2876 | 5 | 197 | 197 |
| Lake Shore | Ohio | 2838 | 18 | 62 | 62 |
| Mad River | Ohio | 2860 | A | | |
| Mad River | Ohio | 2860 | B | | |
| Madison Generating Station | Ohio | 55110 | 1 | 5 | 5 |
| Madison Generating Station | Ohio | 55110 | 2 | 5 | 5 |
| Madison Generating Station | Ohio | 55110 | 3 | 4 | 4 |
| Madison Generating Station | Ohio | 55110 | 4 | 4 | 4 |
| Madison Generating Station | Ohio | 55110 | 5 | 4 | 4 |
| Madison Generating Station | Ohio | 55110 | 6 | 6 | 6 |
| Madison Generating Station | Ohio | 55110 | 7 | 6 | 6 |
| Madison Generating Station | Ohio | 55110 | 8 | 5 | 5 |
| Miami Fort Generating Station | Ohio | 2832 | 6 | 169 | 169 |
| Miami Fort Generating Station | Ohio | 2832 | 7 | 616 | 616 |
| Miami Fort Generating Station | Ohio | 2832 | 8 | 557 | 557 |
| Middletown Coke Company, LLC | Ohio | 57822 | YNKE | 115 | 115 |
| Muskingum River | Ohio | 2872 | 1 | 63 | 63 |
| Muskingum River | Ohio | 2872 | 2 | 71 | 71 |
| Muskingum River | Ohio | 2872 | 3 | 97 | 97 |
| Muskingum River | Ohio | 2872 | 4 | 94 | 94 |
| Muskingum River | Ohio | 2872 | 5 | 433 | 433 |
| Niles | Ohio | 2861 | 1 | 39 | 39 |
| Niles | Ohio | 2861 | 2 | 1 | 1 |
| Niles | Ohio | 2861 | CTA | 0 | 0 |
| O H Hutchings | Ohio | 2848 | H-1 | 2 | 2 |
| O H Hutchings | Ohio | 2848 | H-2 | 3 | 3 |
| O H Hutchings | Ohio | 2848 | H-3 | 8 | 8 |
| O H Hutchings | Ohio | 2848 | H-4 | | |
| O H Hutchings | Ohio | 2848 | H-5 | 9 | 9 |
| O H Hutchings | Ohio | 2848 | H-6 | 8 | 8 |
| O H Hutchings | Ohio | 2848 | H-7 | 0 | 0 |
| Omega JV2 Bowling Green | Ohio | 7783 | P001 | 1 | 1 |
| Omega JV2 Hamilton | Ohio | 7782 | P001 | 1 | 1 |
| Picway | Ohio | 2843 | 9 | 20 | 20 |
| R E Burger | Ohio | 2864 | 5 | | |
| R E Burger | Ohio | 2864 | 6 | | |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| R E Burger | Ohio | 2864 | 7 | | |
| R E Burger | Ohio | 2864 | 8 | | |
| Richard Gorsuch | Ohio | 7253 | 1 | | |
| Richard Gorsuch | Ohio | 7253 | 2 | | |
| Richard Gorsuch | Ohio | 7253 | 3 | | |
| Richard Gorsuch | Ohio | 7253 | 4 | | |
| Richland Peaking Station | Ohio | 2880 | CTG4 | 16 | 16 |
| Richland Peaking Station | Ohio | 2880 | CTG5 | 17 | 17 |
| Richland Peaking Station | Ohio | 2880 | CTG6 | 15 | 15 |
| Robert P Mone | Ohio | 7872 | 1 | 8 | 8 |
| Robert P Mone | Ohio | 7872 | 2 | 8 | 8 |
| Robert P Mone | Ohio | 7872 | 3 | 7 | 7 |
| Rolling Hills Generating LLC | Ohio | 55401 | CT-1 | 6 | 6 |
| Rolling Hills Generating LLC | Ohio | 55401 | CT-2 | 4 | 4 |
| Rolling Hills Generating LLC | Ohio | 55401 | CT-3 | 13 | 13 |
| Rolling Hills Generating LLC | Ohio | 55401 | CT-4 | 6 | 6 |
| Rolling Hills Generating LLC | Ohio | 55401 | CT-5 | 7 | 7 |
| Tait Electric Generating Station | Ohio | 55248 | CT4 | 7 | 7 |
| Tait Electric Generating Station | Ohio | 55248 | CT5 | 7 | 7 |
| Tait Electric Generating Station | Ohio | 55248 | CT6 | 6 | 6 |
| Tait Electric Generating Station | Ohio | 55248 | CT7 | 7 | 7 |
| Troy Energy, LLC | Ohio | 55348 | 1 | 11 | 11 |
| Troy Energy, LLC | Ohio | 55348 | 2 | 13 | 13 |
| Troy Energy, LLC | Ohio | 55348 | 3 | 13 | 13 |
| Troy Energy, LLC | Ohio | 55348 | 4 | 14 | 14 |
| W H Sammis | Ohio | 2866 | 1 | 144 | 144 |
| W H Sammis | Ohio | 2866 | 2 | 132 | 132 |
| W H Sammis | Ohio | 2866 | 3 | 157 | 157 |
| W H Sammis | Ohio | 2866 | 4 | 152 | 152 |
| W H Sammis | Ohio | 2866 | 5 | 224 | 224 |
| W H Sammis | Ohio | 2866 | 6 | 623 | 623 |
| W H Sammis | Ohio | 2866 | 7 | 576 | 576 |
| W H Zimmer Generating Station | Ohio | 6019 | 1 | 1,325 | 1,325 |
| Walter C Beckjord Generating Station | Ohio | 2830 | 1 | | |
| Walter C Beckjord Generating Station | Ohio | 2830 | 2 | | |
| Walter C Beckjord Generating Station | Ohio | 2830 | 3 | 86 | 86 |
| Walter C Beckjord Generating Station | Ohio | 2830 | 4 | 85 | 85 |
| Walter C Beckjord Generating Station | Ohio | 2830 | 5 | 142 | 142 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Walter C Beckjord Generating Station | Ohio | 2830 | 6 | 315 | 315 |
| Walter C Beckjord Generating Station | Ohio | 2830 | CT1 | 0 | 0 |
| Walter C Beckjord Generating Station | Ohio | 2830 | CT2 | 0 | 0 |
| Walter C Beckjord Generating Station | Ohio | 2830 | CT3 | 0 | 0 |
| Walter C Beckjord Generating Station | Ohio | 2830 | CT4 | 0 | 0 |
| Waterford Plant | Ohio | 55503 | 1 | 28 | 28 |
| Waterford Plant | Ohio | 55503 | 2 | 29 | 29 |
| Waterford Plant | Ohio | 55503 | 3 | 33 | 33 |
| West Lorain | Ohio | 2869 | 2 | 5 | 5 |
| West Lorain | Ohio | 2869 | 3 | 4 | 4 |
| West Lorain | Ohio | 2869 | 4 | 5 | 5 |
| West Lorain | Ohio | 2869 | 5 | 6 | 6 |
| West Lorain | Ohio | 2869 | 6 | 4 | 4 |
| West Lorain | Ohio | 2869 | 1A | 1 | 1 |
| West Lorain | Ohio | 2869 | 1B | 1 | 1 |
| Woodsdale | Ohio | 7158 | **GT1 | 3 | 3 |
| Woodsdale | Ohio | 7158 | **GT2 | 4 | 4 |
| Woodsdale | Ohio | 7158 | **GT3 | 4 | 4 |
| Woodsdale | Ohio | 7158 | **GT4 | 3 | 3 |
| Woodsdale | Ohio | 7158 | **GT5 | 3 | 3 |
| Woodsdale | Ohio | 7158 | **GT6 | 3 | 3 |
| AES Shady Point | Oklahoma | 10671 | 1A | 128 | 128 |
| AES Shady Point | Oklahoma | 10671 | 1B | 130 | 130 |
| AES Shady Point | Oklahoma | 10671 | 2A | 125 | 125 |
| AES Shady Point | Oklahoma | 10671 | 2B | 124 | 124 |
| Anadarko | Oklahoma | 3006 | 3 | 4 | 4 |
| Anadarko | Oklahoma | 3006 | 7 | 4 | 4 |
| Anadarko | Oklahoma | 3006 | 8 | 6 | 6 |
| Anadarko | Oklahoma | 3006 | 9 | 9 | 9 |
| Anadarko | Oklahoma | 3006 | 10 | 10 | 10 |
| Anadarko | Oklahoma | 3006 | 11 | 9 | 9 |
| Anadarko Plant | Oklahoma | 3006 | 4 | 9 | 9 |
| Anadarko Plant | Oklahoma | 3006 | 5 | 14 | 14 |
| Anadarko Plant | Oklahoma | 3006 | 6 | 17 | 17 |
| Chouteau Power Plant | Oklahoma | 7757 | 1 | 30 | 30 |
| Chouteau Power Plant | Oklahoma | 7757 | 2 | 36 | 36 |
| Chouteau Power Plant | Oklahoma | 7757 | 3 | 9 | 9 |
| Chouteau Power Plant | Oklahoma | 7757 | 4 | 10 | 10 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Comanche (8059) | Oklahoma | 8059 | 7251 | 108 | 108 |
| Comanche (8059) | Oklahoma | 8059 | 7252 | 77 | 77 |
| Grand River Dam Authority | Oklahoma | 165 | 1 | 629 | 629 |
| Grand River Dam Authority | Oklahoma | 165 | 2 | 701 | 701 |
| Green Country Energy, LLC | Oklahoma | 55146 | CTGEN1 | 62 | 62 |
| Green Country Energy, LLC | Oklahoma | 55146 | CTGEN2 | 66 | 66 |
| Green Country Energy, LLC | Oklahoma | 55146 | CTGEN3 | 60 | 60 |
| Horseshoe Lake | Oklahoma | 2951 | 6 | 100 | 100 |
| Horseshoe Lake | Oklahoma | 2951 | 7 | 160 | 160 |
| Horseshoe Lake | Oklahoma | 2951 | 8 | 187 | 187 |
| Horseshoe Lake | Oklahoma | 2951 | 9 | 12 | 12 |
| Horseshoe Lake | Oklahoma | 2951 | 10 | 11 | 11 |
| Hugo | Oklahoma | 6772 | 1 | 627 | 627 |
| McClain Energy Facility | Oklahoma | 55457 | CT1 | 81 | 81 |
| McClain Energy Facility | Oklahoma | 55457 | CT2 | 79 | 79 |
| Mooreland | Oklahoma | 3008 | 1 | 4 | 4 |
| Mooreland | Oklahoma | 3008 | 2 | 62 | 62 |
| Mooreland | Oklahoma | 3008 | 3 | 47 | 47 |
| Muskogee | Oklahoma | 2952 | 3 | | |
| Muskogee | Oklahoma | 2952 | 4 | 605 | 605 |
| Muskogee | Oklahoma | 2952 | 5 | 622 | 622 |
| Muskogee | Oklahoma | 2952 | 6 | 624 | 624 |
| Mustang | Oklahoma | 2953 | 1 | 10 | 10 |
| Mustang | Oklahoma | 2953 | 2 | 12 | 12 |
| Mustang | Oklahoma | 2953 | 3 | 70 | 70 |
| Mustang | Oklahoma | 2953 | 4 | 149 | 149 |
| Mustang | Oklahoma | 2953 | 5A-1 | 0 | 0 |
| Mustang | Oklahoma | 2953 | 5A-2 | 0 | 0 |
| Mustang | Oklahoma | 2953 | 5B-1 | 0 | 0 |
| Mustang | Oklahoma | 2953 | 5B-2 | 0 | 0 |
| Northeastern | Oklahoma | 2963 | 3302 | 269 | 269 |
| Northeastern | Oklahoma | 2963 | 3313 | 687 | 687 |
| Northeastern | Oklahoma | 2963 | 3314 | 657 | 657 |
| Northeastern | Oklahoma | 2963 | 3301A | 88 | 88 |
| Northeastern | Oklahoma | 2963 | 3301B | 85 | 85 |
| Oklahoma Cogeneration LLC | Oklahoma | 50558 | CC01 | 12 | 12 |
| Oneta Energy Center | Oklahoma | 55225 | CTG-1 | 82 | 82 |
| Oneta Energy Center | Oklahoma | 55225 | CTG-2 | 80 | 80 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Oneta Energy Center | Oklahoma | 55225 | CTG-3 | 74 | 74 |
| Oneta Energy Center | Oklahoma | 55225 | CTG-4 | 83 | 83 |
| Ponca | Oklahoma | 762 | 2 | 0 | 0 |
| Ponca | Oklahoma | 762 | 3 | 14 | 14 |
| Ponca | Oklahoma | 762 | 4 | 5 | 5 |
| Redbud Power Plant | Oklahoma | 55463 | CT-01 | 39 | 39 |
| Redbud Power Plant | Oklahoma | 55463 | CT-02 | 37 | 37 |
| Redbud Power Plant | Oklahoma | 55463 | CT-03 | 40 | 40 |
| Redbud Power Plant | Oklahoma | 55463 | CT-04 | 37 | 37 |
| Riverside (4940) | Oklahoma | 4940 | 1501 | 188 | 188 |
| Riverside (4940) | Oklahoma | 4940 | 1502 | 250 | 250 |
| Riverside (4940) | Oklahoma | 4940 | 1503 | 10 | 10 |
| Riverside (4940) | Oklahoma | 4940 | 1504 | 9 | 9 |
| Seminole (2956) | Oklahoma | 2956 | 1 | 278 | 278 |
| Seminole (2956) | Oklahoma | 2956 | 2 | 284 | 284 |
| Seminole (2956) | Oklahoma | 2956 | 3 | 301 | 301 |
| Sooner | Oklahoma | 6095 | 1 | 627 | 627 |
| Sooner | Oklahoma | 6095 | 2 | 625 | 625 |
| Southwestern | Oklahoma | 2964 | 8002 | 17 | 17 |
| Southwestern | Oklahoma | 2964 | 8003 | 151 | 151 |
| Southwestern | Oklahoma | 2964 | 8004 | 11 | 11 |
| Southwestern | Oklahoma | 2964 | 8005 | 11 | 11 |
| Southwestern | Oklahoma | 2964 | 801N | 11 | 11 |
| Southwestern | Oklahoma | 2964 | 801S | 12 | 12 |
| Spring Creek Power Plant | Oklahoma | 55651 | CT-01 | 5 | 5 |
| Spring Creek Power Plant | Oklahoma | 55651 | CT-02 | 11 | 11 |
| Spring Creek Power Plant | Oklahoma | 55651 | CT-03 | 9 | 9 |
| Spring Creek Power Plant | Oklahoma | 55651 | CT-04 | 9 | 9 |
| Tenaska Kiamichi Generating Station | Oklahoma | 55501 | CTGDB1 | 92 | 92 |
| Tenaska Kiamichi Generating Station | Oklahoma | 55501 | CTGDB2 | 100 | 100 |
| Tenaska Kiamichi Generating Station | Oklahoma | 55501 | CTGDB3 | 84 | 84 |
| Tenaska Kiamichi Generating Station | Oklahoma | 55501 | CTGDB4 | 88 | 88 |
| Tulsa | Oklahoma | 2965 | 1402 | 42 | 42 |
| Tulsa | Oklahoma | 2965 | 1403 | 12 | 12 |
| Tulsa | Oklahoma | 2965 | 1404 | 41 | 41 |
| Weleetka | Oklahoma | 2966 | 4 | 2 | 2 |
| Weleetka | Oklahoma | 2966 | 5 | | |
| Weleetka | Oklahoma | 2966 | 6 | 0 | 0 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| AES Beaver Valley LLC | Pennsylvania | 10676 | 032 | 39 | 39 |
| AES Beaver Valley LLC | Pennsylvania | 10676 | 033 | 37 | 37 |
| AES Beaver Valley LLC | Pennsylvania | 10676 | 034 | 38 | 38 |
| AES Beaver Valley LLC | Pennsylvania | 10676 | 035 | 18 | 18 |
| AES Ironwood | Pennsylvania | 55337 | 0001 | 67 | 67 |
| AES Ironwood | Pennsylvania | 55337 | 0002 | 66 | 66 |
| Allegheny Energy Units 1 & 2 | Pennsylvania | 55196 | 1 | 6 | 6 |
| Allegheny Energy Units 1 & 2 | Pennsylvania | 55196 | 2 | 6 | 6 |
| Allegheny Energy Units 3, 4 & 5 | Pennsylvania | 55710 | 3 | 24 | 24 |
| Allegheny Energy Units 3, 4 & 5 | Pennsylvania | 55710 | 4 | 25 | 25 |
| Allegheny Energy Units 8 & 9 | Pennsylvania | 55377 | 8 | 5 | 5 |
| Allegheny Energy Units 8 & 9 | Pennsylvania | 55377 | 9 | 5 | 5 |
| Armstrong Energy Ltd Partnership, LLLP | Pennsylvania | 55347 | 1 | 29 | 29 |
| Armstrong Energy Ltd Partnership, LLLP | Pennsylvania | 55347 | 2 | 28 | 28 |
| Armstrong Energy Ltd Partnership, LLLP | Pennsylvania | 55347 | 3 | 27 | 27 |
| Armstrong Energy Ltd Partnership, LLLP | Pennsylvania | 55347 | 4 | 27 | 27 |
| Armstrong Power Station | Pennsylvania | 3178 | 1 | 106 | 106 |
| Armstrong Power Station | Pennsylvania | 3178 | 2 | 66 | 66 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 1 | 11 | 11 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 2 | 14 | 14 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 3 | 11 | 11 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 5 | 10 | 10 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 6 | 10 | 10 |
| Bethlehem Power Plant | Pennsylvania | 55690 | 7 | 9 | 9 |
| Bruce Mansfield | Pennsylvania | 6094 | 1 | 896 | 896 |
| Bruce Mansfield | Pennsylvania | 6094 | 2 | 862 | 862 |
| Bruce Mansfield | Pennsylvania | 6094 | 3 | 939 | 939 |
| Brunner Island | Pennsylvania | 3140 | 1 | 239 | 239 |
| Brunner Island | Pennsylvania | 3140 | 2 | 310 | 310 |
| Brunner Island | Pennsylvania | 3140 | 3 | 552 | 552 |
| Brunot Island Power Station | Pennsylvania | 3096 | 3 | 5 | 5 |
| Brunot Island Power Station | Pennsylvania | 3096 | 2A | 3 | 3 |
| Brunot Island Power Station | Pennsylvania | 3096 | 2B | 4 | 4 |
| Cambria Cogen | Pennsylvania | 10641 | 1 | 72 | 72 |
| Cambria Cogen | Pennsylvania | 10641 | 2 | 76 | 76 |
| Chambersburg Units 12 & 13 | Pennsylvania | 55654 | 12 | 8 | 8 |
| Chambersburg Units 12 & 13 | Pennsylvania | 55654 | 13 | 8 | 8 |
| Cheswick | Pennsylvania | 8226 | 1 | 446 | 446 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Colver Power Project | Pennsylvania | 10143 | AAB01 | 163 | 163 |
| Conemaugh | Pennsylvania | 3118 | 1 | 859 | 859 |
| Conemaugh | Pennsylvania | 3118 | 2 | 878 | 878 |
| Cromby | Pennsylvania | 3159 | 1 | 5 | 5 |
| Cromby | Pennsylvania | 3159 | 2 | 15 | 15 |
| Croydon Generating Station | Pennsylvania | 8012 | 11 | 1 | 1 |
| Croydon Generating Station | Pennsylvania | 8012 | 12 | 1 | 1 |
| Croydon Generating Station | Pennsylvania | 8012 | 21 | 0 | 0 |
| Croydon Generating Station | Pennsylvania | 8012 | 22 | 0 | 0 |
| Croydon Generating Station | Pennsylvania | 8012 | 31 | 0 | 0 |
| Croydon Generating Station | Pennsylvania | 8012 | 32 | 0 | 0 |
| Croydon Generating Station | Pennsylvania | 8012 | 41 | 0 | 0 |
| Croydon Generating Station | Pennsylvania | 8012 | 42 | 1 | 1 |
| Duke Energy Fayette, II LLC | Pennsylvania | 55516 | CTG1 | 28 | 28 |
| Duke Energy Fayette, II LLC | Pennsylvania | 55516 | CTG2 | 27 | 27 |
| Ebensburg Power Company | Pennsylvania | 10603 | 031 | 94 | 94 |
