Thin Section Photomicrographs
with
Descriptions

PLATE 1 A-B

THIN SECTION PHOTOMICROGRAPHS

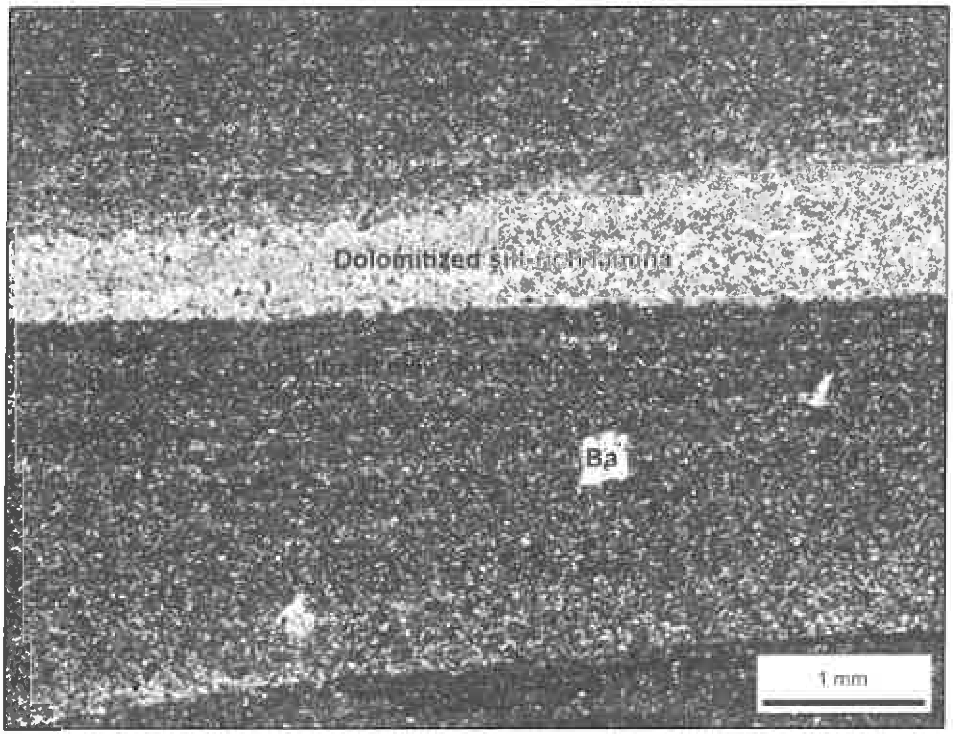
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 6782.0

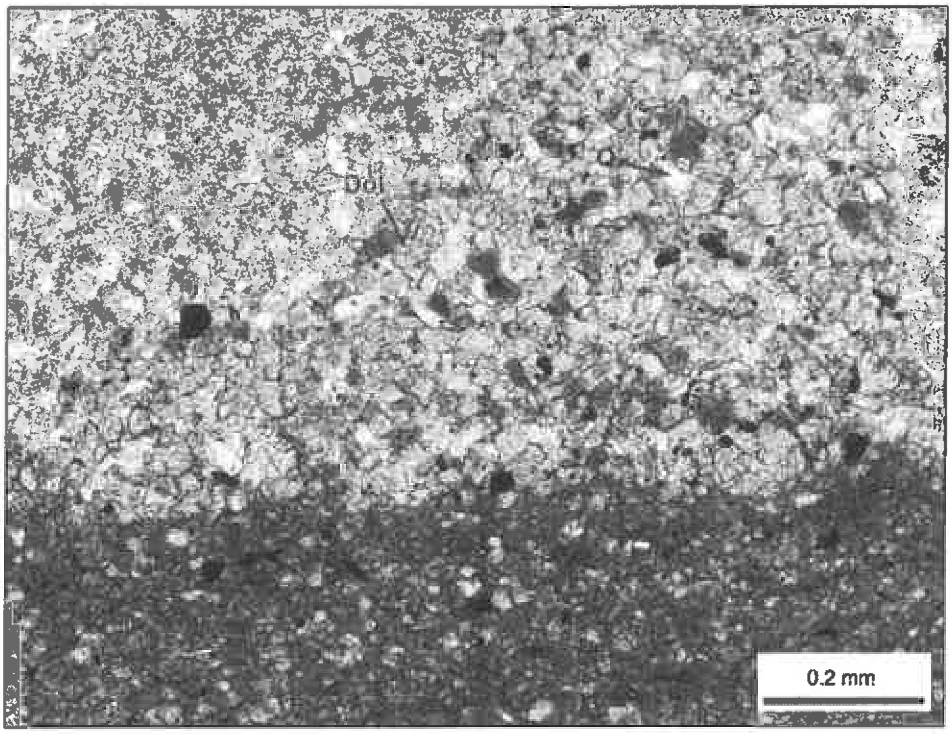
Lithology: Dolostone (dolomitized silty claystone)
Foramtion: Salina anhydrite/salt/dolomite
Sample ID: Burger_23_6782