| Eddystone Generating Station | Pennsylvania | 3161 | 1 | | |
| Eddystone Generating Station | Pennsylvania | 3161 | 2 | | |
| Eddystone Generating Station | Pennsylvania | 3161 | 3 | 28 | 28 |
| Eddystone Generating Station | Pennsylvania | 3161 | 4 | 30 | 30 |
| Elrama | Pennsylvania | 3098 | 1 | 4 | 4 |
| Elrama | Pennsylvania | 3098 | 2 | 7 | 7 |
| Elrama | Pennsylvania | 3098 | 3 | 6 | 6 |
| Elrama | Pennsylvania | 3098 | 4 | 25 | 25 |
| Fairless Energy, LLC | Pennsylvania | 55298 | 1A | 27 | 27 |
| Fairless Energy, LLC | Pennsylvania | 55298 | 1B | 27 | 27 |
| Fairless Energy, LLC | Pennsylvania | 55298 | 2A | 26 | 26 |
| Fairless Energy, LLC | Pennsylvania | 55298 | 2B | 25 | 25 |
| Fairless Hills Generating Station | Pennsylvania | 7701 | PHBLR4 | 30 | 30 |
| Fairless Hills Generating Station | Pennsylvania | 7701 | PHBLR5 | 23 | 23 |
| FPL Energy Marcus Hook, LP | Pennsylvania | 55801 | 0001 | 37 | 37 |
| FPL Energy Marcus Hook, LP | Pennsylvania | 55801 | 0002 | 37 | 37 |
| FPL Energy Marcus Hook, LP | Pennsylvania | 55801 | 0003 | 39 | 39 |
| G F Weaton | Pennsylvania | 50130 | 34 | 61 | 61 |
| G F Weaton | Pennsylvania | 50130 | 35 | 63 | 63 |
| Gilberton Power Company | Pennsylvania | 10113 | 031 | 52 | 52 |
| Gilberton Power Company | Pennsylvania | 10113 | 032 | 50 | 50 |
| Grays Ferry Cogen Partnership | Pennsylvania | 54785 | 2 | 158 | 158 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Grays Ferry Cogen Partnership | Pennsylvania | 54785 | 25 | 20 | 20 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-1A | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-1B | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-2A | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-2B | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-3A | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-3B | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-4A | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-4B | 4 | 4 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-5A | 3 | 3 |
| Handsome Lake Energy | Pennsylvania | 55233 | EU-5B | 3 | 3 |
| Hatfield's Ferry Power Station | Pennsylvania | 3179 | 1 | 558 | 558 |
| Hatfield's Ferry Power Station | Pennsylvania | 3179 | 2 | 540 | 540 |
| Hatfield's Ferry Power Station | Pennsylvania | 3179 | 3 | 500 | 500 |
| Hazleton Generation | Pennsylvania | 10870 | TURB2 | 0 | 0 |
| Hazleton Generation | Pennsylvania | 10870 | TURB3 | 0 | 0 |
| Hazleton Generation | Pennsylvania | 10870 | TURB4 | 0 | 0 |
| Hazleton Generation | Pennsylvania | 10870 | TURBIN | 1 | 1 |
| Homer City | Pennsylvania | 3122 | 1 | 556 | 556 |
| Homer City | Pennsylvania | 3122 | 2 | 500 | 500 |
| Homer City | Pennsylvania | 3122 | 3 | 622 | 622 |
| Hunlock Creek Energy Center | Pennsylvania | 3176 | 6 | | |
| Hunlock Creek Energy Center | Pennsylvania | 3176 | CT5 | 7 | 7 |
| Hunlock Creek Energy Center | Pennsylvania | 3176 | CT6 | 20 | 20 |
| Hunlock Unit 4 | Pennsylvania | 56397 | 4 | 1 | 1 |
| Hunterstown Combined Cycle | Pennsylvania | 55976 | CT101 | 21 | 21 |
| Hunterstown Combined Cycle | Pennsylvania | 55976 | CT201 | 27 | 27 |
| Hunterstown Combined Cycle | Pennsylvania | 55976 | CT301 | 23 | 23 |
| Keystone | Pennsylvania | 3136 | 1 | 876 | 876 |
| Keystone | Pennsylvania | 3136 | 2 | 919 | 919 |
| Liberty Electric Power Plant | Pennsylvania | 55231 | 0001 | 39 | 39 |
| Liberty Electric Power Plant | Pennsylvania | 55231 | 0002 | 41 | 41 |
| Lower Mount Bethel Energy | Pennsylvania | 55667 | CT01 | 34 | 34 |
| Lower Mount Bethel Energy | Pennsylvania | 55667 | CT02 | 35 | 35 |
| Martins Creek | Pennsylvania | 3148 | 3 | 293 | 293 |
| Martins Creek | Pennsylvania | 3148 | 4 | 275 | 275 |
| Mitchell Power Station | Pennsylvania | 3181 | 1 | 0 | 0 |
| Mitchell Power Station | Pennsylvania | 3181 | 2 | | |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Mitchell Power Station | Pennsylvania | 3181 | 3 | 0 | 0 |
| Mitchell Power Station | Pennsylvania | 3181 | 33 | 210 | 210 |
| Montour | Pennsylvania | 3149 | 1 | 621 | 621 |
| Montour | Pennsylvania | 3149 | 2 | 621 | 621 |
| Mountain | Pennsylvania | 3111 | 031 | 1 | 1 |
| Mountain | Pennsylvania | 3111 | 032 | 1 | 1 |
| Mt. Carmel Cogeneration | Pennsylvania | 10343 | SG-101 | 71 | 71 |
| New Castle | Pennsylvania | 3138 | 3 | 31 | 31 |
| New Castle | Pennsylvania | 3138 | 4 | 35 | 35 |
| New Castle | Pennsylvania | 3138 | 5 | 51 | 51 |
| North East Cogeneration Plant | Pennsylvania | 54571 | 001 | | |
| North East Cogeneration Plant | Pennsylvania | 54571 | 002 | | |
| Northampton Generating Plant | Pennsylvania | 50888 | NGC01 | 151 | 151 |
| Northeastern Power Company | Pennsylvania | 50039 | 031 | 52 | 52 |
| Ontelaunee Energy Center | Pennsylvania | 55193 | CT1 | 20 | 20 |
| Ontelaunee Energy Center | Pennsylvania | 55193 | CT2 | 21 | 21 |
| Panther Creek Energy Facility | Pennsylvania | 50776 | 1 | 65 | 65 |
| Panther Creek Energy Facility | Pennsylvania | 50776 | 2 | 63 | 63 |
| PEI Power Corporation | Pennsylvania | 50279 | 2 | 8 | 8 |
| Piney Creek Power Plant | Pennsylvania | 54144 | 031 | 54 | 54 |
| Portland | Pennsylvania | 3113 | 1 | 43 | 43 |
| Portland | Pennsylvania | 3113 | 2 | 62 | 62 |
| Portland | Pennsylvania | 3113 | 5 | 1 | 1 |
| Richmond | Pennsylvania | 3168 | 91 | 0 | 0 |
| Richmond | Pennsylvania | 3168 | 92 | 0 | 0 |
| Schuylkill | Pennsylvania | 3169 | 1 | 3 | 3 |
| Scrubgrass Generating Plant | Pennsylvania | 50974 | 1 | 68 | 68 |
| Scrubgrass Generating Plant | Pennsylvania | 50974 | 2 | 69 | 69 |
| Seward | Pennsylvania | 3130 | 1 | 233 | 233 |
| Seward | Pennsylvania | 3130 | 2 | 227 | 227 |
| Shawville | Pennsylvania | 3131 | 1 | 56 | 56 |
| Shawville | Pennsylvania | 3131 | 2 | 64 | 64 |
| Shawville | Pennsylvania | 3131 | 3 | 95 | 95 |
| Shawville | Pennsylvania | 3131 | 4 | 79 | 79 |
| St. Nicholas Cogeneration Project | Pennsylvania | 54634 | 1 | 120 | 120 |
| Sunbury | Pennsylvania | 3152 | 3 | 32 | 32 |
| Sunbury | Pennsylvania | 3152 | 4 | 32 | 32 |
| Sunbury | Pennsylvania | 3152 | 1A | 11 | 11 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Sunbury | Pennsylvania | 3152 | 1B | 11 | 11 |
| Sunbury | Pennsylvania | 3152 | 2A | 12 | 12 |
| Sunbury | Pennsylvania | 3152 | 2B | 0 | 0 |
| Titus | Pennsylvania | 3115 | 1 | 25 | 25 |
| Titus | Pennsylvania | 3115 | 2 | 17 | 17 |
| Titus | Pennsylvania | 3115 | 3 | 26 | 26 |
| Tolna | Pennsylvania | 3116 | 031 | 0 | 0 |
| Tolna | Pennsylvania | 3116 | 032 | 0 | 0 |
| Warren | Pennsylvania | 3132 | 005 | 12 | 12 |
| Wheelabrator - Frackville | Pennsylvania | 50879 | GEN1 | 77 | 77 |
| WPS Westwood Generation, LLC | Pennsylvania | 50611 | 031 | 54 | 54 |
| York Energy Center | Pennsylvania | 55524 | 1 | 12 | 12 |
| York Energy Center | Pennsylvania | 55524 | 2 | 12 | 12 |
| York Energy Center | Pennsylvania | 55524 | 3 | 12 | 12 |
| Allen | Tennessee | 3393 | 1 | 226 | 226 |
| Allen | Tennessee | 3393 | 2 | 242 | 242 |
| Allen | Tennessee | 3393 | 3 | 246 | 246 |
| Allen | Tennessee | 3393 | ACT17 | 0 | 0 |
| Allen | Tennessee | 3393 | ACT18 | 0 | 0 |
| Allen | Tennessee | 3393 | ACT19 | 0 | 0 |
| Allen | Tennessee | 3393 | ACT20 | 0 | 0 |
| Brownsville CT | Tennessee | 55081 | AA-001 | 22 | 22 |
| Brownsville CT | Tennessee | 55081 | AA-002 | 20 | 20 |
| Brownsville CT | Tennessee | 55081 | AA-003 | 19 | 19 |
| Brownsville CT | Tennessee | 55081 | AA-004 | 19 | 19 |
| Bull Run | Tennessee | 3396 | 1 | 605 | 605 |
| Chemours Johnsonville | Tennessee | 880001 | JVD1 | | |
| Chemours Johnsonville | Tennessee | 880001 | JVD2 | | |
| Chemours Johnsonville | Tennessee | 880001 | JVD3 | | |
| Chemours Johnsonville | Tennessee | 880001 | JVD4 | | |
| Cumberland | Tennessee | 3399 | 1 | 1,301 | 1,301 |
| Cumberland | Tennessee | 3399 | 2 | 1,220 | 1,220 |
| Gallatin | Tennessee | 3403 | 1 | 250 | 250 |
| Gallatin | Tennessee | 3403 | 2 | 247 | 247 |
| Gallatin | Tennessee | 3403 | 3 | 264 | 264 |
| Gallatin | Tennessee | 3403 | 4 | 280 | 280 |
| Gallatin | Tennessee | 3403 | GCT1 | 1 | 1 |
| Gallatin | Tennessee | 3403 | GCT2 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Gallatin | Tennessee | 3403 | GCT3 | 2 | 2 |
| Gallatin | Tennessee | 3403 | GCT4 | 2 | 2 |
| Gallatin | Tennessee | 3403 | GCT5 | 3 | 3 |
| Gallatin | Tennessee | 3403 | GCT6 | 2 | 2 |
| Gallatin | Tennessee | 3403 | GCT7 | 3 | 3 |
| Gallatin | Tennessee | 3403 | GCT8 | 3 | 3 |
| Gleason Generating Facility | Tennessee | 55251 | CTG-1 | 2 | 2 |
| Gleason Generating Facility | Tennessee | 55251 | CTG-2 | 3 | 3 |
| Gleason Generating Facility | Tennessee | 55251 | CTG-3 | 3 | 3 |
| John Sevier | Tennessee | 3405 | 1 | 89 | 89 |
| John Sevier | Tennessee | 3405 | 2 | 112 | 112 |
| John Sevier | Tennessee | 3405 | 3 | 76 | 76 |
| John Sevier | Tennessee | 3405 | 4 | 120 | 120 |
| John Sevier | Tennessee | 3405 | JCC1 | 33 | 33 |
| John Sevier | Tennessee | 3405 | JCC2 | 33 | 33 |
| John Sevier | Tennessee | 3405 | JCC3 | 30 | 30 |
| Johnsonville | Tennessee | 3406 | 1 | 110 | 110 |
| Johnsonville | Tennessee | 3406 | 2 | 115 | 115 |
| Johnsonville | Tennessee | 3406 | 3 | 114 | 114 |
| Johnsonville | Tennessee | 3406 | 4 | 121 | 121 |
| Johnsonville | Tennessee | 3406 | 5 | 75 | 75 |
| Johnsonville | Tennessee | 3406 | 6 | 77 | 77 |
| Johnsonville | Tennessee | 3406 | 7 | 112 | 112 |
| Johnsonville | Tennessee | 3406 | 8 | 65 | 65 |
| Johnsonville | Tennessee | 3406 | 9 | 54 | 54 |
| Johnsonville | Tennessee | 3406 | 10 | 47 | 47 |
| Johnsonville | Tennessee | 3406 | JCT1 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT10 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT11 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT12 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT13 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT14 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT15 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT16 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT17 | 5 | 5 |
| Johnsonville | Tennessee | 3406 | JCT18 | 5 | 5 |
| Johnsonville | Tennessee | 3406 | JCT19 | 4 | 4 |
| Johnsonville | Tennessee | 3406 | JCT2 | 1 | 1 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Johnsonville | Tennessee | 3406 | JCT20 | 5 | 5 |
| Johnsonville | Tennessee | 3406 | JCT3 | 0 | 0 |
| Johnsonville | Tennessee | 3406 | JCT4 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT5 | 1 | 1 |
| Johnsonville | Tennessee | 3406 | JCT6 | 0 | 0 |
| Johnsonville | Tennessee | 3406 | JCT7 | 0 | 0 |
| Johnsonville | Tennessee | 3406 | JCT8 | 0 | 0 |
| Johnsonville | Tennessee | 3406 | JCT9 | 0 | 0 |
| Kingston | Tennessee | 3407 | 1 | 107 | 107 |
| Kingston | Tennessee | 3407 | 2 | 102 | 102 |
| Kingston | Tennessee | 3407 | 3 | 104 | 104 |
| Kingston | Tennessee | 3407 | 4 | 93 | 93 |
| Kingston | Tennessee | 3407 | 5 | 135 | 135 |
| Kingston | Tennessee | 3407 | 6 | 131 | 131 |
| Kingston | Tennessee | 3407 | 7 | 124 | 124 |
| Kingston | Tennessee | 3407 | 8 | 142 | 142 |
| Kingston | Tennessee | 3407 | 9 | 117 | 117 |
| Lagoon Creek | Tennessee | 7845 | LCC1 | 29 | 29 |
| Lagoon Creek | Tennessee | 7845 | LCC2 | 30 | 30 |
| Lagoon Creek | Tennessee | 7845 | LCT1 | 5 | 5 |
| Lagoon Creek | Tennessee | 7845 | LCT10 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT11 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT12 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT2 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT3 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT4 | 5 | 5 |
| Lagoon Creek | Tennessee | 7845 | LCT5 | 6 | 6 |
| Lagoon Creek | Tennessee | 7845 | LCT6 | 5 | 5 |
| Lagoon Creek | Tennessee | 7845 | LCT7 | 5 | 5 |
| Lagoon Creek | Tennessee | 7845 | LCT8 | 4 | 4 |
| Lagoon Creek | Tennessee | 7845 | LCT9 | 6 | 6 |
| AES Deepwater, Inc. | Texas | 10670 | 01001 | 52 | 52 |
| Air Products Port Arthur | Texas | 55309 | GEN1 | 83 | 83 |
| Air Products Port Arthur | Texas | 55309 | GEN4 | 146 | 146 |
| Air Products Port Arthur | Texas | 55309 | GEN5 | 72 | 72 |
| Alex Ty Cooke Generating Station | Texas | 3602 | 1 | 46 | 46 |
| Alex Ty Cooke Generating Station | Texas | 3602 | 2 | 39 | 39 |
| Barney M. Davis | Texas | 4939 | 1 | 59 | 59 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Barney M. Davis | Texas | 4939 | 3 | 37 | 37 |
| Barney M. Davis | Texas | 4939 | 4 | 33 | 33 |
| Bastrop Clean Energy Center | Texas | 55168 | CTG-1A | 87 | 87 |
| Bastrop Clean Energy Center | Texas | 55168 | CTG-1B | 98 | 98 |
| Bayou Cogeneration Plant | Texas | 10298 | CG801 | | |
| Bayou Cogeneration Plant | Texas | 10298 | CG802 | 57 | 57 |
| Bayou Cogeneration Plant | Texas | 10298 | CG803 | 45 | 45 |
| Bayou Cogeneration Plant | Texas | 10298 | CG804 | 44 | 44 |
| Baytown Energy Center | Texas | 55327 | CTG-1 | 50 | 50 |
| Baytown Energy Center | Texas | 55327 | CTG-2 | 37 | 37 |
| Baytown Energy Center | Texas | 55327 | CTG-3 | 36 | 36 |
| Big Brown | Texas | 3497 | 1 | 818 | 818 |
| Big Brown | Texas | 3497 | 2 | 870 | 870 |
| Blackhawk Station | Texas | 55064 | 001 | 108 | 108 |
| Blackhawk Station | Texas | 55064 | 002 | 114 | 114 |
| Bosque County Power Plant | Texas | 55172 | GT-1 | 146 | 146 |
| Bosque County Power Plant | Texas | 55172 | GT-2 | 188 | 188 |
| Bosque County Power Plant | Texas | 55172 | GT-3 | 81 | 81 |
| Brazos Valley Energy, LP | Texas | 55357 | CTG1 | 35 | 35 |
| Brazos Valley Energy, LP | Texas | 55357 | CTG2 | 37 | 37 |
| C E Newman | Texas | 3574 | BW5 | | |
| C. R. Wing Cogeneration Plant | Texas | 52176 | 1 | 31 | 31 |
| C. R. Wing Cogeneration Plant | Texas | 52176 | 2 | 35 | 35 |
| Calpine Hidalgo Energy Center | Texas | 7762 | HRSG1 | 88 | 88 |
| Calpine Hidalgo Energy Center | Texas | 7762 | HRSG2 | 86 | 86 |
| Cedar Bayou | Texas | 3460 | CBY1 | 228 | 228 |
| Cedar Bayou | Texas | 3460 | CBY2 | 250 | 250 |
| Cedar Bayou 4 | Texas | 56806 | CBY41 | 25 | 25 |
| Cedar Bayou 4 | Texas | 56806 | CBY42 | 22 | 22 |
| Central Utility Plant | Texas | 58151 | GTG01 | 29 | 29 |
| CFB Power Plant | Texas | 56708 | H1101 | 88 | 88 |
| CFB Power Plant | Texas | 56708 | H1201 | 134 | 134 |
| Channel Energy Center | Texas | 55299 | CTG1 | 68 | 68 |
| Channel Energy Center | Texas | 55299 | CTG2 | 42 | 42 |
| Channelview Cogeneration Facility | Texas | 55187 | CHV1 | 38 | 38 |
| Channelview Cogeneration Facility | Texas | 55187 | CHV2 | 36 | 36 |
| Channelview Cogeneration Facility | Texas | 55187 | CHV3 | 36 | 36 |
| Channelview Cogeneration Facility | Texas | 55187 | CHV4 | 38 | 38 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Clear Lake Cogeneration | Texas | 10741 | G102 | 69 | 69 |
| Clear Lake Cogeneration | Texas | 10741 | G103 | 51 | 51 |
| Clear Lake Cogeneration | Texas | 10741 | G104 | 72 | 72 |
| Coleto Creek | Texas | 6178 | 1 | 1,000 | 1,000 |
| Colorado Bend Energy Center | Texas | 56350 | CT1A | 19 | 19 |
| Colorado Bend Energy Center | Texas | 56350 | CT1B | 24 | 24 |
| Colorado Bend Energy Center | Texas | 56350 | CT2A | 21 | 21 |
| Colorado Bend Energy Center | Texas | 56350 | CT2B | 22 | 22 |
| Copper Station | Texas | 9 | CTG-1 | 18 | 18 |
| Corpus Christi | Texas | 50475 | GEN1 | 73 | 73 |
| Corpus Christi Energy Center | Texas | 55206 | CU1 | 122 | 122 |
| Corpus Christi Energy Center | Texas | 55206 | CU2 | 116 | 116 |
| Cottonwood Energy Project | Texas | 55358 | CT1 | 45 | 45 |
| Cottonwood Energy Project | Texas | 55358 | CT2 | 44 | 44 |
| Cottonwood Energy Project | Texas | 55358 | CT3 | 43 | 43 |
| Cottonwood Energy Project | Texas | 55358 | CT4 | 43 | 43 |
| Decker Creek | Texas | 3548 | 1 | 134 | 134 |
| Decker Creek | Texas | 3548 | 2 | 216 | 216 |
| Decker Creek | Texas | 3548 | GT-1A | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-1B | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-2A | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-2B | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-3A | 2 | 2 |
| Decker Creek | Texas | 3548 | GT-3B | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-4A | 3 | 3 |
| Decker Creek | Texas | 3548 | GT-4B | 3 | 3 |
| Decordova | Texas | 8063 | 1 | | |
| Decordova | Texas | 8063 | CT1 | 4 | 4 |
| Decordova | Texas | 8063 | CT2 | 3 | 3 |
| Decordova | Texas | 8063 | CT3 | 3 | 3 |
| Decordova | Texas | 8063 | CT4 | 3 | 3 |
| Deer Park Energy Center | Texas | 55464 | CTG1 | 29 | 29 |
| Deer Park Energy Center | Texas | 55464 | CTG2 | 29 | 29 |
| Deer Park Energy Center | Texas | 55464 | CTG3 | 30 | 30 |
| Deer Park Energy Center | Texas | 55464 | CTG4 | 28 | 28 |
| Deer Park Energy Center | Texas | 55464 | CTG5 | 19 | 19 |
| Eastman Cogeneration Facility | Texas | 55176 | 1 | 88 | 88 |
| Eastman Cogeneration Facility | Texas | 55176 | 2 | 94 | 94 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Ennis Power Company, LLC | Texas | 55223 | GT-1 | 92 | 92 |
| Exelon Laporte Generating Station | Texas | 55365 | GT-1 | 8 | 8 |
| Exelon Laporte Generating Station | Texas | 55365 | GT-2 | 8 | 8 |
| Exelon Laporte Generating Station | Texas | 55365 | GT-3 | 7 | 7 |
| Exelon Laporte Generating Station | Texas | 55365 | GT-4 | 8 | 8 |
| ExxonMobil Beaumont Refinery | Texas | 50625 | 33 | 26 | 26 |
| ExxonMobil Beaumont Refinery | Texas | 50625 | 34 | 21 | 21 |
| Exxonmobil Beaumont Refinery | Texas | 50625 | 61STK1 | 68 | 68 |
| Exxonmobil Beaumont Refinery | Texas | 50625 | 61STK2 | 68 | 68 |
| Exxonmobil Beaumont Refinery | Texas | 50625 | 61STK3 | 68 | 68 |
| FPLE Forney, LP | Texas | 55480 | U1 | 96 | 96 |
| FPLE Forney, LP | Texas | 55480 | U2 | 89 | 89 |
| FPLE Forney, LP | Texas | 55480 | U3 | 98 | 98 |
| FPLE Forney, LP | Texas | 55480 | U4 | 99 | 99 |
| FPLE Forney, LP | Texas | 55480 | U5 | 95 | 95 |
| FPLE Forney, LP | Texas | 55480 | U6 | 90 | 90 |
| Freeport Energy Center | Texas | 56152 | CTG1 | | |
| Freestone Power Generation | Texas | 55226 | GT1 | 85 | 85 |
| Freestone Power Generation | Texas | 55226 | GT2 | 88 | 88 |
| Freestone Power Generation | Texas | 55226 | GT3 | 88 | 88 |
| Freestone Power Generation | Texas | 55226 | GT4 | 81 | 81 |
| Frontera Generation Facility | Texas | 55098 | 1 | 108 | 108 |
| Frontera Generation Facility | Texas | 55098 | 2 | 97 | 97 |
| Gibbons Creek Steam Electric Station | Texas | 6136 | 1 | 702 | 702 |
| Graham | Texas | 3490 | 1 | 30 | 30 |
| Graham | Texas | 3490 | 2 | 60 | 60 |
| Greens Bayou | Texas | 3464 | GBY5 | 75 | 75 |
| Greens Bayou | Texas | 3464 | GBY73 | 7 | 7 |
| Greens Bayou | Texas | 3464 | GBY74 | 6 | 6 |
| Greens Bayou | Texas | 3464 | GBY81 | 7 | 7 |
| Greens Bayou | Texas | 3464 | GBY82 | 4 | 4 |
| Greens Bayou | Texas | 3464 | GBY83 | 7 | 7 |
| Greens Bayou | Texas | 3464 | GBY84 | 8 | 8 |
| Gregory Power Facility | Texas | 55086 | 101 | 126 | 126 |
| Gregory Power Facility | Texas | 55086 | 102 | 119 | 119 |
| Guadalupe Generating Station | Texas | 55153 | CTG-1 | 83 | 83 |
| Guadalupe Generating Station | Texas | 55153 | CTG-2 | 89 | 89 |
| Guadalupe Generating Station | Texas | 55153 | CTG-3 | 79 | 79 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Guadalupe Generating Station | Texas | 55153 | CTG-4 | 86 | 86 |
| H W Pirkey Power Plant | Texas | 7902 | 1 | 1,090 | 1,090 |
| Handley Generating Station | Texas | 3491 | 3 | 53 | 53 |
| Handley Generating Station | Texas | 3491 | 4 | 14 | 14 |
| Handley Generating Station | Texas | 3491 | 5 | 15 | 15 |
| Hardin County Peaking Facility | Texas | 56604 | HCCT1 | 9 | 9 |
| Hardin County Peaking Facility | Texas | 56604 | HCCT2 | 11 | 11 |
| Harrington Station | Texas | 6193 | 061B | 452 | 452 |
| Harrington Station | Texas | 6193 | 062B | 489 | 489 |
| Harrington Station | Texas | 6193 | 063B | 457 | 457 |
| Harrison County Power Project | Texas | 55664 | GT-1 | 25 | 25 |
| Harrison County Power Project | Texas | 55664 | GT-2 | 26 | 26 |
| Hays Energy Project | Texas | 55144 | STK1 | 33 | 33 |
| Hays Energy Project | Texas | 55144 | STK2 | 32 | 32 |
| Hays Energy Project | Texas | 55144 | STK3 | 33 | 33 |
| Hays Energy Project | Texas | 55144 | STK4 | 33 | 33 |
| J K Spruce | Texas | 7097 | **1 | 893 | 893 |
| J K Spruce | Texas | 7097 | **2 | 569 | 569 |
| J Robert Massengale Generating Station | Texas | 3604 | GT1 | 24 | 24 |
| J T Deely | Texas | 6181 | 1 | 641 | 641 |
| J T Deely | Texas | 6181 | 2 | 650 | 650 |
| Jack County Generation Facility | Texas | 55230 | CT-1 | 47 | 47 |
| Jack County Generation Facility | Texas | 55230 | CT-2 | 52 | 52 |
| Jack County Generation Facility | Texas | 55230 | CT-3 | 32 | 32 |
| Jack County Generation Facility | Texas | 55230 | CT-4 | 16 | 16 |
| JCO Oxides Olefins Plant | Texas | 54637 | GCG1 | 133 | 133 |
| JCO Oxides Olefins Plant | Texas | 54637 | GCG2 | 133 | 133 |
| Johnson County Generation Facility | Texas | 54817 | EAST | 86 | 86 |
| Jones Station | Texas | 3482 | 151B | 211 | 211 |
| Jones Station | Texas | 3482 | 152B | 187 | 187 |
| Jones Station | Texas | 3482 | 153T | 14 | 14 |
| Jones Station | Texas | 3482 | 154T | 13 | 13 |
| Knox Lee Power Plant | Texas | 3476 | 2 | 7 | 7 |
| Knox Lee Power Plant | Texas | 3476 | 3 | 8 | 8 |
| Knox Lee Power Plant | Texas | 3476 | 4 | 20 | 20 |
| Knox Lee Power Plant | Texas | 3476 | 5 | 117 | 117 |
| Lake Creek | Texas | 3502 | 1 | | |
| Lake Creek | Texas | 3502 | 2 | | |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Lake Hubbard | Texas | 3452 | 1 | 41 | 41 |
| Lake Hubbard | Texas | 3452 | 2 | 22 | 22 |
| Lamar Power (Paris) | Texas | 55097 | 1 | 78 | 78 |
| Lamar Power (Paris) | Texas | 55097 | 2 | 77 | 77 |
| Lamar Power (Paris) | Texas | 55097 | 3 | 74 | 74 |
| Lamar Power (Paris) | Texas | 55097 | 4 | 72 | 72 |
| Laredo | Texas | 3439 | 4 | 7 | 7 |
| Laredo | Texas | 3439 | 5 | 7 | 7 |
| Leon Creek | Texas | 3609 | 3 | | |
| Leon Creek | Texas | 3609 | 4 | | |
| Leon Creek | Texas | 3609 | CGT1 | 2 | 2 |
| Leon Creek | Texas | 3609 | CGT2 | 3 | 3 |
| Leon Creek | Texas | 3609 | CGT3 | 3 | 3 |
| Leon Creek | Texas | 3609 | CGT4 | 3 | 3 |
| Lewis Creek | Texas | 3457 | 1 | 92 | 92 |
| Lewis Creek | Texas | 3457 | 2 | 81 | 81 |
| Limestone | Texas | 298 | LIM1 | 1,206 | 1,206 |
| Limestone | Texas | 298 | LIM2 | 1,329 | 1,329 |
| Lone Star Power Plant | Texas | 3477 | 1 | 12 | 12 |
| Lost Pines 1 | Texas | 55154 | 1 | 49 | 49 |
| Lost Pines 1 | Texas | 55154 | 2 | 54 | 54 |
| Magic Valley Generating Station | Texas | 55123 | CTG-1 | 133 | 133 |
| Magic Valley Generating Station | Texas | 55123 | CTG-2 | 124 | 124 |
| Martin Lake | Texas | 6146 | 1 | 1,166 | 1,166 |
| Martin Lake | Texas | 6146 | 2 | 1,126 | 1,126 |
| Martin Lake | Texas | 6146 | 3 | 1,195 | 1,195 |
| Midlothian Energy | Texas | 55091 | STK1 | 29 | 29 |
| Midlothian Energy | Texas | 55091 | STK2 | 30 | 30 |
| Midlothian Energy | Texas | 55091 | STK3 | 29 | 29 |
| Midlothian Energy | Texas | 55091 | STK4 | 26 | 26 |
| Midlothian Energy | Texas | 55091 | STK5 | 36 | 36 |
| Midlothian Energy | Texas | 55091 | STK6 | 33 | 33 |
| Monticello | Texas | 6147 | 1 | 729 | 729 |
| Monticello | Texas | 6147 | 2 | 730 | 730 |
| Monticello | Texas | 6147 | 3 | 1,055 | 1,055 |
| Moore County Station | Texas | 3483 | 3 | 32 | 32 |
| Morgan Creek | Texas | 3492 | 5 | | |
| Morgan Creek | Texas | 3492 | 6 | | |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Morgan Creek | Texas | 3492 | CT1 | 3 | 3 |
| Morgan Creek | Texas | 3492 | CT2 | 5 | 5 |
| Morgan Creek | Texas | 3492 | CT3 | 4 | 4 |
| Morgan Creek | Texas | 3492 | CT4 | 2 | 2 |
| Morgan Creek | Texas | 3492 | CT5 | 2 | 2 |
| Morgan Creek | Texas | 3492 | CT6 | 3 | 3 |
| Mountain Creek Generating Station | Texas | 3453 | 6 | 24 | 24 |
| Mountain Creek Generating Station | Texas | 3453 | 7 | 29 | 29 |
| Mountain Creek Generating Station | Texas | 3453 | 8 | 51 | 51 |
| Mustang Station | Texas | 55065 | 1 | 105 | 105 |
| Mustang Station | Texas | 55065 | 2 | 106 | 106 |
| Mustang Station (56326) | Texas | 56326 | GEN3 | 7 | 7 |
| Mustang Station Units 4 and 5 | Texas | 56326 | GEN1 | 29 | 29 |
| Mustang Station Units 4 and 5 | Texas | 56326 | GEN2 | 11 | 11 |
| Nacogdoches Power LLC | Texas | 55708 | BFB-1 | 63 | 63 |
| NAFTA Region Olefins Complex Cogen Fac | Texas | 55122 | UN1 | 72 | 72 |
| NAFTA Region Olefins Complex Cogen Fac | Texas | 55122 | UN2 | 72 | 72 |
| New Gulf Power Facility | Texas | 50137 | 1 | 3 | 3 |
| Newman | Texas | 3456 | 1 | 73 | 73 |
| Newman | Texas | 3456 | 2 | 77 | 77 |
| Newman | Texas | 3456 | 3 | 89 | 89 |
| Newman | Texas | 3456 | **4 | 116 | 116 |
| Newman | Texas | 3456 | **5 | 110 | 110 |
| Newman | Texas | 3456 | GT-6A | 17 | 17 |
| Newman | Texas | 3456 | GT-6B | 20 | 20 |
| Nichols Station | Texas | 3484 | 141B | 67 | 67 |
| Nichols Station | Texas | 3484 | 142B | 76 | 76 |
| Nichols Station | Texas | 3484 | 143B | 122 | 122 |
| Nueces Bay | Texas | 3441 | 8 | 28 | 28 |
| Nueces Bay | Texas | 3441 | 9 | 25 | 25 |
| O W Sommers | Texas | 3611 | 1 | 145 | 145 |
| O W Sommers | Texas | 3611 | 2 | 158 | 158 |
| Oak Grove | Texas | 6180 | 1 | 1,055 | 1,055 |
| Oak Grove | Texas | 6180 | 2 | 1,066 | 1,066 |
| Odessa-Ector Generating Station | Texas | 55215 | GT1 | 93 | 93 |
| Odessa-Ector Generating Station | Texas | 55215 | GT2 | 84 | 84 |
| Odessa-Ector Generating Station | Texas | 55215 | GT3 | 108 | 108 |
| Odessa-Ector Generating Station | Texas | 55215 | GT4 | 93 | 93 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Oklaunion Power Station | Texas | 127 | 1 | 918 | 918 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG101 | 29 | 29 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG201 | 24 | 24 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG301 | 15 | 15 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG401 | 20 | 20 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG501 | 16 | 16 |
| Optim Energy Altura Cogen, LLC | Texas | 50815 | ENG601 | 46 | 46 |
| Oyster Creek Unit VIII | Texas | 54676 | G81 | 146 | 146 |
| Oyster Creek Unit VIII | Texas | 54676 | G82 | 62 | 62 |
| Oyster Creek Unit VIII | Texas | 54676 | G83 | 62 | 62 |
| Pampa Power Plant | Texas | 7678 | BL09A1 | | |
| Pampa Power Plant | Texas | 7678 | BL10A1 | | |
| Pampa Power Plant | Texas | 7678 | BL11A1 | | |
| Panda Sherman Power Station | Texas | 58005 | CTG1 | 13 | 13 |
| Panda Sherman Power Station | Texas | 58005 | CTG2 | 13 | 13 |
| Panda Temple Power Station | Texas | 58001 | CTG1 | 24 | 24 |
| Panda Temple Power Station | Texas | 58001 | CTG2 | 21 | 21 |
| Paris Energy Center | Texas | 50109 | HRSG1 | 59 | 59 |
| Paris Energy Center | Texas | 50109 | HRSG2 | 58 | 58 |
| Pasadena Power Plant | Texas | 55047 | CG-1 | 55 | 55 |
| Pasadena Power Plant | Texas | 55047 | CG-2 | 88 | 88 |
| Pasadena Power Plant | Texas | 55047 | CG-3 | 136 | 136 |
| Permian Basin | Texas | 3494 | 5 | | |
| Permian Basin | Texas | 3494 | 6 | | |
| Permian Basin | Texas | 3494 | CT1 | 39 | 39 |
| Permian Basin | Texas | 3494 | CT2 | 20 | 20 |
| Permian Basin | Texas | 3494 | CT3 | 34 | 34 |
| Permian Basin | Texas | 3494 | CT4 | 32 | 32 |
| Permian Basin | Texas | 3494 | CT5 | 24 | 24 |
| Plant X | Texas | 3485 | 111B | 40 | 40 |
| Plant X | Texas | 3485 | 112B | 64 | 64 |
| Plant X | Texas | 3485 | 113B | 67 | 67 |
| Plant X | Texas | 3485 | 114B | 187 | 187 |
| Port Neches Plant | Texas | 54748 | G1 | 74 | 74 |