Dolomite is the dominant mineral in this sample; minor amounts of detrital quartz grains (Q) are still present. The original rock was probably a silty claystone composed of silt-rich and clay-rich laminae, which have been extensively replaced by dolomite (Dol). Trace amounts of barite? (Ba) are present, replacing dolomite. Visible pores (blue) are minor in abundance and mainly associated with the dolomitized silt-rich laminae. Micropores among the dolomite crystals are the principal pore type in this sample.

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 6782.0



1A



1B

PLATE 2 A-B

THIN SECTION PHOTOMICROGRAPHS

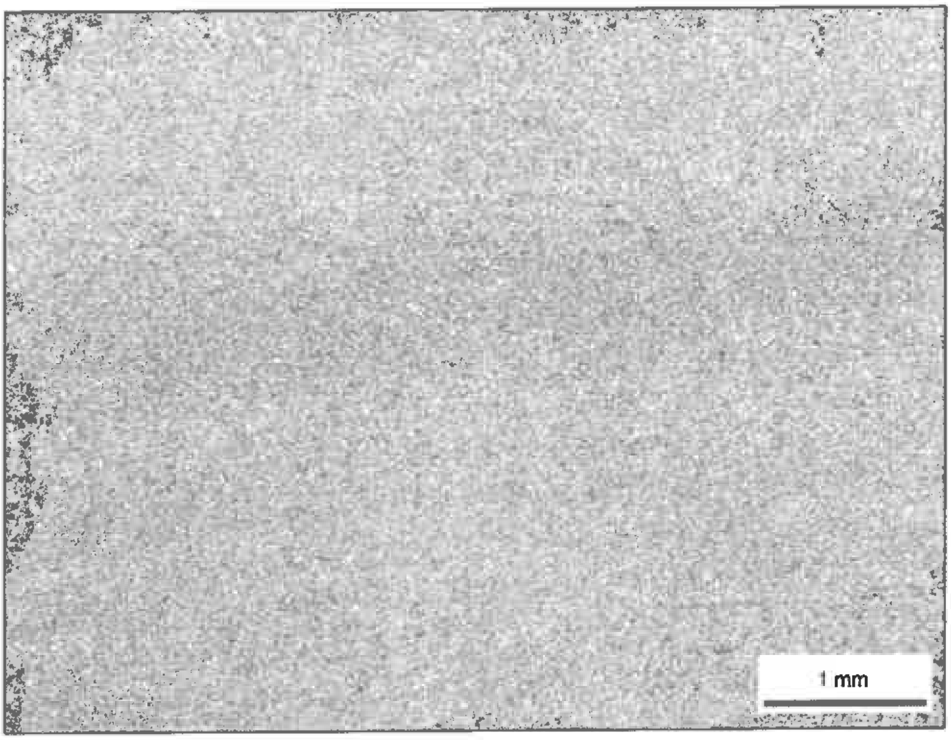
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 6865.0