| Power Lane Steam Plant | Texas | 4195 | 2 | 6 | 6 |
| Power Lane Steam Plant | Texas | 4195 | 3 | 8 | 8 |
| Quail Run Energy Center | Texas | 56349 | CT1A | 16 | 16 |
| Quail Run Energy Center | Texas | 56349 | CT1B | 15 | 15 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Quail Run Energy Center | Texas | 56349 | CT2A | 16 | 16 |
| Quail Run Energy Center | Texas | 56349 | CT2B | 14 | 14 |
| R W Miller | Texas | 3628 | 1 | 9 | 9 |
| R W Miller | Texas | 3628 | 2 | 25 | 25 |
| R W Miller | Texas | 3628 | 3 | 67 | 67 |
| R W Miller | Texas | 3628 | **4 | 20 | 20 |
| R W Miller | Texas | 3628 | **5 | 19 | 19 |
| Ray Olinger | Texas | 3576 | BW2 | 17 | 17 |
| Ray Olinger | Texas | 3576 | BW3 | 17 | 17 |
| Ray Olinger | Texas | 3576 | CE1 | 7 | 7 |
| Ray Olinger | Texas | 3576 | GE4 | 2 | 2 |
| Rio Nogales Power Project, LP | Texas | 55137 | CTG-1 | 76 | 76 |
| Rio Nogales Power Project, LP | Texas | 55137 | CTG-2 | 70 | 70 |
| Rio Nogales Power Project, LP | Texas | 55137 | CTG-3 | 70 | 70 |
| Roland C. Dansby Power Plant | Texas | 6243 | 1 | 33 | 33 |
| Roland C. Dansby Power Plant | Texas | 6243 | 2 | 2 | 2 |
| Roland C. Dansby Power Plant | Texas | 6243 | 3 | 3 | 3 |
| Sabine | Texas | 3459 | 1 | 163 | 163 |
| Sabine | Texas | 3459 | 2 | 125 | 125 |
| Sabine | Texas | 3459 | 3 | 253 | 253 |
| Sabine | Texas | 3459 | 4 | 457 | 457 |
| Sabine | Texas | 3459 | 5 | 226 | 226 |
| Sabine Cogeneration Facility | Texas | 55104 | SAB-1 | 14 | 14 |
| Sabine Cogeneration Facility | Texas | 55104 | SAB-2 | 14 | 14 |
| Sam Bertron | Texas | 3468 | SRB1 | 5 | 5 |
| Sam Bertron | Texas | 3468 | SRB2 | 20 | 20 |
| Sam Bertron | Texas | 3468 | SRB3 | 39 | 39 |
| Sam Bertron | Texas | 3468 | SRB4 | 32 | 32 |
| Sam Rayburn Plant | Texas | 3631 | CT7 | 7 | 7 |
| Sam Rayburn Plant | Texas | 3631 | CT8 | 6 | 6 |
| Sam Rayburn Plant | Texas | 3631 | CT9 | 6 | 6 |
| Sam Seymour | Texas | 6179 | 1 | 871 | 871 |
| Sam Seymour | Texas | 6179 | 2 | 925 | 925 |
| Sam Seymour | Texas | 6179 | 3 | 654 | 654 |
| San Jacinto County Peaking Facility | Texas | 56603 | SJCCT1 | 27 | 27 |
| San Jacinto County Peaking Facility | Texas | 56603 | SJCCT2 | 21 | 21 |
| San Jacinto Steam Electric Station | Texas | 7325 | SJS1 | 32 | 32 |
| San Jacinto Steam Electric Station | Texas | 7325 | SJS2 | 34 | 34 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| San Miguel | Texas | 6183 | SM-1 | 698 | 698 |
| Sand Hill Energy Center | Texas | 7900 | SH1 | 5 | 5 |
| Sand Hill Energy Center | Texas | 7900 | SH2 | 4 | 4 |
| Sand Hill Energy Center | Texas | 7900 | SH3 | 4 | 4 |
| Sand Hill Energy Center | Texas | 7900 | SH4 | 4 | 4 |
| Sand Hill Energy Center | Texas | 7900 | SH5 | 51 | 51 |
| Sand Hill Energy Center | Texas | 7900 | SH6 | 3 | 3 |
| Sand Hill Energy Center | Texas | 7900 | SH7 | 3 | 3 |
| Sandow | Texas | 6648 | 4 | 949 | 949 |
| Sandow Station | Texas | 52071 | 5A | 321 | 321 |
| Sandow Station | Texas | 52071 | 5B | 317 | 317 |
| Sandy Creek Energy Station | Texas | 56611 | S01 | 676 | 676 |
| Silas Ray | Texas | 3559 | 9 | 21 | 21 |
| Silas Ray | Texas | 3559 | 10 | 2 | 2 |
| Sim Gideon | Texas | 3601 | 1 | 20 | 20 |
| Sim Gideon | Texas | 3601 | 2 | 17 | 17 |
| Sim Gideon | Texas | 3601 | 3 | 115 | 115 |
| South Houston Green Power Site | Texas | 55470 | EPN801 | 45 | 45 |
| South Houston Green Power Site | Texas | 55470 | EPN802 | 47 | 47 |
| South Houston Green Power Site | Texas | 55470 | EPN803 | 42 | 42 |
| Spencer | Texas | 4266 | 4 | 5 | 5 |
| Spencer | Texas | 4266 | 5 | 5 | 5 |
| SRW Cogen Limited Partnership | Texas | 55120 | CTG-1 | 40 | 40 |
| SRW Cogen Limited Partnership | Texas | 55120 | CTG-2 | 46 | 46 |
| Stryker Creek | Texas | 3504 | 1 | 16 | 16 |
| Stryker Creek | Texas | 3504 | 2 | 80 | 80 |
| Sweeny Cogeneration Facility | Texas | 55015 | 1 | 239 | 239 |
| Sweeny Cogeneration Facility | Texas | 55015 | 2 | 163 | 163 |
| Sweeny Cogeneration Facility | Texas | 55015 | 3 | 65 | 65 |
| Sweeny Cogeneration Facility | Texas | 55015 | 4 | 188 | 188 |
| Sweetwater Generating Plant | Texas | 50615 | GT01 | | |
| Sweetwater Generating Plant | Texas | 50615 | GT02 | | |
| Sweetwater Generating Plant | Texas | 50615 | GT03 | | |
| T C Ferguson Power Plant | Texas | 4937 | 1 | 96 | 96 |
| T C Ferguson Power Plant | Texas | 4937 | CT-1 | 17 | 17 |
| T C Ferguson Power Plant | Texas | 4937 | CT-2 | 15 | 15 |
| T H Wharton | Texas | 3469 | THW31 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW32 | 22 | 22 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| T H Wharton | Texas | 3469 | THW33 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW34 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW41 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW42 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW43 | 8 | 8 |
| T H Wharton | Texas | 3469 | THW44 | 26 | 26 |
| T H Wharton | Texas | 3469 | THW51 | 6 | 6 |
| T H Wharton | Texas | 3469 | THW52 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW53 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW54 | 6 | 6 |
| T H Wharton | Texas | 3469 | THW55 | 7 | 7 |
| T H Wharton | Texas | 3469 | THW56 | 6 | 6 |
| TECO CHP-1 | Texas | 57504 | CHP1 | 16 | 16 |
| Tenaska Frontier Generation Station | Texas | 55062 | 1 | 105 | 105 |
| Tenaska Frontier Generation Station | Texas | 55062 | 2 | 114 | 114 |
| Tenaska Frontier Generation Station | Texas | 55062 | 3 | 112 | 112 |
| Tenaska Gateway Generating Station | Texas | 55132 | OGTDB1 | 85 | 85 |
| Tenaska Gateway Generating Station | Texas | 55132 | OGTDB2 | 82 | 82 |
| Tenaska Gateway Generating Station | Texas | 55132 | OGTDB3 | 81 | 81 |
| Texas City Cogeneration | Texas | 52088 | GT-A | 55 | 55 |
| Texas City Cogeneration | Texas | 52088 | GT-B | 59 | 59 |
| Texas City Cogeneration | Texas | 52088 | GT-C | 60 | 60 |
| Texas Petrochemicals | Texas | 50229 | TPCBLR | 193 | 193 |
| Tolk Station | Texas | 6194 | 171B | 732 | 732 |
| Tolk Station | Texas | 6194 | 172B | 834 | 834 |
| Tradinghouse | Texas | 3506 | 1 | | |
| Tradinghouse | Texas | 3506 | 2 | | |
| Trinidad | Texas | 3507 | 9 | 25 | 25 |
| Twin Oaks | Texas | 7030 | U1 | 274 | 274 |
| Twin Oaks | Texas | 7030 | U2 | 257 | 257 |
| Union Carbide Seadrift Cogen | Texas | 50150 | GE11 | 41 | 41 |
| Union Carbide Seadrift Cogen | Texas | 50150 | GEN6 | 34 | 34 |
| Union Carbide Seadrift Cogen | Texas | 50150 | GEN8 | 29 | 29 |
| V H Braunig | Texas | 3612 | 1 | 52 | 52 |
| V H Braunig | Texas | 3612 | 2 | 41 | 41 |
| V H Braunig | Texas | 3612 | 3 | 159 | 159 |
| V H Braunig | Texas | 3612 | CGT5 | 2 | 2 |
| V H Braunig | Texas | 3612 | CGT6 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| V H Braunig | Texas | 3612 | CGT7 | 2 | 2 |
| V H Braunig | Texas | 3612 | CGT8 | 2 | 2 |
| V H Braunig | Texas | 3612 | CT01 | 78 | 78 |
| V H Braunig | Texas | 3612 | CT02 | 77 | 77 |
| Valley (TXU) | Texas | 3508 | 1 | | |
| Valley (TXU) | Texas | 3508 | 2 | | |
| Valley (TXU) | Texas | 3508 | 3 | | |
| Victoria Power Station | Texas | 3443 | 9 | 43 | 43 |
| W A Parish | Texas | 3470 | CTSC | 1 | 1 |
| W A Parish | Texas | 3470 | WAP1 | 31 | 31 |
| W A Parish | Texas | 3470 | WAP2 | 36 | 36 |
| W A Parish | Texas | 3470 | WAP3 | 73 | 73 |
| W A Parish | Texas | 3470 | WAP4 | 208 | 208 |
| W A Parish | Texas | 3470 | WAP5 | 653 | 653 |
| W A Parish | Texas | 3470 | WAP6 | 768 | 768 |
| W A Parish | Texas | 3470 | WAP7 | 552 | 552 |
| W A Parish | Texas | 3470 | WAP8 | 509 | 509 |
| W B Tuttle | Texas | 3613 | 1 | | |
| W B Tuttle | Texas | 3613 | 3 | | |
| W B Tuttle | Texas | 3613 | 4 | | |
| Welsh Power Plant | Texas | 6139 | 1 | 651 | 651 |
| Welsh Power Plant | Texas | 6139 | 2 | 651 | 651 |
| Welsh Power Plant | Texas | 6139 | 3 | 745 | 745 |
| Wilkes Power Plant | Texas | 3478 | 1 | 83 | 83 |
| Wilkes Power Plant | Texas | 3478 | 2 | 151 | 151 |
| Wilkes Power Plant | Texas | 3478 | 3 | 157 | 157 |
| Winchester Power Park | Texas | 56674 | 1 | 4 | 4 |
| Winchester Power Park | Texas | 56674 | 2 | 2 | 2 |
| Winchester Power Park | Texas | 56674 | 3 | 1 | 1 |
| Winchester Power Park | Texas | 56674 | 4 | 2 | 2 |
| Wise County Power Company, LLC | Texas | 55320 | GT-1 | 64 | 64 |
| Wise County Power Company, LLC | Texas | 55320 | GT-2 | 62 | 62 |
| Wolf Hollow I, LP | Texas | 55139 | CTG1 | 123 | 123 |
| Wolf Hollow I, LP | Texas | 55139 | CTG2 | 124 | 124 |
| Altavista Power Station | Virginia | 10773 | 1 | 58 | 58 |
| Altavista Power Station | Virginia | 10773 | 2 | 53 | 53 |
| Bear Garden Generating Station | Virginia | 56807 | 1A | 26 | 26 |
| Bear Garden Generating Station | Virginia | 56807 | 1B | 26 | 26 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bellemeade Power Station | Virginia | 50966 | 1 | 52 | 52 |
| Bellemeade Power Station | Virginia | 50966 | 2 | 52 | 52 |
| Birchwood Power Facility | Virginia | 54304 | 001 | 169 | 169 |
| Bremo Power Station | Virginia | 3796 | 3 | 52 | 52 |
| Bremo Power Station | Virginia | 3796 | 4 | 134 | 134 |
| Buchanan Units 1 & 2 | Virginia | 55738 | 1 | 9 | 9 |
| Buchanan Units 1 & 2 | Virginia | 55738 | 2 | 9 | 9 |
| Chesapeake Energy Center | Virginia | 3803 | 1 | 74 | 74 |
| Chesapeake Energy Center | Virginia | 3803 | 2 | 91 | 91 |
| Chesapeake Energy Center | Virginia | 3803 | 3 | 198 | 198 |
| Chesapeake Energy Center | Virginia | 3803 | 4 | 223 | 223 |
| Chesterfield Power Station | Virginia | 3797 | 3 | 45 | 45 |
| Chesterfield Power Station | Virginia | 3797 | 4 | 205 | 205 |
| Chesterfield Power Station | Virginia | 3797 | 5 | 514 | 514 |
| Chesterfield Power Station | Virginia | 3797 | 6 | 762 | 762 |
| Chesterfield Power Station | Virginia | 3797 | 7 | 273 | 273 |
| Chesterfield Power Station | Virginia | 3797 | **8A | 287 | 287 |
| Clinch River | Virginia | 3775 | 1 | 112 | 112 |
| Clinch River | Virginia | 3775 | 2 | 122 | 122 |
| Clinch River | Virginia | 3775 | 3 | 61 | 61 |
| Clover Power Station | Virginia | 7213 | 1 | 735 | 735 |
| Clover Power Station | Virginia | 7213 | 2 | 752 | 752 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR01A | 29 | 29 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR01B | 24 | 24 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR01C | 30 | 30 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR02A | 18 | 18 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR02B | 18 | 18 |
| Cogentrix-Hopewell | Virginia | 10377 | BLR02C | 14 | 14 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR01A | 8 | 8 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR01B | 7 | 7 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR01C | 7 | 7 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR02A | 7 | 7 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR02B | 7 | 7 |
| Cogentrix-Portsmouth | Virginia | 10071 | BLR02C | 7 | 7 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-001 | 8 | 8 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-002 | 4 | 4 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-003 | 5 | 5 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-004 | 2 | 2 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Commonwealth Chesapeake | Virginia | 55381 | CT-005 | 2 | 2 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-006 | 1 | 1 |
| Commonwealth Chesapeake | Virginia | 55381 | CT-007 | 1 | 1 |
| Darbytown Combustion Turbine | Virginia | 7212 | 1 | 21 | 21 |
| Darbytown Combustion Turbine | Virginia | 7212 | 2 | 18 | 18 |
| Darbytown Combustion Turbine | Virginia | 7212 | 3 | 20 | 20 |
| Darbytown Combustion Turbine | Virginia | 7212 | 4 | 23 | 23 |
| Doswell Limited Partnership | Virginia | 52019 | 501 | 80 | 80 |
| Doswell Limited Partnership | Virginia | 52019 | 502 | 73 | 73 |
| Doswell Limited Partnership | Virginia | 52019 | 601 | 69 | 69 |
| Doswell Limited Partnership | Virginia | 52019 | 602 | 68 | 68 |
| Doswell Limited Partnership | Virginia | 52019 | CT1 | 27 | 27 |
| Elizabeth River Combustion Turbine Sta | Virginia | 52087 | CT-1 | 22 | 22 |
| Elizabeth River Combustion Turbine Sta | Virginia | 52087 | CT-2 | 20 | 20 |
| Elizabeth River Combustion Turbine Sta | Virginia | 52087 | CT-3 | 22 | 22 |
| Glen Lyn | Virginia | 3776 | 6 | 51 | 51 |
| Glen Lyn | Virginia | 3776 | 51 | 7 | 7 |
| Glen Lyn | Virginia | 3776 | 52 | 10 | 10 |
| Gordonsville Power Station | Virginia | 54844 | 1 | 51 | 51 |
| Gordonsville Power Station | Virginia | 54844 | 2 | 48 | 48 |
| Gravel Neck Combustion Turbine | Virginia | 7032 | 3 | 6 | 6 |
| Gravel Neck Combustion Turbine | Virginia | 7032 | 4 | 22 | 22 |
| Gravel Neck Combustion Turbine | Virginia | 7032 | 5 | 19 | 19 |
| Gravel Neck Combustion Turbine | Virginia | 7032 | 6 | 9 | 9 |
| Hopewell Cogeneration Facility | Virginia | 10633 | 1 | 107 | 107 |
| Hopewell Cogeneration Facility | Virginia | 10633 | 2 | 101 | 101 |
| Hopewell Cogeneration Facility | Virginia | 10633 | 3 | 95 | 95 |
| Hopewell Power Station | Virginia | 10771 | 1 | 47 | 47 |
| Hopewell Power Station | Virginia | 10771 | 2 | 46 | 46 |
| Ladysmith Combustion Turbine Sta | Virginia | 7838 | 1 | 18 | 18 |
| Ladysmith Combustion Turbine Sta | Virginia | 7838 | 2 | 16 | 16 |
| Ladysmith Combustion Turbine Sta | Virginia | 7838 | 3 | 15 | 15 |
| Ladysmith Combustion Turbine Sta | Virginia | 7838 | 4 | 17 | 17 |
| Ladysmith Combustion Turbine Sta | Virginia | 7839 | 5 | 21 | 21 |
| Louisa Generation Facility | Virginia | 7837 | EU1 | 4 | 4 |
| Louisa Generation Facility | Virginia | 7837 | EU2 | 4 | 4 |
| Louisa Generation Facility | Virginia | 7837 | EU3 | 4 | 4 |
| Louisa Generation Facility | Virginia | 7837 | EU4 | 5 | 5 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Louisa Generation Facility | Virginia | 7837 | EU5 | 20 | 20 |
| Marsh Run Generation Facility | Virginia | 7836 | EU1 | 24 | 24 |
| Marsh Run Generation Facility | Virginia | 7836 | EU2 | 21 | 21 |
| Marsh Run Generation Facility | Virginia | 7836 | EU3 | 23 | 23 |
| Mecklenburg Power Station | Virginia | 52007 | 1 | 71 | 71 |
| Mecklenburg Power Station | Virginia | 52007 | 2 | 70 | 70 |
| Possum Point Power Station | Virginia | 3804 | 3 | 24 | 24 |
| Possum Point Power Station | Virginia | 3804 | 4 | 65 | 65 |
| Possum Point Power Station | Virginia | 3804 | 5 | 53 | 53 |
| Possum Point Power Station | Virginia | 3804 | 6A | 35 | 35 |
| Possum Point Power Station | Virginia | 3804 | 6B | 34 | 34 |
| Potomac River | Virginia | 3788 | 1 | 15 | 15 |
| Potomac River | Virginia | 3788 | 2 | 14 | 14 |
| Potomac River | Virginia | 3788 | 3 | 33 | 33 |
| Potomac River | Virginia | 3788 | 4 | 25 | 25 |
| Potomac River | Virginia | 3788 | 5 | 33 | 33 |
| Remington Combustion Turbine Station | Virginia | 7839 | 1 | 25 | 25 |
| Remington Combustion Turbine Station | Virginia | 7839 | 2 | 21 | 21 |
| Remington Combustion Turbine Station | Virginia | 7839 | 3 | 20 | 20 |
| Remington Combustion Turbine Station | Virginia | 7839 | 4 | 22 | 22 |
| Southampton Power Station | Virginia | 10774 | 1 | 44 | 44 |
| Southampton Power Station | Virginia | 10774 | 2 | 44 | 44 |
| Spruance Genco, LLC | Virginia | 54081 | BLR01A | 45 | 45 |
| Spruance Genco, LLC | Virginia | 54081 | BLR01B | 50 | 50 |
| Spruance Genco, LLC | Virginia | 54081 | BLR02A | 43 | 43 |
| Spruance Genco, LLC | Virginia | 54081 | BLR02B | 42 | 42 |
| Spruance Genco, LLC | Virginia | 54081 | BLR03A | 44 | 44 |
| Spruance Genco, LLC | Virginia | 54081 | BLR03B | 46 | 46 |
| Spruance Genco, LLC | Virginia | 54081 | BLR04A | 46 | 46 |
| Spruance Genco, LLC | Virginia | 54081 | BLR04B | 44 | 44 |
| Tasley Energy Center | Virginia | 3785 | TA10 | 1 | 1 |
| Tenaska Virginia Generating Station | Virginia | 55439 | CTGDB1 | 25 | 25 |
| Tenaska Virginia Generating Station | Virginia | 55439 | CTGDB2 | 26 | 26 |
| Tenaska Virginia Generating Station | Virginia | 55439 | CTGDB3 | 24 | 24 |
| Virginia City Hybrid Energy Center | Virginia | 56808 | 1 | 252 | 252 |
| Virginia City Hybrid Energy Center | Virginia | 56808 | 2 | 291 | 291 |
| Warren County Power Station | Virginia | 55939 | 1A | 20 | 20 |
| Warren County Power Station | Virginia | 55939 | 1B | 21 | 21 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Warren County Power Station | Virginia | 55939 | 1C | 24 | 24 |
| Wolf Hills Energy | Virginia | 55285 | WH01 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH02 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH03 | 2 | 2 |
| Wolf Hills Energy | Virginia | 55285 | WH04 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH05 | 2 | 2 |
| Wolf Hills Energy | Virginia | 55285 | WH06 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH07 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH08 | 3 | 3 |
| Wolf Hills Energy | Virginia | 55285 | WH09 | 2 | 2 |
| Wolf Hills Energy | Virginia | 55285 | WH10 | 3 | 3 |
| Yorktown Power Station | Virginia | 3809 | 1 | 130 | 130 |
| Yorktown Power Station | Virginia | 3809 | 2 | 150 | 150 |
| Yorktown Power Station | Virginia | 3809 | 3 | 95 | 95 |
| Albright Power Station | West Virginia | 3942 | 1 | 19 | 19 |
| Albright Power Station | West Virginia | 3942 | 2 | 17 | 17 |
| Albright Power Station | West Virginia | 3942 | 3 | 98 | 98 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS01 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS02 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS03 | 2 | 2 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS04 | 2 | 2 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS05 | 2 | 2 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS06 | 2 | 2 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS07 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS08 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS09 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS10 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS11 | 3 | 3 |
| Big Sandy Peaker Plant | West Virginia | 55284 | GS12 | 3 | 3 |
| Ceredo Generating Station | West Virginia | 55276 | 01 | 2 | 2 |
| Ceredo Generating Station | West Virginia | 55276 | 02 | 2 | 2 |
| Ceredo Generating Station | West Virginia | 55276 | 03 | 2 | 2 |
| Ceredo Generating Station | West Virginia | 55276 | 04 | 2 | 2 |
| Ceredo Generating Station | West Virginia | 55276 | 05 | 2 | 2 |
| Ceredo Generating Station | West Virginia | 55276 | 06 | 2 | 2 |
| Fort Martin Power Station | West Virginia | 3943 | 1 | 912 | 912 |
| Fort Martin Power Station | West Virginia | 3943 | 2 | 875 | 875 |
| Grant Town Power Plant | West Virginia | 10151 | 1A | 111 | 111 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Grant Town Power Plant | West Virginia | 10151 | 1B | 122 | 122 |
| Harrison Power Station | West Virginia | 3944 | 1 | 1,060 | 1,060 |
| Harrison Power Station | West Virginia | 3944 | 2 | 955 | 955 |
| Harrison Power Station | West Virginia | 3944 | 3 | 1,065 | 1,065 |
| John E Amos | West Virginia | 3935 | 1 | 655 | 655 |
| John E Amos | West Virginia | 3935 | 2 | 606 | 606 |
| John E Amos | West Virginia | 3935 | 3 | 1,374 | 1,374 |
| Kammer | West Virginia | 3947 | 1 | 150 | 150 |
| Kammer | West Virginia | 3947 | 2 | 138 | 138 |
| Kammer | West Virginia | 3947 | 3 | 129 | 129 |
| Kanawha River | West Virginia | 3936 | 1 | 246 | 246 |
| Kanawha River | West Virginia | 3936 | 2 | 148 | 148 |
| Longview Power | West Virginia | 56671 | 001 | 508 | 508 |
| Mitchell (WV) | West Virginia | 3948 | 1 | 700 | 700 |
| Mitchell (WV) | West Virginia | 3948 | 2 | 824 | 824 |
| Morgantown Energy Facility | West Virginia | 10743 | CFB1 | 79 | 79 |
| Morgantown Energy Facility | West Virginia | 10743 | CFB2 | 80 | 80 |
| Mount Storm Power Station | West Virginia | 3954 | 1 | 625 | 625 |
| Mount Storm Power Station | West Virginia | 3954 | 2 | 697 | 697 |
| Mount Storm Power Station | West Virginia | 3954 | 3 | 695 | 695 |
| Mountaineer (1301) | West Virginia | 6264 | 1 | 1,979 | 1,979 |
| North Branch Power Station | West Virginia | 7537 | 1A | | |
| North Branch Power Station | West Virginia | 7537 | 1B | | |
| Phil Sporn | West Virginia | 3938 | 11 | 86 | 86 |
| Phil Sporn | West Virginia | 3938 | 21 | 119 | 119 |
| Phil Sporn | West Virginia | 3938 | 31 | 104 | 104 |
| Phil Sporn | West Virginia | 3938 | 41 | 43 | 43 |
| Phil Sporn | West Virginia | 3938 | 51 | | |
| Pleasants Energy, LLC | West Virginia | 55349 | 1 | 50 | 50 |
| Pleasants Energy, LLC | West Virginia | 55349 | 2 | 57 | 57 |
| Pleasants Power Station | West Virginia | 6004 | 1 | 1,014 | 1,014 |
| Pleasants Power Station | West Virginia | 6004 | 2 | 1,005 | 1,005 |
| Rivesville Power Station | West Virginia | 3945 | 7 | | |
| Rivesville Power Station | West Virginia | 3945 | 8 | 4 | 4 |
| Willow Island Power Station | West Virginia | 3946 | 1 | 19 | 19 |
| Willow Island Power Station | West Virginia | 3946 | 2 | 47 | 47 |
| Alma | Wisconsin | 4140 | B4 | 7 | 7 |
| Alma | Wisconsin | 4140 | B5 | 14 | 14 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Bay Front | Wisconsin | 3982 | 1 | 26 | 26 |
| Bay Front | Wisconsin | 3982 | 2 | 25 | 25 |
| Bay Front | Wisconsin | 3982 | 5 | 6 | 6 |
| Blount Street | Wisconsin | 3992 | 3 | 0 | 0 |
| Blount Street | Wisconsin | 3992 | 5 | | |
| Blount Street | Wisconsin | 3992 | 6 | 1 | 1 |
| Blount Street | Wisconsin | 3992 | 7 | 2 | 2 |
| Blount Street | Wisconsin | 3992 | 8 | 10 | 10 |
| Blount Street | Wisconsin | 3992 | 9 | 9 | 9 |
| Columbia | Wisconsin | 8023 | 1 | 677 | 677 |
| Columbia | Wisconsin | 8023 | 2 | 561 | 561 |
| Combined Locks Energy Center, LLC | Wisconsin | 55558 | B06 | 1 | 1 |
| Concord | Wisconsin | 7159 | **1 | 7 | 7 |
| Concord | Wisconsin | 7159 | **2 | 5 | 5 |
| Concord | Wisconsin | 7159 | **3 | 6 | 6 |
| Concord | Wisconsin | 7159 | **4 | 9 | 9 |
| Depere Energy Center | Wisconsin | 55029 | B01 | 12 | 12 |
| DTE Stoneman, LLC | Wisconsin | 4146 | B1 | 35 | 35 |
| DTE Stoneman, LLC | Wisconsin | 4146 | B2 | 35 | 35 |
| Edgewater (4050) | Wisconsin | 4050 | 3 | 22 | 22 |
| Edgewater (4050) | Wisconsin | 4050 | 4 | 282 | 282 |
| Edgewater (4050) | Wisconsin | 4050 | 5 | 401 | 401 |
| Elk Mound Generating Station | Wisconsin | 7863 | 1 | 2 | 2 |
| Elk Mound Generating Station | Wisconsin | 7863 | 2 | 3 | 3 |
| Elm Road Generating Station | Wisconsin | 56068 | 1 | 520 | 520 |
| Elm Road Generating Station | Wisconsin | 56068 | 2 | 410 | 410 |
| Fitchburg Generating Station | Wisconsin | 3991 | 1 | 1 | 1 |
| Fitchburg Generating Station | Wisconsin | 3991 | 2 | 1 | 1 |
| Fox Energy Company LLC | Wisconsin | 56031 | CTG-1 | 20 | 20 |
| Fox Energy Company LLC | Wisconsin | 56031 | CTG-2 | 19 | 19 |
| French Island | Wisconsin | 4005 | 3 | | |
| French Island | Wisconsin | 4005 | 4 | 1 | 1 |
| Genoa | Wisconsin | 4143 | 1 | 239 | 239 |
| Germantown Power Plant | Wisconsin | 6253 | **5 | 3 | 3 |
| Germantown Power Plant | Wisconsin | 6253 | P30 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P31 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P32 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P33 | 0 | 0 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Germantown Power Plant | Wisconsin | 6253 | P34 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P35 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P36 | 0 | 0 |
| Germantown Power Plant | Wisconsin | 6253 | P37 | 0 | 0 |
| Island Street Peaking Plant | Wisconsin | 55836 | 1A | 1 | 1 |
| Island Street Peaking Plant | Wisconsin | 55836 | 1B | 1 | 1 |
| J P Madgett | Wisconsin | 4271 | B1 | 339 | 339 |
| Manitowoc | Wisconsin | 4125 | 6 | | |
| Manitowoc | Wisconsin | 4125 | 7 | | |
| Manitowoc | Wisconsin | 4125 | 8 | 13 | 13 |
| Manitowoc | Wisconsin | 4125 | 9 | 27 | 27 |
| Marshfield Utilities Combustion Turbine | Wisconsin | 56480 | 1A | 1 | 1 |
| Marshfield Utilities Combustion Turbine | Wisconsin | 56480 | 1B | 1 | 1 |
| Neenah Energy Facility | Wisconsin | 55135 | CT01 | 11 | 11 |
| Neenah Energy Facility | Wisconsin | 55135 | CT02 | 11 | 11 |
| Nelson Dewey | Wisconsin | 4054 | 1 | 112 | 112 |
| Nelson Dewey | Wisconsin | 4054 | 2 | 117 | 117 |
| Paris | Wisconsin | 7270 | **1 | 9 | 9 |
| Paris | Wisconsin | 7270 | **2 | 8 | 8 |
| Paris | Wisconsin | 7270 | **3 | 9 | 9 |
| Paris | Wisconsin | 7270 | **4 | 9 | 9 |
| Pleasant Prairie | Wisconsin | 6170 | 1 | 596 | 596 |
| Pleasant Prairie | Wisconsin | 6170 | 2 | 621 | 621 |
| Port Washington Generating Station | Wisconsin | 4040 | 11 | 21 | 21 |
| Port Washington Generating Station | Wisconsin | 4040 | 12 | 20 | 20 |
| Port Washington Generating Station | Wisconsin | 4040 | 21 | 23 | 23 |
| Port Washington Generating Station | Wisconsin | 4040 | 22 | 23 | 23 |
| Pulliam | Wisconsin | 4072 | 5 | 13 | 13 |
| Pulliam | Wisconsin | 4072 | 6 | 23 | 23 |
| Pulliam | Wisconsin | 4072 | 7 | 47 | 47 |
| Pulliam | Wisconsin | 4072 | 8 | 92 | 92 |
| Pulliam | Wisconsin | 4072 | 32 | 9 | 9 |
| Riverside Energy Center | Wisconsin | 55641 | CT-01 | 16 | 16 |
| Riverside Energy Center | Wisconsin | 55641 | CT-02 | 16 | 16 |
| Rock River | Wisconsin | 4057 | 1 | | |
| Rock River | Wisconsin | 4057 | 2 | | |
| Rock River | Wisconsin | 4057 | CT3 | 1 | 1 |
| Rock River | Wisconsin | 4057 | CT5A | 1 | 1 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Rock River | Wisconsin | 4057 | CT5B | 1 | 1 |
| Rock River | Wisconsin | 4057 | CT6A | 0 | 0 |
| Rock River | Wisconsin | 4057 | CT6B | 0 | 0 |
| Rockgen Energy Center | Wisconsin | 55391 | CT-1 | 16 | 16 |
| Rockgen Energy Center | Wisconsin | 55391 | CT-2 | 12 | 12 |
| Rockgen Energy Center | Wisconsin | 55391 | CT-3 | 12 | 12 |
| Rothschild Biomass Cogeneration Facility | Wisconsin | 58124 | 1 | 50 | 50 |
| Sheboygan Falls Energy Facility | Wisconsin | 56166 | 1 | 7 | 7 |
| Sheboygan Falls Energy Facility | Wisconsin | 56166 | 2 | 6 | 6 |
| Sheepskin | Wisconsin | 4059 | CT1A | 1 | 1 |
| Sheepskin | Wisconsin | 4059 | CT1B | 1 | 1 |
| South Fond Du Lac | Wisconsin | 7203 | **CT1 | 2 | 2 |
| South Fond Du Lac | Wisconsin | 7203 | **CT2 | 1 | 1 |
| South Fond Du Lac | Wisconsin | 7203 | **CT3 | 2 | 2 |
| South Fond Du Lac | Wisconsin | 7203 | **CT4 | 2 | 2 |
| South Oak Creek | Wisconsin | 4041 | 5 | 260 | 260 |
| South Oak Creek | Wisconsin | 4041 | 6 | 250 | 250 |
| South Oak Creek | Wisconsin | 4041 | 7 | 248 | 248 |
| South Oak Creek | Wisconsin | 4041 | 8 | 305 | 305 |
| Valley (WEPCO) | Wisconsin | 4042 | 1 | 34 | 34 |
| Valley (WEPCO) | Wisconsin | 4042 | 2 | 33 | 33 |
| Valley (WEPCO) | Wisconsin | 4042 | 3 | 29 | 29 |
| Valley (WEPCO) | Wisconsin | 4042 | 4 | 33 | 33 |
| West Marinette | Wisconsin | 4076 | **33 | 10 | 10 |
| West Marinette | Wisconsin | 4076 | **34 | 7 | 7 |
| West Marinette | Wisconsin | 4076 | 31A | 1 | 1 |
| West Marinette | Wisconsin | 4076 | 31B | 1 | 1 |
| West Marinette | Wisconsin | 4076 | 32A | 1 | 1 |
| West Marinette | Wisconsin | 4076 | 32B | 1 | 1 |
| Weston | Wisconsin | 4078 | 1 | 23 | 23 |
| Weston | Wisconsin | 4078 | 2 | 43 | 43 |
| Weston | Wisconsin | 4078 | 3 | 303 | 303 |
| Weston | Wisconsin | 4078 | 4 | 442 | 442 |
| Weston | Wisconsin | 4078 | 32A | 1 | 1 |
| Weston | Wisconsin | 4078 | 32B | 1 | 1 |
| Wheaton Generating Plant | Wisconsin | 4014 | 1 | 5 | 5 |
| Wheaton Generating Plant | Wisconsin | 4014 | 2 | 7 | 7 |
| Wheaton Generating Plant | Wisconsin | 4014 | 3 | 5 | 5 |