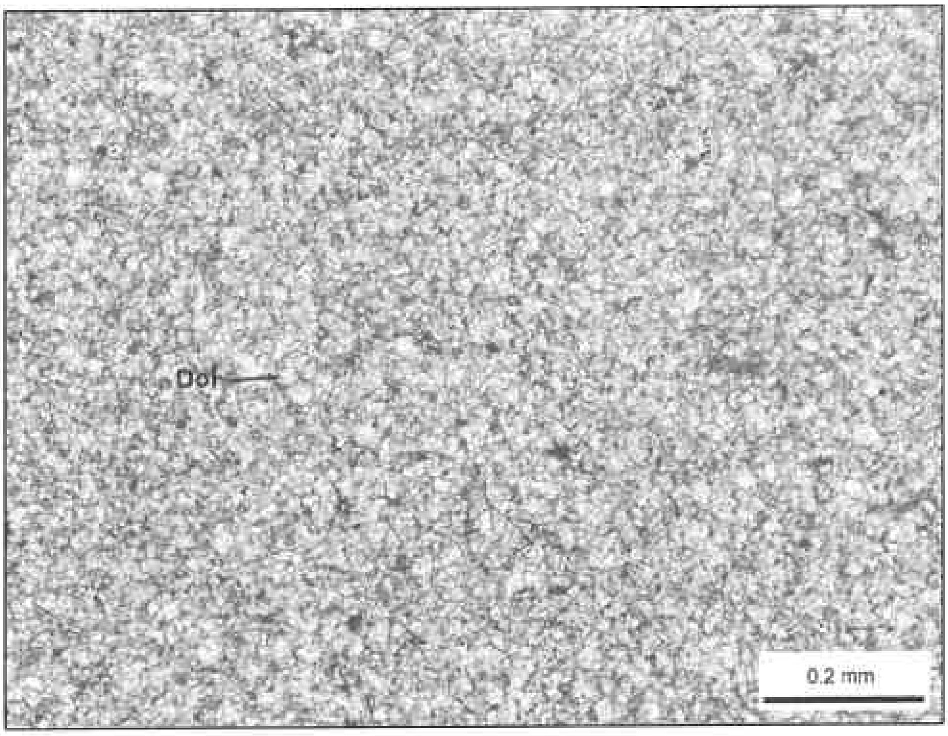
Lithology: Dolostone (dolomitized claystone)
Foramtion: Salina anhydrite/salt/dolomite
Sample ID: Burger_20_6865

This sample is a dolostone; it appears that the original rock was a laminated claystone, which has been thoroughly replaced by dolomite (Dol). Dolomite crystals are finely crystalline and exhibit an interlocking texture. Visible pores (blue) are very rare; micropores among the dolomite crystals make up the principal pore system in this sample.

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 6865.0



2A



2B

PLATE 3 A-B

THIN SECTION PHOTOMICROGRAPHS

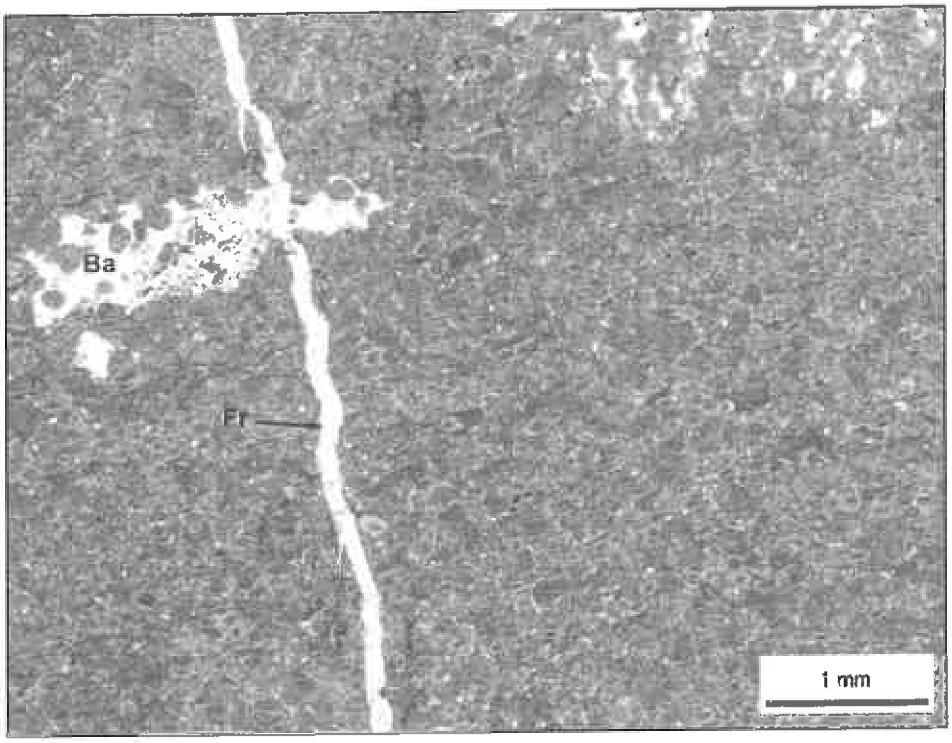
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 6905.0