| Plant Name | State | ORIS ID | Boiler ID | NOx OS Allocation 2017 (tons) | NOx OS Allocation 2018 and Beyond (tons) [1] |
|---|---|---|---|---|---|
| Wheaton Generating Plant | Wisconsin | 4014 | 4 | 4 | 4 |
| Wheaton Generating Plant | Wisconsin | 4014 | 5 | 1 | 1 |
| Wheaton Generating Plant | Wisconsin | 4014 | 6 | 1 | 1 |
| Whitewater Cogeneration Facility | Wisconsin | 55011 | 01 | 31 | 31 |

[1] 2017 unit level allocations are identical to 2018 and beyond unit level allocations except for Arkansas units as Arkansas has a different state budget for 2017 vs 2018 and beyond.

**Revised CSAPR Update Total 2021 Allocations with Supplemental Allowances and 2021 Assurance Levels (tons)**

| (A) State | (B) Final RCU 2021 Emission Budget | (C) Final CSAPR Update 2020 Emission Budget | (D) 2021 Supplemental Allowances | (E) Total 2021 Allocations with Supplemental Allowances | (F) Final RCU 2021 Variability Limit | (G) 2021 Assurance Level Increment | (H) 2021 Assurance Level |
|---|---|---|---|---|---|---|---|
| Illinois | 9,102 | 14,601 | 2,121 | 11,223 | 1,911 | 2,566 | 13,579 |
| Indiana | 13,051 | 23,303 | 3,953 | 17,004 | 2,741 | 4,783 | 20,575 |
| Kentucky | 15,300 | 21,115 | 2,242 | 17,542 | 3,213 | 2,713 | 21,226 |
| Louisiana | 14,818 | 18,639 | 1,473 | 16,291 | 3,112 | 1,782 | 19,712 |
| Maryland | 1,499 | 3,828 | 898 | 2,397 | 315 | 1,087 | 2,901 |
| Michigan | 12,727 | 17,023 | 1,657 | 14,384 | 2,673 | 2,005 | 17,405 |
| New Jersey | 1,253 | 2,062 | 312 | 1,565 | 263 | 378 | 1,894 |
| New York | 3,416 | 5,135 | 663 | 4,079 | 717 | 802 | 4,935 |
| Ohio | 9,690 | 19,522 | 3,791 | 13,481 | 2,035 | 4,587 | 16,312 |
| Pennsylvania | 8,379 | 17,952 | 3,692 | 12,071 | 1,760 | 4,467 | 14,606 |
| Virginia | 4,516 | 9,223 | 1,815 | 6,331 | 948 | 2,196 | 7,660 |
| West Virginia | 13,334 | 17,815 | 1,728 | 15,062 | 2,800 | 2,091 | 18,225 |

Sources and computations:

(B) RCU 2021 state budgets are from 40 CFR 97.1010(a), Table 1. Note that these amounts include the portions of the budgets set aside for new units.
(C) CSAPR Update 2020 state budgets are from 40 CFR 97.810(a). Note that these amounts include the portions of the budgets set aside for new units.
(D) 2021 supplemental allowances are computed as ( C - B ) * ( 59 / 153 ). See 40 CFR 97.1010(d).
(E) Total 2021 allocations are computed as B + D. Note that these amounts include the portions of the budgets set aside for new units.
(F) Final RCU 2021 variability limits are from 40 CFR 97.1010(b), Table 4. (The amounts are computed as 0.21 * B.)
(G) 2021 assurance level increments are computed as 1.21 * D. See 40 CFR 97.1006(c)(2)(iii).
(H) 2021 assurance levels are computed as B + F + G. See 40 CFR 97.1006(c)(2)(iii).

| State | Facility Na | Facility ID | Unit ID | Associated | Year | Operating | Sum of the | Gross Load | Steam Loa |
|---|---|---|---|---|---|---|---|---|---|
| KY | Big Sandy | 1353 | BSU1 | | 2017 | 1425 | 1417.15 | 225743.3 | |
| KY | Big Sandy | 1353 | BSU1 | | 2018 | 2431 | 2422.94 | 413803.3 | |
| KY | Big Sandy | 1353 | BSU1 | | 2019 | 3031 | 3027.07 | 615666.8 | |
| KY | Big Sandy | 1353 | BSU1 | | 2020 | 3046 | 3042.69 | 645542.1 | |
| KY | Big Sandy | 1353 | BSU1 | | 2021 | 2049 | 2043.12 | 315080.9 | |
| KY | Big Sandy | 1353 | BSU1 | | 2022 | 1688 | 1681.9 | 235213.8 | |
| KY | Big Sandy | 1353 | BSU1 | | 2023 | 2929 | 2921.53 | 516095.1 | |

| SO2 Mass | SO2 Rate ( | CO2 Mass | CO2 Rate ( | NOx Mass | NOx Rate ( | Heat Input | Primary Fuel Type | Secondary |
|---|---|---|---|---|---|---|---|---|
| 5.847 | 0.005 | 134940.6 | 0.059 | 183.24 | 0.1265 | 2270597 | Natural Gas | |
| 10.531 | 0.005 | 243042.2 | 0.059 | 325.075 | 0.1359 | 4089633 | Natural Gas | |
| 15.301 | 0.005 | 353125.2 | 0.059 | 503.812 | 0.1524 | 5942021 | Natural Gas | |
| 15.971 | 0.005 | 368598 | 0.059 | 518.548 | 0.1527 | 6202379 | Natural Gas | |
| 8.09 | 0.005 | 186702.5 | 0.059 | 235.122 | 0.1283 | 3141604 | Natural Gas | |
| 6.136 | 0.005 | 141605.2 | 0.059 | 174.973 | 0.1264 | 2382748 | Natural Gas | |
| 12.908 | 0.005 | 297905.6 | 0.059 | 400.655 | 0.1412 | 5012814 | Natural Gas | |

| Unit Type | SO2 Controls | NOx Controls |
|---|---|---|
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |
| Dry bottom wall-fired boiler | | Low NOx Burner Technology (Dry Bottom only)\|Overfire Air |

| PM Controls | Hg Controls | Program Code |
| --- | --- | --- |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG2, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG2, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG2, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG2, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG3, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG3, CSSO2G1 |
| Electrostatic Precipitator | | ARP, CSNOX, CSOSG2E, CSSO2G1 |

| Program C | Year | Account Number | Account N | Facility Na | Facility ID | Units Affe | Complianc | Total Allov |
|---|---|---|---|---|---|---|---|---|
| CSOSG2 | 2017 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 1045 | 1085 |
| CSOSG2 | 2018 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 1045 | 1299 |
| CSOSG2 | 2019 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 1045 | 684 |
| CSOSG2 | 2020 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 1045 | 821 |
| CSOSG3 | 2021 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 379 | 289 |
| CSOSG3 | 2022 | 001353FACLTY | Big Sandy | Big Sandy | 1353 | BSU1 | 279 | 238 |

| Emissions | Other Ded | Total Allov | Allowance | Excess Emi |
|---|---|---|---|---|
| 183 | | 183 | 902 | |
| 325 | | 325 | 974 | |
| 504 | | 504 | 180 | |
| 519 | | 519 | 302 | |
| 235 | | 235 | 54 | |
| 175 | | 175 | 63 | |

| Owner/Operator | State |
|---|---|
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |
| Kentucky Power Company (Operator)\|Kentucky Power Company (Owner) | KY |

## 7.5 Preferred Plan

The IRP Scorecard does not select a Preferred Plan (PP) on its own, rather it provides a way of systematically comparing how each of the portfolios perform across the four IRP objectives. Each resource portfolio considered in the 2022 IRP represents a trade-off between the objectives defined by Kentucky Power. The CETA portfolio, for example, provides the greatest level of seasonal reliability, but has the highest expected short-term costs to customers. Meanwhile, the ECR portfolio has the most positive local and sustainability impacts, but has low rankings in reliability, rate stability, and long-term cost. The purpose of the Scorecard is to provide Kentucky Power management with a tool that illustrates these trade-offs and enables the selection of the best path forward for Kentucky Power's customers and stakeholders.

After consideration of the portfolio needs and risks, Kentucky Power identified a PP that is informed by the scorecard results, scoring competitively across all scorecard elements and provides a "least regrets" portfolio for the near and mid-terms. The objective of the PP was to strike a balance of reliability, affordability, and sustainability for customers without overreliance on any one resource while also providing optionality to Kentucky Power for the type and timing of resources based on future RFP results. The PP includes a combination of supply- and demand-side resources to meet Kentucky Power's future customer needs. The portfolio maintains affordable and stable rates for Kentucky Power customers, is expected to maintain reliability across seasons, provides sufficient capacity to meet PJM obligations and allow for some margin of uncertainty in the future related to these obligations, and creates opportunities for local development all while significantly reducing greenhouse gas emissions. The rest of this section will review the detailed outputs of the PP and discuss its performance relative to the other portfolios considered as part of the 2022 IRP.

### 7.5.1 Details of the Preferred Plan

The Preferred Plan pre-selects the 480 MW frame CT build identified in the optimized portfolios along with the renewable and intermittent resource selections from the CC portfolio represented by 700 MW of new wind and 800 MW of new solar, along with 50MW of storage by 2037. The Preferred Plan also includes the extension of the Big Sandy gas unit to 2041. Short-Term Market Purchases (STMP) are utilized with up to 78 MW annually through 2026 and 407 MW in 2028 to fully satisfy near-term adequacy.

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On the demand side, the summer peak contribution from incremental demand-side resources is 3 MW in 2023, rising to a peak of 48 MW in 2034 before declining to 46 MW by 2037. Details of the annual capacity additions in the PP are displayed in Figure 80 and annual energy position in Figure 81 below.

| [illegible] | Gas CT | Gas CC | Solar (T1.T2) | Wind (T1.T2) | Li-Ion 4hr Battery Storage | Solar + Storage | Big Sandy Extension | Capacity Purchase | DSM Programs |
|---|---|---|---|---|---|---|---|---|---|
| [illegible] | | | | | | | | 73 | 3 |
| [illegible] | | | | | | | | 78 | 8 |
| [illegible] | | | | | | | | 78 | 14 |
| [illegible] | | | | 100 | | | | 78 | 24 |
| [illegible] | | | 250 | 100/100 | | | | | 32 |
| [illegible] | | | 150/300 | 100/100 | | | | 407 | 38 |
| [illegible] | 480 | | 100 | | | | | | 43 |
| [illegible] | | | | 100 | | | | | 47 |
| [illegible] | | | | 100 | | | 295 | | 47 |
| [illegible] | | | | | | | | | 48 |
| [illegible] | | | | | | | | | 48 |
| [illegible] | | | | | | | | | 48 |
| [illegible] | | | | | 50 | | | | 48 |
| [illegible] | | | | | | | | | 47 |
| [illegible] | | | | | | | | | 46 |
| [illegible] | 480 | 0 | 800 | 700 | 50 | 0 | 295 | | |

**Figure 80. Annual Capacity Additions in the 2022 IRP Preferred Plan**

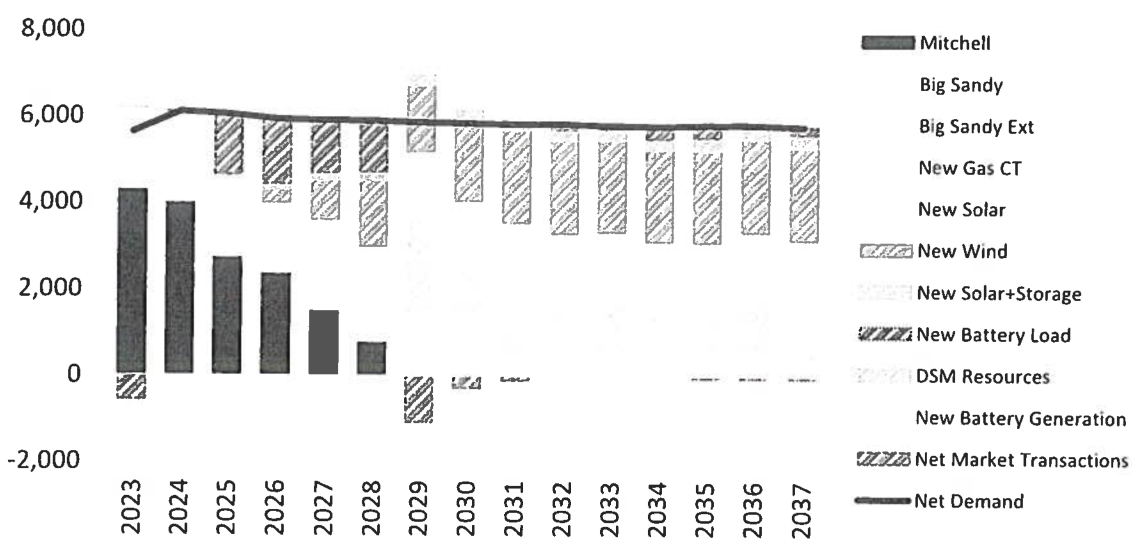


**Figure 81. Kentucky Power Annual Energy Position (GWh) under Preferred Plan**

Under the Preferred Plan, the Mitchell coal unit leaves the portfolio in 2028, while operations at the Big Sandy gas unit are extended to 2041. On the demand side, Kentucky Power projects approximately 48 MW of demand-side resources between 2023 and 2030. In addition to demand-side programs, Kentucky Power proposes to add 800 MW of new solar, 700 MW of new

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wind, and 50MW of storage by 2037. All of the solar and wind resources are added in the 2026-2031 time frame to take advantage of the production tax credit and contribute to accredited capacity replacement. The Preferred Plan also proposes to add 480 MW of new gas CT in 2029 as the Mitchell coal unit leaves the portfolio. The Preferred Plan relies on market capacity purchases through 2026 and again in 2028 to bridge shortfalls as Kentucky Power works to acquire firm resources.[48]

The Preferred Plan is informed by an analysis of the optimized portfolios discussed in section 7.3 to meet PJM minimum reserve margins given assumptions about resource availability and constraints on portfolio energy sales. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resource availability, their contribution to reserve margins, load growth, new environmental and tax policy, and existing unit performance. The Preferred Plan includes resources to meet the Company's current PJM capacity obligations while allowing for optionality if customers' capacity and energy needs requirements change. This includes a natural gas resource, currently identified as a natural gas combustion turbine in place of a combined cycle unit. The analyses of portfolios with NGCTs vs. NGCCs were similar in costs although the NGCT portfolio scored better in several non-cost scorecard metrics, including, in part, an increased capacity towards the Company's minimum PJM capacity obligation. The final decision to select a natural gas resource that is critical to the portfolio will be subject to results of an all-source RFP and analysis. Consequently, the Company will continue to evaluate its capacity position relative to these risks and may consider adding additional resources to the Plan in the future to ensure a capacity position in compliance with PJM's capacity reserve requirements. Furthermore, the Preferred Plan provides Kentucky Power flexibility and optionality with respect to uncertainty related to winter capacity needs. As described in section 7.3.2, a portfolio optimized to meet winter peak would add to the foundational gas and renewable resources already included in the Preferred Plan, providing the potential to integrate incremental storage resources to satisfy adequacy requirements.

[48] Depending on the results of the RFP, the Company may pursue different quantities or types of resources from those identified in the Preferred Plan.

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### 7.5.2 The Preferred Plan Best Achieves Kentucky Power's IRP Objectives

**Introduction**

For this IRP, seven portfolios were analyzed which informed the Company's identification of its Preferred Plan. The complete Scorecard with the Preferred Plan is shown below in Figure 82. A discussion of the Preferred Plan scorecard metrics follows.

| | Customer Affordability | | | | | Maintaining Reliability | | | Local Impacts & Sustainability | |
|---|---|---|---|---|---|---|---|---|---|---|
| Portfolio | Short Term: 5-yr Cost CAGR Reference Case | Long Term: 15-yr CPW Reference Case | Scenario Range: High Minus Low Scenario Range 15-yr CPW | Cost Risk: RR Increase in Reference Case (95th minus 50th Percentile) | Market Exposure: Net Sales as % of Portfolio Load Scenario Average | Planning Reserves: % Reserve Margin Scenario Average | Operational Flexibility: Dispatchable Capacity | Resource Diversity: Generation Mix (MWh) by Technology Type - Reference Case | Local Impacts: New Nameplate MW & Total CAPEX Installed Inside Service Territory | CO2 Emissions: Percent Reduction from 2005 Baseline - Reference Case |
| Reference Portfolio | 7.52 | 3,395 $62.1 | 438 $8.9 | 77.6 | 14% \| 30% | 11.3% \| -22.7% | 1,111 \| 775 |  | 893 \| 1,146 | 74% \| 90% |
| Reference – High Cost Portfolio | 8.53 | 3,435 $62.3 | 432 $8.7 | 72.2 | 10% \| 26% | 10.6% \| -23.1% | 1,111 \| 775 |  | 855 \| 1,134 | 74% \| 90% |
| CETA Portfolio | 9.16 | 3,504 $64.0 | 565 $11.6 | 87.1 | 31% \| 39% | 20.2% \| -19.9% | 1,111 \| 825 |  | 1,205 \| 1,511 | 74% \| 90% |
| ECR Portfolio | 8.21 | 3,605 $65.6 | 886 $15.1 | 95.8 | 28% \| 26% | 3.4% \| -37.4% | 1,111 \| 490 |  | 1,465 \| 1,942 | 74% \| 96% |
| NCR Portfolio | 7.91 | 3,517 $64.1 | 497 $13.3 | 37.9 | -25% \| -20% | 10.2% \| -20.8% | 1,111 \| 925 |  | 855 \| 1,067 | 74% \| 90% |
| CC Portfolio | 8.78 | 3,516 $64.6 | 430 $9.3 | 56.8 | 24% \| 21% | 10.7% \| -26.5% | 1,111 \| 763 |  | 993 \| 1,528 | 74% \| 86% |
| No Wind Portfolio | 7.65 | 3,755 $68.4 | 684 $12.6 | 48.9 | 5% \| -45% | 10.6% \| -37.1% | 1,111 \| 660 |  | 1,178 \| 2,088 | 74% \| 94% |
| Preferred Plan | 8.81 | 3,522 $64.8 | 501 $9.4 | 58.3 | 6% \| 0% | 14.6% \| -23.5% | 1,111 \| 825 |  | 1,055 \| 1,355 | 74% \| 90% |

**Figure 82. 2022 IRP Scorecard Preferred Plan Results**

Note - Levelized Rates and CPW metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers

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increased investment in more solar resources. After increases through 2028, the difference in rate impacts in future years of the Preferred Plan declines to approximately \$3.30/month through 2034.

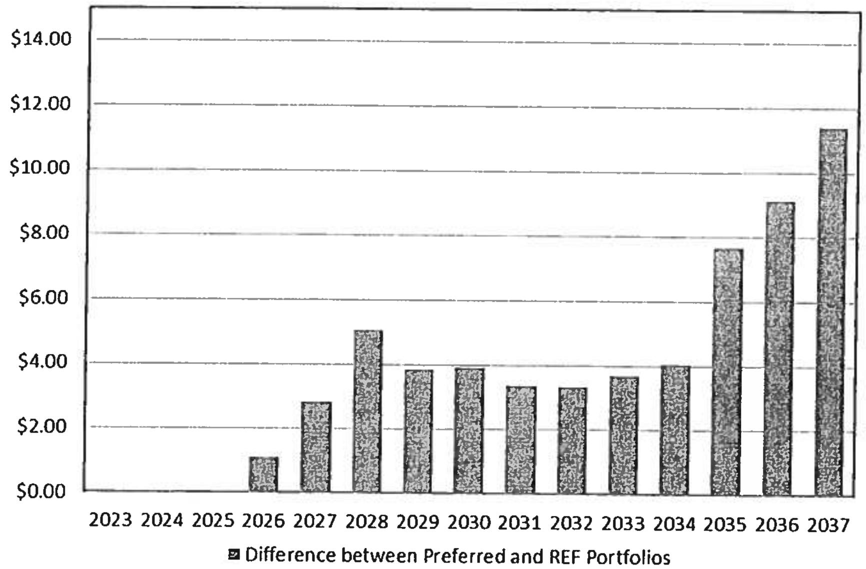


**Figure 83. Bill Impacts (\$/Month) of Preferred Plan Compared to Reference Portfolio**

### 7.5.4 Rate Impacts of the Preferred Plan

The average "real" rate per kWh expected to be paid by Kentucky Power customers from 2023 to 2037 that results directly from the costs and energy consumption impacts associated with the Preferred Plan is shown in Table 23 below. As previously stated, Kentucky Power does not expect to add any major new baseload generation during this period; however, renewable projects, new EE programs, and peaking unit additions will require investments and/or purchase obligations. On a real (2023) dollar basis as reflected in Table 23, this Preferred Plan is anticipated to result in relatively steady customer-estimated rates. These projected rates show Kentucky Power's projected success in mitigating the impact of carbon regulation on customer rates through its development of a well-diversified, renewable-centric portfolio.

KIUC
HEARING EXHIBIT 2

**Table 23. Approximate Rate Impacts of Preferred Plan**

| Year | Nominal ($/kWh) | Real ($2023/kWh) |
|---|---|---|
| 2023 | $0.165 | $0.165 |
| 2024 | $0.170 | $0.166 |
| 2025 | $0.171 | $0.164 |
| 2026 | $0.172 | $0.161 |
| 2027 | $0.178 | $0.163 |
| 2028 | $0.190 | $0.171 |
| 2029 | $0.196 | $0.174 |
| 2030 | $0.198 | $0.173 |
| 2031 | $0.196 | $0.168 |
| 2032 | $0.193 | $0.163 |
| 2033 | $0.192 | $0.158 |
| 2034 | $0.190 | $0.154 |
| 2035 | $0.191 | $0.152 |
| 2036 | $0.190 | $0.149 |
| 2037 | $0.196 | $0.150 |

* Note: The rate impacts presented in this table do not consider the prospect of increases in Kentucky Power's transmission and distribution-related costs over this period, as well as increases in base generation-related costs not uniquely incorporated into the planning/modeling process.

Kentucky Power Company
KPSC Case No. 2023-00092
AG-KIUC's First Set of Data Requests
Dated May 22, 2023

**DATA REQUEST**

**AG_KIUC 1_43** Kentucky Power's entitlement to Mitchell capacity runs through at least December 31, 2028 (even though its ownership extends beyond 2028). Did the modeling assume that replacement capacity for Mitchell would be needed beginning January 1, 2029? Please explain.

**RESPONSE**

The modeling assumed the replacement capacity would be needed for the PJM Planning Year 2028/2029 that begins June 1, 2028.

Witness: Thomas Haratym

**KIUC**
**HEARING EXHIBIT 3**

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

**DATA REQUEST**

**KPSC 1_39** Refer to the IRP, Volume A, Section 7.3.1, pages 155–161.
a. Explain why significant amounts of capacity purchases, 450 MW, are required in 2028.
b. Explain why the NGCC option was never selected in any of the scenarios in which the AURORA model was allowed to select any resource.

**RESPONSE**

a. Because the Mitchell Plant capacity would not be available for the entirety of the 2028/2029 PJM planning year, it was excluded from the portfolio for that PJM planning year. Thus, the Company would be short capacity and didn't anticipate it would be able to acquire adequate long-term resources to fill the need in this time period, and therefore capacity purchases would be necessary.

b. For this IRP, the NGCC was not economic versus the alternative resources within the model. This is a result of a combination of factors including capital costs, O&M costs, emissions costs and tax credits.

Witness: Thomas Haratym (Charles River and Associates)

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Capacity Purchases - Preferred Plan, REF Scenario

| Year | Capacity Purchases ($Nominal) |
|---|---|
| 2023 | 895,042 |
| 2024 | 1,567,452 |
| 2025 | 2,952,814 |
| 2026 | 2,812,177 |
| 2027 | 0 |
| 2028 | 15,668,228 |
| 2029 | 0 |
| 2030 | 0 |
| 2031 | 0 |
| 2032 | 0 |
| 2033 | 0 |
| 2034 | 0 |
| 2035 | 0 |
| 2036 | 0 |
| 2037 | 0 |
| 2038 | 0 |
| 2039 | 0 |
| 2040 | 0 |
| 2041 | 0 |
| 2042 | 0 |

3

**DATA REQUEST**

**KPSC 3_2** Refer to the Direct Testimony of Lane Kollen (Kollen Direct Testimony), page 5. Kentucky Power estimated that its undivided 50 percent interest in Mitchell has a $343.1 million net book value as of December 31, 2028. Refer also to the Direct Testimony of Timothy Kerns (Kerns Direct Testimony), page 7. Kentucky Power states that its undivided 50 percent interest in Mitchell will terminate in 2028.

a. Provide an updated book value and market value of Kentucky Power's undivided 50 percent interest in Mitchell.

b. Explain how Kentucky Power plans to terminate its undivided 50 percent interest in Mitchell. Include in the response if it plans to sell or transfer its interest to Wheeling Power Company, another AEP affiliate, or a non-AEP affiliated entity.

c. If the Commission were to deny Kentucky Power's request to sell/transfer/terminate its undivided 50 percent interest of the Mitchell units, explain how Kentucky Power would address selling/transferring/terminating its undivided 50 percent interest without Commission approval.

**RESPONSE**

a. Please see KPCO_R_KPSC_3_2_Attachment1 for the net book value of Kentucky Power's undivided 50 percent interest in Mitchell at 3/31/2024.

b. There are potentially several ways in which Kentucky Power could comply with the Commission's directive to terminate its interest in the Mitchell generating plant ("Mitchell"). As a threshold matter, the Company notes that in its May 3, 2022 Order in Case No. 2021-00421, the Commission ordered that December 31, 2028 is the date when Kentucky Power's interest in Mitchell must terminate. That order was the logical outcome of the July 15, 2021 Order in Case No. 2021-00004, denying Kentucky Power authority to construct the ELG environmental projects at Mitchell. In the context of that order, disposition of Kentucky Power's property interest in the Mitchell Plant, as the question implies, is not the only reasonable way to interpret the term "terminate." A reasonable interpretation of the term "terminate" is that, pursuant to the Commission's Order, Kentucky Power is not authorized contribute towards the capital investments necessary to operate the Mitchell plant to serve customers after December 31, 2028, and therefore Kentucky Power will no longer use its interest in the Mitchell Plant to serve customers after that date. Such an interpretation would be consistent with the fact that, as

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a result of the Commission's July 15, 2021 Order in Case No. 2021-00004, Kentucky Power has not invested in the ELG equipment that would otherwise permit Kentucky Power to use the plant after the December 31, 2028 ELG deadline. It is also consistent with Kentucky Power's previously disclosed approach to investing in the Mitchell Plant, under which it has been ratably investing in only that portion of equipment used for pre-December 31, 2028 operations so as to reduce rate impacts on customers to the extent possible prior to December 31, 2028.

In addition, the July 15, 2021 Order in Case No. 2021-00004 also offers Kentucky Power an ability to reapply to perform ELG work not currently authorized if Kentucky Power provides notice to the Commission and undertakes such construction with the Commission's approval. In April 2024, the EPA issued revised ELG final rules which require installation of zero liquid discharge technology for Flue Gas Desulfurization (FGD) wastewater by December 31, 2029, with certain exceptions if the plant commits to retiring by December 31, 2034. Kentucky Power is currently considering the potential impact of the revised ELG rules on Mitchell and which among the various approaches would be in the best interests of Kentucky customers in forming a future generation portfolio, which will also need to take into account the 2023 RFP results and feedback on the 2022 IRP case currently pending before the Commission.

Regarding a sale of the Company's undivided 50 percent interest in Mitchell, any such sale would require the approval of this Commission. KRS 278.218. In addition, regarding any potential sale of Kentucky Power's interests in Mitchell to Wheeling Power, the Company notes both:

1. The statement in the Commission's May 3, 2022 Order in Case No. 2021-00421 that the Commission expects that if Kentucky Power's Mitchell Plant interest is sold to Wheeling Power when both entities are affiliates, then the sale shall be priced at the greater of net book value or market value, with necessary adjustments, and is subject to Commission approval; and

2. The West Virginia Public Service Commission's July 1, 2022 Order in Case No. 2021-0810-E-PC that Wheeling Power must seek approval from the West Virginia Public Service Commission prior to purchasing Kentucky Power's interest in Mitchell, and that the West Virginia will not authorize an unreasonable purchase price above scrap value, stating any higher amount would reflect value that should be solely reserved for Wheeling Power's customers who paid for the ELG upgrades but for which the Mitchell Plant would have been obligated to retire effective December 31, 2028.

Thus, absent a change in position by either or both commissions, the Company does not currently believe a sale of Kentucky Power's interest in Mitchell to Wheeling Power is feasible. Nor, for similar reasons, does the Company believe a sale of Kentucky Power's interest in Mitchell to an affiliate or a third party is feasible absent Kentucky Power owning ELG and other assets co-equally with Wheeling Power.

c. See the answer to KPSC 3-2b above. In addition, the Company currently understands that based on the Commission's orders reference above and KRS 278.218 more generally, Kentucky Power may not sell or transfer its undivided 50 percent interest in the Mitchell Plant without Commission approval.

Witness: Brian K. West

Prepared by: Counsel (subpart b)

| company | major_location | asset_location | depr_group | utility_account | month | book_cost | allocated_reserve | net_book_value |
|---|---|---|---|---|---|---|---|---|
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 310 Mitchell Non-Depr | 31000 - Land - Coal Fired | 03/2024 | 3,098,594.25 | - | 3,098,594.25 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 311 Mitchell Plant | 31100 - Structures, Improvemnt-Coal | 03/2024 | 57,591,386.12 | 29,774,731.02 | 27,816,655.10 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 312 Mitchell Plant | 31200 - Boiler Plant Equip-Coal | 03/2024 | 885,016,658.73 | 434,768,340.15 | 450,248,318.58 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell SCR Catalyst : KPCo/WPCo : 8500SCR | KEPCo 101/6 312 Mitchell Plant SCR | 31200 - Boiler Plant Equip-Coal | 03/2024 | 9,345,062.82 | 8,914,274.01 | 430,788.81 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 314 Mitchell Plant | 31400 - Turbogenerator Units-Coal | 03/2024 | 56,929,807.96 | 36,958,919.12 | 19,970,888.84 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 315 Mitchell Plant | 31500 - Accessory Elect Equip-Coal | 03/2024 | 26,363,620.75 | 14,382,290.87 | 11,981,329.88 |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 316 Mitchell Plant | 31600 - Misc Pwr Plant Equip-Coal | 03/2024 | 9,847,534.01 | 5,274,913.27 | 4,572,620.74 |
| Kentucky Power - Gen | Mitchell Generating Plant | ARO#1 Connor Ash Pond, Mitchell Plant - WV : KPCo/OPCo : 8500ARO2 | KEPCo 101/6 317 ASH1 Conner Ash Pd | 31700 - ARO Steam Production Plant | 03/2024 | (1,820,881.13) | 385,025.08 | (2,205,906.21) |
| Kentucky Power - Gen | Mitchell Generating Plant | ARO#1 Mitchell Ash Pond - WV : KPCo/WPCo : 8500ARO | KEPCo 101/6 317 ASH1 Mitchell Ash | 31700 - ARO Steam Production Plant | 03/2024 | (102,069.69) | 13,611.40 | (115,681.09) |
| Kentucky Power - Gen | Mitchell Generating Plant | ARO#2 Mitchell Landfill - WV : KPCo/WPCo : 8500ARO | KEPCo 101/6 317 ASH2 Mitchell Ldfl | 31700 - ARO Steam Production Plant | 03/2024 | 3,596,017.97 | 995,609.39 | 2,600,408.58 |
| Kentucky Power - Gen | Mitchell Generating Plant | ARO#3 Mitchell Landfill - WV : KPCo/WPCo : 8500ARO | KEPCo 101/6 317 ASH3 Mitchell Ldfl | 31700 - ARO Steam Production Plant | 03/2024 | 830,641.01 | 1,232,248.82 | (401,607.81) |
| Kentucky Power - Gen | Mitchell Generating Plant | Mitchell Generating Plant Units 1&2 : KPCo/WPCo : 8500 | KEPCo 101/6 317 Mitchell Asbestos | 31700 - ARO Steam Production Plant | 03/2024 | 2,191,057.04 | 1,420,537.60 | 770,519.44 |
| | | | | | | 1,052,887,429.84 | 534,120,500.73 | 518,766,929.11 |