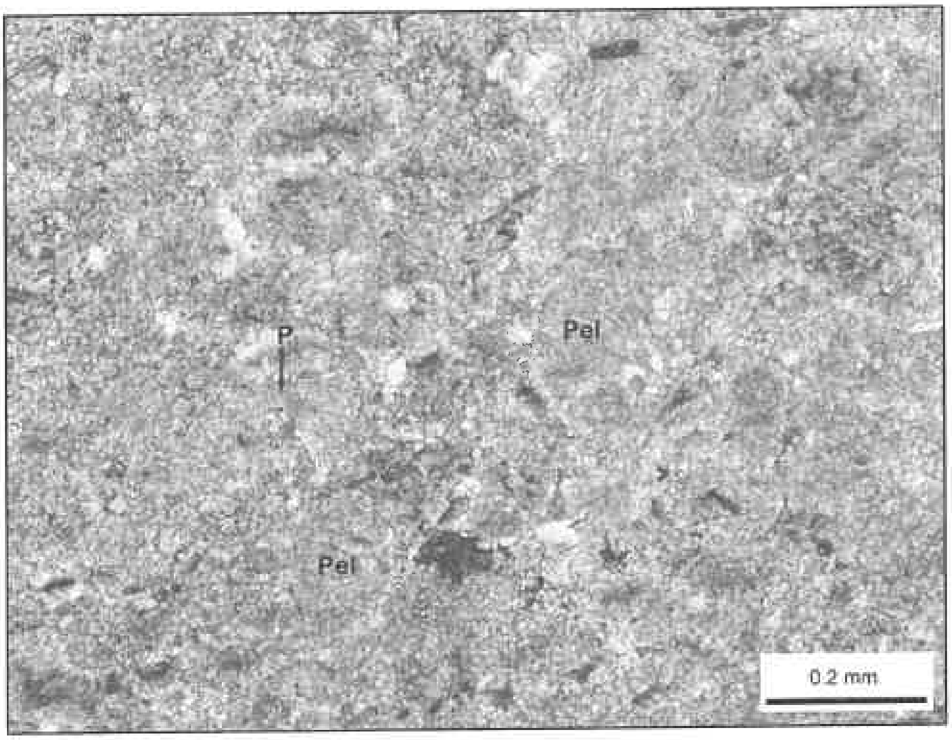
Lithology: Dolostone (dolomitized grainstone)
Foramtion: Salina anhydrite/salt/dolomite
Sample ID: Burger_19_6905

Visible pores (blue) are moderate to common in this dolostone and consist of interparticle (P) and intercrystalline pores. The original rock was a lime grainstone; peloids (Pel) are the most common allochem grains, which have been completely dolomitized. Fractures (Fr) are locally present and have been filled with clear dolomite crystals. Note that dolomite is locally replaced by barite (Ba).

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 6905.0



3A



3B

PLATE 4 A-B

THIN SECTION PHOTOMICROGRAPHS

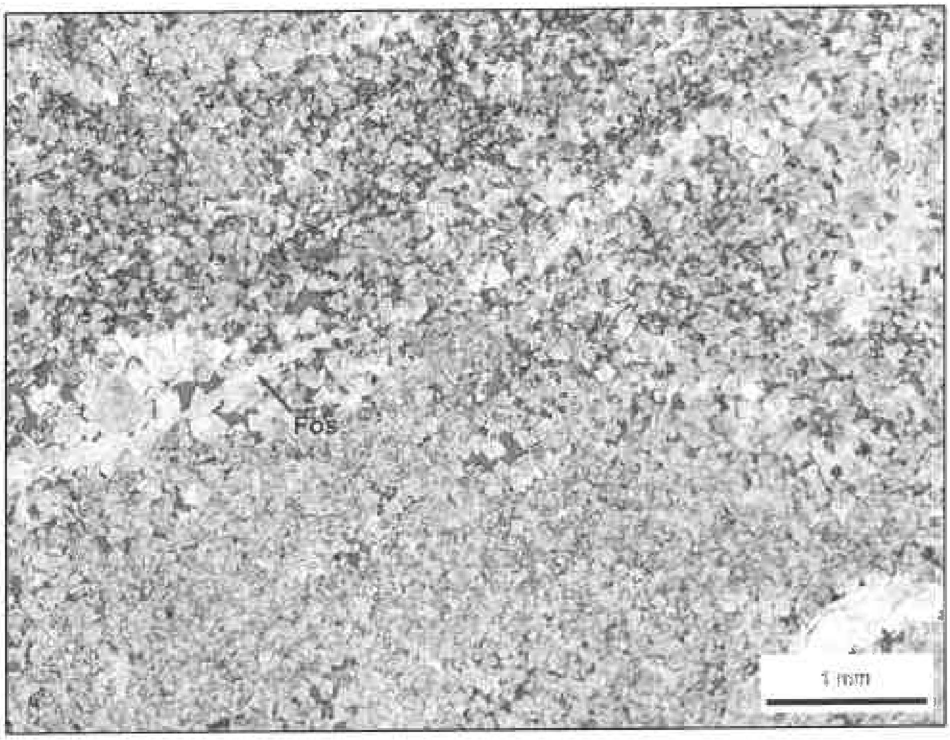
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 7476.0