***Includes land and ARO Asset.*

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| FOM (Nominal $) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 2,961,936 | 2,153,066 | 1,909,915 | 1,970,164 | 2,777,389 | 1,915,158 | 1,934,243 | 1,954,281 | 1,979,417 | 2,015,835 | 2,053,491 | 2,091,924 | 2,131,183 | 2,171,741 | 2,213,367 | 2,255,783 | 2,299,507 | 2,344,473 | 976,864 | - |
| Mitchell (WV) 1 | 4,319,925 | 7,253,529 | 6,540,510 | 7,017,575 | 6,880,400 | 6,368,157 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mitchell (WV) 2 | 6,389,588 | 7,057,065 | 7,490,203 | 6,525,736 | 7,003,792 | 7,310,920 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Starting Rate Base (Nominal $) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 105,324,742 | 102,058,439 | 96,334,839 | 90,900,795 | 86,452,142 | 80,850,896 | 75,266,327 | 69,661,754 | 64,049,823 | 60,568,887 | 54,758,962 | 48,964,492 | 43,185,802 | 37,423,225 | 31,677,299 | 25,948,459 | 20,237,032 | 17,920,992 | 18,640,219 | 19,041,221 |
| Mitchell (WV) 1 | 258,737,593 | 268,721,438 | 256,882,413 | 245,103,305 | 235,838,177 | 224,459,227 | 213,867,298 | 198,714,009 | 183,560,720 | 168,407,431 | 153,254,142 | 138,100,853 | 122,947,564 | 107,794,275 | 92,640,986 | 77,487,697 | 62,334,408 | 47,181,119 | 46,049,439 | 46,049,439 |
| Mitchell (WV) 2 | 258,737,593 | 264,550,652 | 255,869,191 | 245,473,165 | 236,078,768 | 225,089,456 | 212,554,999 | 197,401,710 | 182,248,421 | 167,095,132 | 151,941,843 | 136,788,554 | 121,635,265 | 106,481,976 | 91,328,687 | 76,175,398 | 61,022,109 | 45,868,820 | 44,737,140 | 44,737,140 |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Ongoing CapEx (Nominal $) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 3,239,267 | 700,762 | 1,001,913 | 2,027,484 | 825,387 | 841,814 | 820,177 | 811,768 | 3,274,824 | 858,522 | 874,559 | 890,927 | 907,647 | 924,921 | 942,649 | 960,713 | 979,335 | 998,485 | 416,035 | - |
| Mitchell (WV) 1 | 26,031,777 | 3,463,093 | 3,520,753 | 6,135,995 | 3,928,488 | 4,742,409 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mitchell (WV) 2 | 21,712,550 | 6,762,450 | 4,963,915 | 6,001,285 | 4,334,039 | 2,722,778 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Depreciation (Nominal $) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 6,502,222 | 6,417,605 | 6,427,643 | 6,461,829 | 6,421,759 | 6,422,306 | 6,421,585 | 6,421,305 | 6,746,588 | 6,666,045 | 6,666,579 | 6,667,125 | 6,667,682 | 6,668,258 | 6,668,849 | 6,669,451 | 3,292,632 | 276,464 | 13,868 | - |
| Base Unit | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 6,394,246 | 3,016,806 | - | - | - |
| Ongoing CapEx | 107,976 | 23,359 | 33,397 | 67,583 | 27,513 | 28,060 | 27,339 | 27,059 | 109,161 | 28,617 | 29,152 | 29,698 | 30,255 | 30,831 | 31,422 | 32,024 | 32,644 | 33,283 | 13,868 | - |
| Extension | - | - | - | - | - | - | - | - | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | 243,181 | - | - |
| Mitchell (WV) 1 | 16,021,015 | 15,268,725 | 15,270,647 | 15,357,822 | 15,284,239 | 15,311,369 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 1,131,680 | - | - |
| Base Unit | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 1,131,680 | - | - |
| Ongoing CapEx | 867,726 | 115,436 | 117,358 | 204,533 | 130,950 | 158,080 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mitchell (WV) 2 | 15,877,041 | 15,378,704 | 15,318,753 | 15,353,332 | 15,297,757 | 15,244,048 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 1,131,680 | - | - |
| Base Unit | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 15,153,289 | 1,131,680 | - | - |
| Ongoing CapEx | 723,752 | 225,415 | 165,464 | 200,043 | 144,468 | 90,759 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Base Unit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ongoing CapEx | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Base Unit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ongoing CapEx | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Base Unit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ongoing CapEx | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Change in Deferred Tax Liability (Nominal $) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 3,349 | 6,757 | 8,313 | 14,307 | 4,874 | 4,077 | 3,164 | 2,395 | 9,172 | 2,402 | 2,450 | 2,493 | 2,542 | 2,588 | 2,640 | 2,688 | 2,743 | 2,794 | 1,165 | - |
| Mitchell (WV) 1 | 26,917 | 33,393 | 29,214 | 43,300 | 21,199 | 22,968 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mitchell (WV) 2 | 22,451 | 65,207 | 41,188 | 42,350 | 25,594 | 13,187 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Ending Rate Base ($ Nominal) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 102,058,439 | 96,334,839 | 90,900,795 | 86,452,142 | 80,850,896 | 75,266,327 | 69,661,754 | 64,049,823 | 60,568,887 | 54,758,962 | 48,964,492 | 43,185,802 | 37,423,225 | 31,677,299 | 25,948,459 | 20,237,032 | 17,920,992 | 18,640,219 | 19,041,221 | 19,041,221 |
| Mitchell (WV) 1 | 268,721,438 | 256,882,413 | 245,103,305 | 235,838,177 | 224,459,227 | 213,867,298 | 198,714,009 | 183,560,720 | 168,407,431 | 153,254,142 | 138,100,853 | 122,947,564 | 107,794,275 | 92,640,986 | 77,487,697 | 62,334,408 | 47,181,119 | 46,049,439 | 46,049,439 | 46,049,439 |
| Mitchell (WV) 2 | 264,550,652 | 255,869,191 | 245,473,165 | 236,078,768 | 225,089,456 | 212,554,999 | 197,401,710 | 182,248,421 | 167,095,132 | 151,941,843 | 136,788,554 | 121,635,265 | 106,481,976 | 91,328,687 | 76,175,398 | 61,022,109 | 45,868,820 | 44,737,140 | 44,737,140 | 44,737,140 |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Capital Charge ($ Nominal) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Big Sandy 1 | 6,324,467 | 5,969,780 | 5,633,038 | 5,357,359 | 5,010,255 | 4,664,184 | 4,316,874 | 3,969,108 | 3,753,358 | 3,393,162 | 3,034,284 | 2,676,184 | 2,319,082 | 1,963,013 | 1,608,002 | 1,254,070 | 1,110,547 | 1,155,117 | 1,179,967 | 1,179,967 |
| Mitchell (WV) 1 | 16,652,418 | 15,918,764 | 15,188,824 | 14,614,673 | 13,909,530 | 13,253,158 | 12,314,122 | 11,375,087 | 10,436,052 | 9,497,017 | 8,557,981 | 7,618,946 | 6,679,911 | 5,740,876 | 4,801,841 | 3,862,805 | 2,923,770 | 2,853,641 | 2,853,641 | 2,853,641 |
| Mitchell (WV) 2 | 16,393,958 | 15,855,976 | 15,211,744 | 14,629,582 | 13,948,584 | 13,171,836 | 12,232,800 | 11,293,765 | 10,354,730 | 9,415,695 | 8,476,659 | 7,537,624 | 6,598,589 | 5,659,554 | 4,720,519 | 3,781,483 | 2,842,448 | 2,772,319 | 2,772,319 | 2,772,319 |
| Rockport 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rockport 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spicewood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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KPCO_R_AG_KIUC_1_23_Attachment1.xlsx

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Xerox® AltaLink® C8070 MFP

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**PJM Solar and 4-Hr Battery Storage Peak Credit Assumptions*****

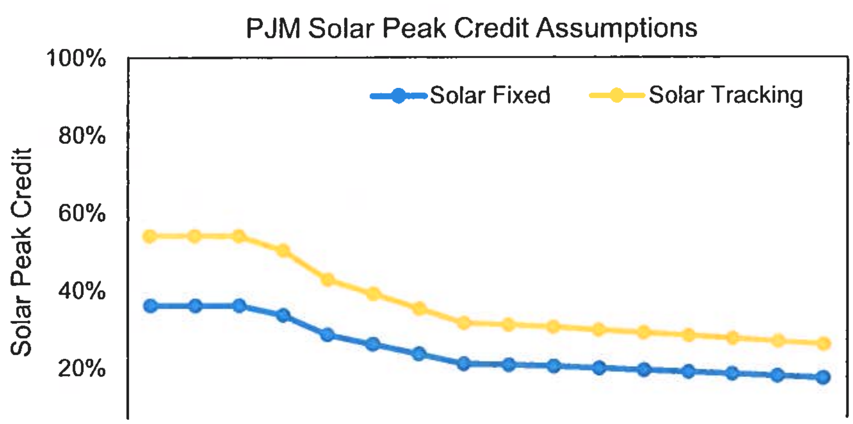
Capacity Contribution? Check the eFORd assumptions

| | Solar Fixed | Solar Tracking | Onshore Wind | Offshore Wind | 4-Hour Storage |
|---|---|---|---|---|---|
| 2022 | 36% | 54% | 16% | 37% | 82% |
| 2023 | 36% | 54% | 16% | 37% | 82% |
| 2024 | 36% | 54% | 16% | 37% | 82% |
| 2025 | 33% | 50% | 14% | 37% | 82% |
| 2026 | 28% | 43% | 13% | 37% | 82% |
| 2027 | 26% | 39% | 13% | 37% | 82% |
| 2028 | 23% | 35% | 12% | 35% | 82% |
| 2029 | 21% | 31% | 12% | 34% | 82% |
| 2030 | 21% | 31% | 11% | 32% | 79% |
| 2031 | 20% | 30% | 11% | 30% | 77% |
| 2032 | 20% | 30% | 11% | 30% | 74% |
| 2033 | 19% | 29% | 11% | 30% | 71% |
| 2034 | 19% | 28% | 11% | 29% | 69% |
| 2035 | 18% | 27% | 11% | 26% | 69% |
| 2036 | 18% | 27% | 11% | 26% | 68% |
| 2037 | 17% | 26% | 11% | 24% | 66% |
| 2038 | 17% | 25% | 11% | 24% | 66% |
| 2039 | 16% | 24% | 11% | 24% | 65% |
| 2040 | 15% | 23% | 11% | 23% | 65% |
| 2041 | 15% | 22% | 11% | 23% | 63% |
| 2042 | 14% | 22% | 11% | 23% | 63% |

* Reflects the ELCC Results from PJM's report, delivery year 2024/2025

** Solar ELCC reflects a weighted average estimate of both Solar Fixed and Solar Tracking

*** Assumed ELCC values reflect preliminary capacity expansion in PJM region and are subject t




**KIUC**
**HEARING EXHIBIT 4**

*ELCC Class Ratings for 2024/2025*

| ELCC Class | 2024/2025 |
|---|---|
| Onshore Wind | 21% |
| Offshore Wind | 47% |
| Solar Fixed Panel | 33% |
| Solar Tracking Panel | 50% |
| 4-hr Storage | 92% |
| 6-hr Storage | 100% |
| 8-hr Storage | 100% |
| 10-hr Storage | 100% |
| Solar Hybrid Open Loop - Storage Component | 75% |
| Solar Hybrid Closed Loop - Storage Component | 68% |
| Hydro Intermittent | 36% |
| Landfill Gas Intermittent | 61% |
| Hydro with Non-Pumped Storage* | 95% |

* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

# ELCC Class Ratings for the 2025/2026 Base Residual Auction

The following table provides the ELCC Class Ratings applicable to the 2025/2026 Base Residual Auction (BRA) as calculated under the methodology approved by FERC on January 30th, 2024 in Docket No. ER24-99.

| | 2025/2026 BRA ELCC Class Ratings |
|---|---|
| Onshore Wind | 35% |
| Offshore Wind | 60% |
| Fixed-Tilt Solar | 9% |
| Tracking Solar | 14% |
| Landfill Intermittent | 54% |
| Hydro Intermittent | 37% |
| 4-hr Storage | 59% |
| 6-hr Storage | 67% |
| 8-hr Storage | 68% |
| 10-hr Storage | 78% |
| Demand Resource | 76% |
| Nuclear | 95% |
| Coal | 84% |
| Gas Combined Cycle | 79% |
| Gas Combustion Turbine | 62% |
| Gas Combustion Turbine Dual Fuel | 79% |
| Diesel Utility | 92% |
| Steam | 75% |

- Pursuant to RAA Schedule 9.2, sections C(2) and D(1)(b): No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics. In these instances, the Accredited UCAP is based on a resource-specific ELCC analysis.
- For the 2025/2026 Delivery Year, PJM determined that the members of the Gas Combined Cycle Dual Fuel Class are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics. This is due to the Gas Combined Cycle Dual Fuel Class having very few members (less than 10 units) following the dual fuel attestation process for the 2025/26 BRA and there being a large disparity in the observed historical performance during hours of risk across the members of this class. Therefore, no ELCC Class Rating will be determined for the Gas Combined Cycle Dual Fuel Class for the 2025/2026 Delivery Year.

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

**DATA REQUEST**

**KPSC 1_38** Refer to the IRP, Volume A, Section 7.3.1, pages 159. Explain why the CC Portfolio added only 418 MW of NGCC.

**RESPONSE**

The CC Portfolio included a single 1x1, 418MW resource forced in 2029 to replace the optimized selection of 480MW of CTs in the Reference Portfolio. This was the closest available option in terms of capacity of modeled natural gas resources to evaluate.

Witness: Thomas Haratym (Charles River and Associates)

**KIUC**
**HEARING EXHIBIT 5**

**DATA REQUEST**

**AG_KIUC 1_24** In the Company's preferred plan, "the Big Sandy steam gas unit operates for an additional 10 years through mid-2041 . . . 800 MW of new solar and 700 MW of new wind by 2037 . . . 480 MW of new gas CT units in 2029 . . . 70-80 MW of short- term capacity purchases are made through 2026 and 407 MW in 2028 to bridge between the retirement of Mitchell and the addition of gas CT units . . . [and] 50 MW of 4-hour lithium-ion battery storage is added in 2035." (IRP report at 15). In comparison, the Company's "CC portfolio adds 418MW of 1x1 Combined Cycle, 700MW of wind, 800MW of solar, and 50MW of storage by 2037. This portfolio also includes the extension of operations for the Big Sandy gas unit until 2041. Short-Term Market Purchases (STMP) are utilized with up to 78 MW annually through 2026 and 407 MW in 2028 to fully satisfy near-term adequacy. (IRP report at 159).

a.Confirm that the only difference in the CC portfolio compared to the Company's preferred plan is the substitution of 418 mW of NGCC capacity for the 480 mW of NGCT capacity and that all other resources are the same between the CC portfolio and the Company's preferred plan. If this is not correct, then provide a corrected statement.

b.The Company states that "The CC portfolio was modeled following Stakeholder feedback and included the same assumptions as the Reference portfolio. In this portfolio, a CC was assumed to be built in 2029 in place of the CT from the Reference portfolio, and optimization was performed around this assumption." Describe how the Company performed this "optimization." Identify all constraints introduced in the CC portfolio, such as designated/forced renewables and storage resource selections, compared to the optimization modeling and resource selections utilized to develop the Company's preferred plan.

c. Explain why there is no reduction in the new solar, wind, and storage resources in the CC portfolio compared to the Company's preferred plan.

**RESPONSE**

a) Confirmed.

b) To model the CC Portfolio, the Company used the same assumptions as the Reference Case with the only exception that the CC resource was forced in as a resource in 2029.

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The model was run to select the balance of optimized resources to meet the Company's capacity obligation.

c) Please see response to KPSC_1_45 for a description of how the Company identified the Preferred Plan. The Preferred Plan incorporates elements of two optimized portfolios that included the renewable and storage resources selected in the CC portfolio.

Witness: Gregory J. Soller

Witness: Thomas Haratym

3

**DATA REQUEST**

**KPSC 1_45** Refer to the IRP, Volume A, Section 7.5.1, Figures 80–81, pages 173–175.

a. Provide a detailed comparison of the Combined Cycle (CC) Portfolio and the Preferred Plan.

b. Explain in greater detail how the Preferred Plan was obtained by changing the CC Portfolio.

c. Kentucky Power stated the Preferred Plan is based on an uncertain future that could impact the company's capacity position, including uncertainty around intermittent resource availability and the intermittent resources' contribution to reserve margins. Explain the logic of how a Preferred Plan containing 1,500 MW of new intermittent capacity, a new 480 MW NGCT, and the extended life of the 295 MW Big Sandy unit provides sufficient capacity to meet both summer and winter reserve margin obligations.

**RESPONSE**

a. The Preferred Plan (PP) includes the same resources as the CC Portfolio except that the CC resource was swapped for the CT resource that was consistently selected as part of the optimized portfolio analysis.

Comparing the Scorecard metrics of the Portfolios, the PP scores more favorably in several metrics while scoring very similarly in the 5 year CAGR and 15 year CPW metrics. More specifically, the PP, with the inclusion of the CTs results in improved reserve margin metrics, improved Operational Flexibility metric and a 5 year CAGR metric that was within 0.34% of the CC Portfolio and a 15 year CPW metric that was within 0.17% of the CC Portfolio.

b. The Preferred Plan was informed by the different Least-Cost Portfolios modeled and includes a diverse set of dispatchable and renewable generation resources.

The Preferred Plan scored competitively to the other Portfolios developed through the IRP process and modeling in Aurora. The Scorecard illustrates across multiple objectives and metrics, the competitiveness of the PP relative to all Portfolios including the CC Portfolio. The development of the IRP Objectives and Metrics along with portfolios to analyze was developed with key input from our IRP Stakeholders throughout the process.

The Company identified the Preferred Plan to include the renewable resources selected in the CC Portfolio while replacing the 418MW CC with 480MW of CT. This change was supported from the insights learned from the other optimized portfolios where the model identified capacity resources to fill the Company's PJM capacity obligation. The CT resource was included in the PP based on the analysis of the different least-cost portfolios that selected the CT as part of the modeled portfolios while also including a mix of additional renewable resources. In the near-term through 2029 specifically, the portfolio selection of renewable resources between the Reference, CETA, ECR, NCR and CC Portfolios were consistent with some small variations in the selection of wind or solar resources.

The No Wind and Winter Portfolios informed the process through a reliance on more solar and storage resources to fill capacity needs. In particular, the No Wind Portfolio modeled in response to Stakeholder feedback, identified a strong reliance on solar resources to provide a balance of energy and capacity value to fill the gap from wind resources selected in the other least cost portfolios. The No Wind Portfolio also selected the CT resource as part of its least cost solution. The Winter Portfolio analysis informed the process through primarily a swap of solar resources with storage resources in the early years through 2029. Wind resources were relied on as well with an increase in these resources over the Reference Portfolio through 2029.

As evident in the scorecard metrics and the relative competitiveness of the portfolios, the inclusion of the 480MW CT resource in place of the 418MW CC resource provides additional summer reserve margin of 14.7% relative to the Company's minimum PJM Obligation of 8.94%. The additional capacity length in the PP also serves to bolster the Company's reserve margin relative to a Winter Peak resulting in a 4% improvement on its net capacity position relative to a Kentucky Power specific load requirement over the CC Portfolio. The PP Operational Flexibility metric is also improved over the CC Portfolio as a result of the increased capacity amounts from the CT over the CC.

From a cost perspective, the Preferred Plan scored very similarly to the CC Portfolio with a 5 year CAGR metric that was within 0.34% of the CC Portfolio and a 15 year CPW that was within 0.17% of the CC Portfolio. While the Reference Portfolio identified the least cost plan, it included an amount of wind resources that were considered a risk in the long term plan supported by customer feedback and would be subject to additional reviews in future IRPs.

The PP provides Kentucky Power with a path forward and has identified the need for an all source RFP to examine in more detail the resource options available and how those resource characteristics will influence Kentucky Power's cost to serve its customers.

c. The PP is developed recognizing the capacity accreditation that PJM confers to each resource type. Therefore, the PP, which includes 1,500 MW of renewable generation, 480 MW of NGCT, 295 MW of Big Sandy, and other capacity resources does satisfy Kentucky's PJM capacity obligation of 8.94% as an FRR entity. The PP affords the Company optionality to meet its PJM capacity obligations as an FRR entity which are currently set to the Company's PJM coincident summer peak. The Company does not yet have a specific PJM winter capacity reserve margin obligation, but anticipates that PJM will establish a winter requirement in the future. Consequently, the Company evaluated a potential Winter requirement portfolio. The PP includes renewable resources was identified in all portfolio modeling to be part of a least-cost plan to meet the Company's current obligations. Should the Company's PJM capacity obligation transition to a seasonal construct that would include the Company's winter peak in some form, the PP includes resources complimentary to the Winter Portfolio analysis such that storage resources selected as part of the optimized set of resources in the Winter Portfolio could be added without significant conflicts to the other optimized selection of resources.

Witness: Gregory J. Soller

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