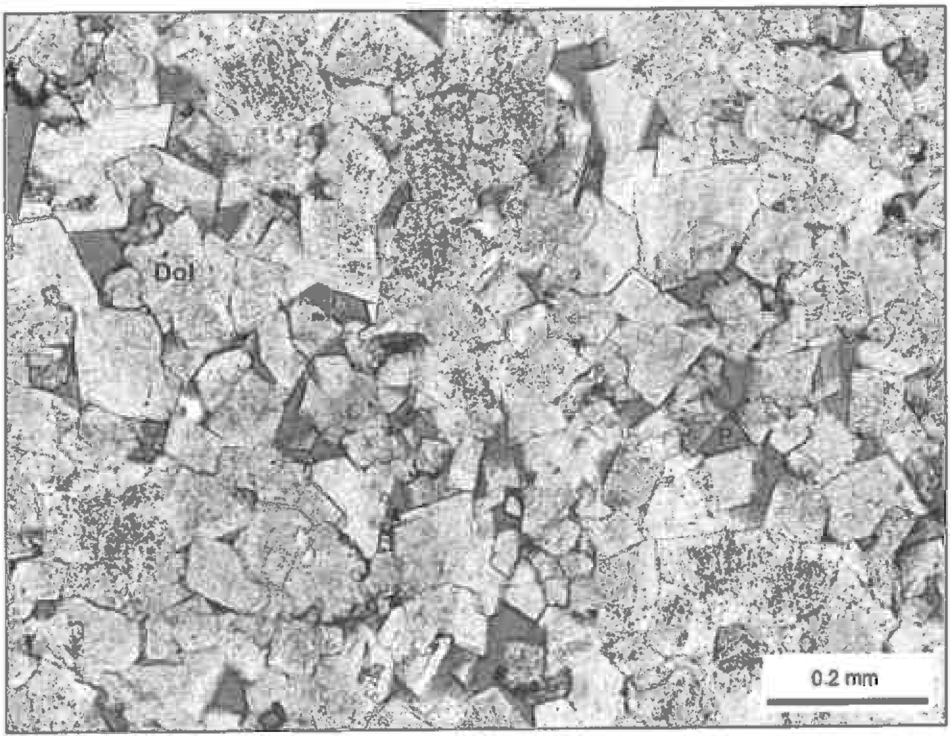
Lithology: Dolostone (dolomitized wackestone)
Foramtion: Lockport dolomite/limestone
Sample ID: Burger_13_7476

Visible pores (blue) are moderate to common in this dolostone and mostly intercrystalline pores (P). Intercrystalline pores are unevenly distributed; dolomite crystals are medium crystalline in texture. The original rock was probably a lime wackestone, which has been dolomitized. Some dolomitized "ghost" fossil fragments (Fos) are still recognizable.

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 7476.0



4A



4B

PLATE 5 A-B

THIN SECTION PHOTOMICROGRAPHS

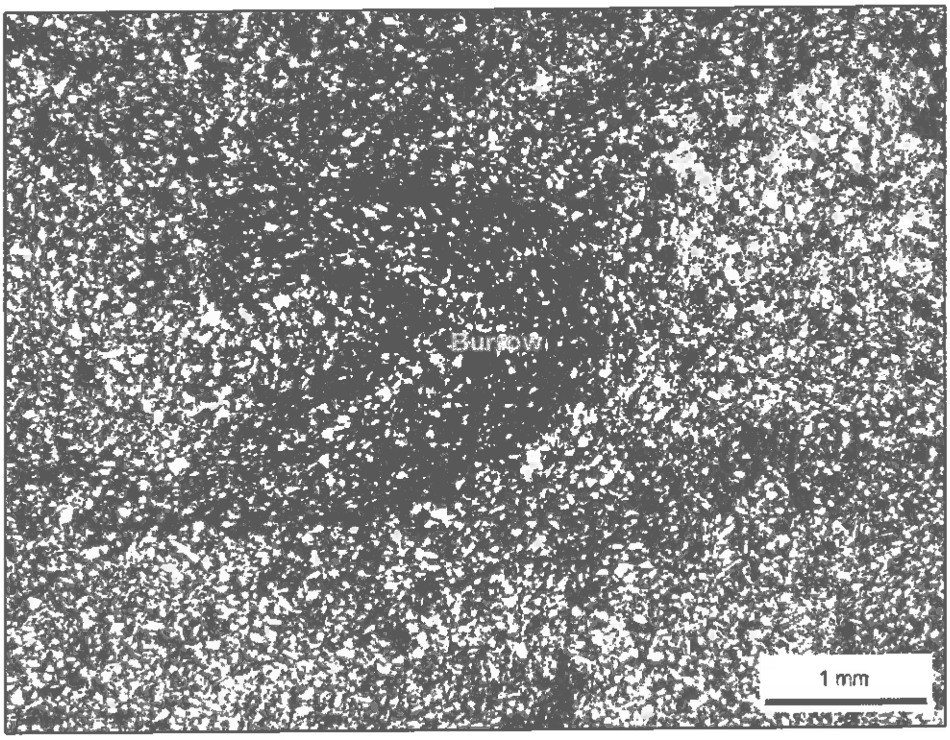
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 8133.0

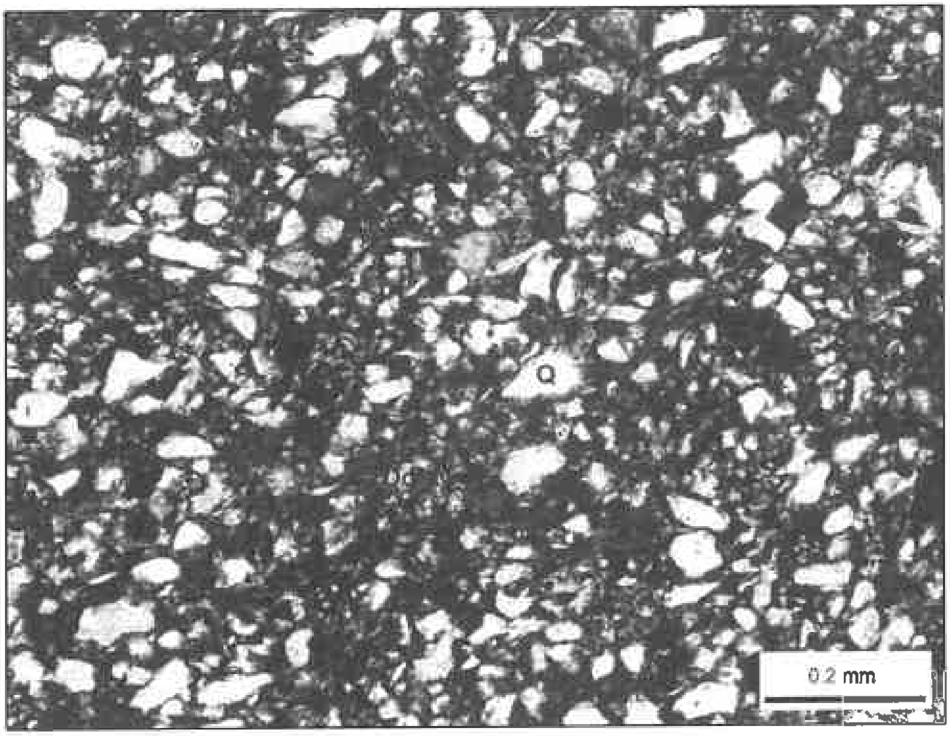
Lithology: Argillaceous siltstone
Foramtion: Red Clinton siltstone
Sample ID: Burger_9_8133

This sample is an argillaceous siltstone and is locally burrowed. The most common framework grains are quartz (Q), K-feldspar (KF; stained yellow) and plagioclase; these silt-sized grains are subangular in shape and moderately sorted. Intergranular areas are occluded by detrital clay matrix (Dclay), which contains minor amounts of highly dispersed hematite. No pores are visible; micropores associated with the detrital matrix are the principal pore type.

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 8133.0



5A



5B

PLATE 6 A-B

THIN SECTION PHOTOMICROGRAPHS

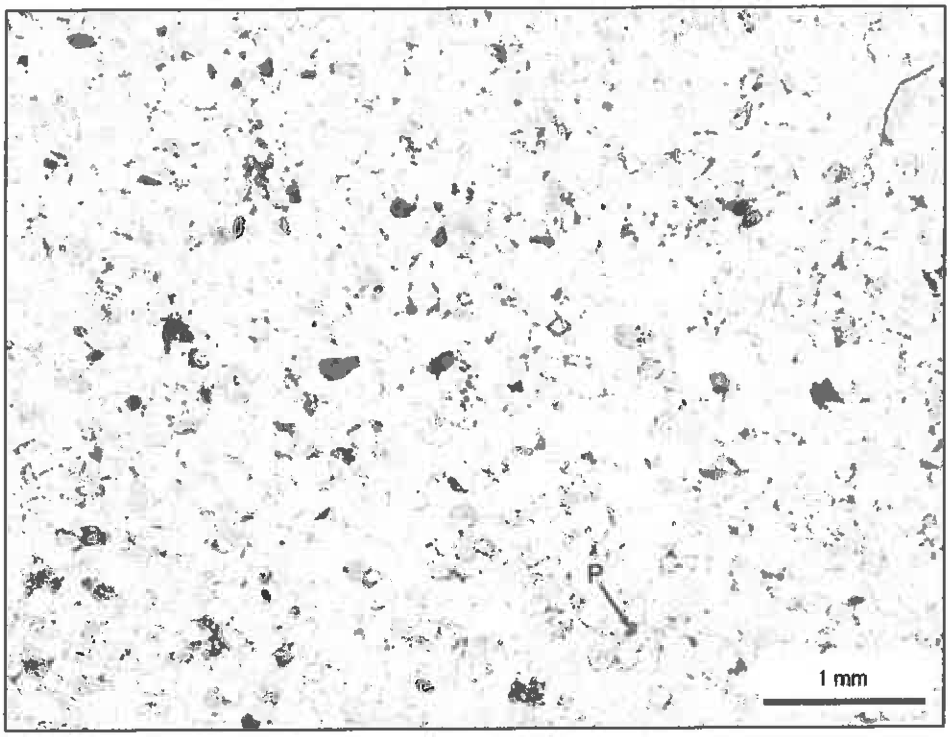
Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio

Depth (feet): 8235.0

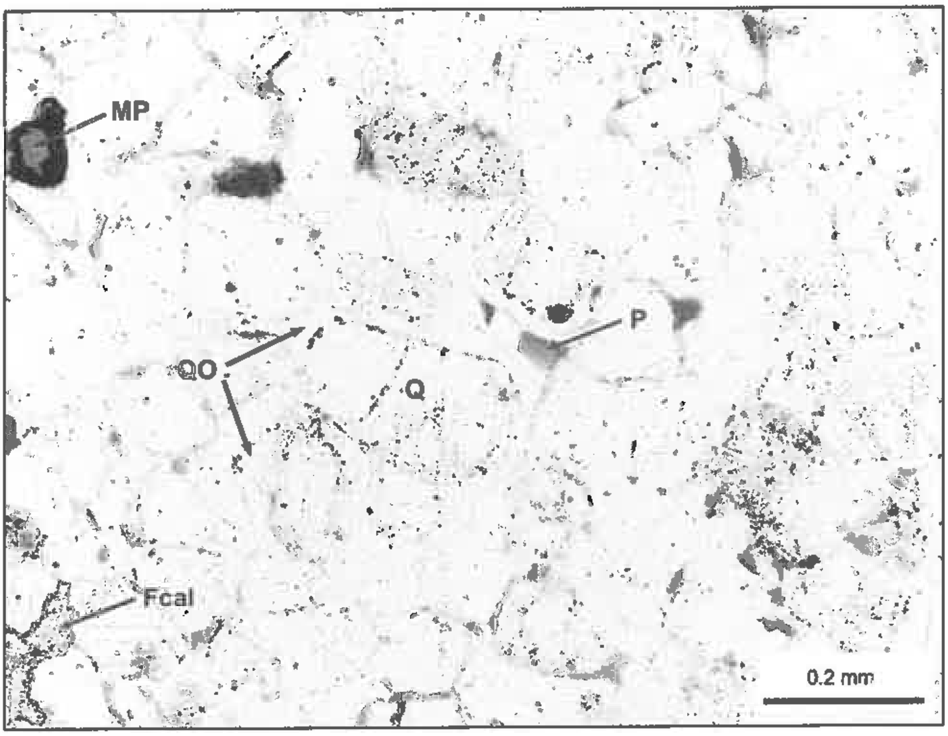
Lithology: Sandstone
Foramtion: White Clinton sandstone
Sample ID: Burger_6_8235

Quartz (Q) is the predominant framework constituent in this fine-grained sandstone; feldspars and lithic fragments (dark grains) are much less common. Framework grains are subrounded to rounded and well sorted. Intergranular areas are largely occluded by abundant quartz overgrowths (QO) and trace amounts of Fe-calcite (Fcal). Intergranular (P) and moldic (MP) pores are minor in abundance; micropores are probably minor and mainly associated with lithic fragments. Moldic pores are derived from the dissolution of feldspar grains and lithic fragments.

Battelle Memorial Institute
Burger Site Well
Belmont County, Ohio
Depth (feet): 8235.0



6A



6B

CMS-300 ROTARY SIDEWALL ANALYSIS

CMS-300 ROTARY SIDEWALL ANALYSIS

Battelle Memorial Institute

Burger Site
Belmont County, Ohio

CL File Number: HOU-071029

Date: 04/01/08

Battelle Memorial Institute
Burger Site
Belmont County, Ohio

CL File No.: HOU-071029
Date: 04/01/08
Analyst(s): MRL

CMS-300 ROTARY SIDEWALL ANALYSIS

CL Sample Number	Sample ID	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (mD)	Permeability Kair (mD)	Beta ft(-1)	Alpha (microns)	Description	Grain Density (g/cm3)	Footnote
Rotary Run No. 1											
14-2	Burger_14_2000	2000.00	1200	4.29	17.8	28.0	8.24E+09	4.77E+02	Shale dk gry	2.778	(1)
13-2	Burger_13_2500.1	2500.10	1200	2.71	.003	.007	6.39E+14	7.87E+03	Shale dk gry	2.759	(1)
12-2	Burger_12_3000	3000.00	1200	2.87	.171	.248	8.95E+11	5.16E+02	Shale dk gry	2.782	(1)
11-2	Burger_11_3495	3495.00	1200	4.30	.037	.040	4.55E+12	5.74E+02	Shale dk gry	2.784	(1)
10-2	Burger_10_4005	4005.00	1200	3.91	.099	.107	1.36E+12	4.38E+02	Shale dk gry	2.798	(1)
9-2	Burger_9_4500	4500.00	1200	2.63	.005	.006	7.24E+13	1.23E+03	Shale dk gry pyr	3.064	(1)
8-2	Burger_8_5000	5000.00	1200	3.97	.013	.017	7.19E+12	3.05E+02	Shale dk gry	2.787	(1)
7-2	Burger_7_5286	5286.00	1200	3.45	.001	.002	1.72E+16	3.79E+04	Shale dk gry scarb	2.650	
6-2	Burger_6_5386	5386.00	1200	5.30	.012	.015	3.82E+13	1.45E+03	Shale dk gry scarb	2.760	
5-2	Burger_5_5440	5440.00	1200	4.91	103	106	1.98E+09	6.60E+02	Shale dk gry	2.783	(1)
4-2	Burger_4_5500	5500.00	1200	1.89		Below instrument limits			Shale blk vcarb	2.597	(2)
3-2	Burger_3_5616	5616.00	Ambient	5.35			NA	NA	Shale blk vcarb	2.498	(5)
2-2	Burger_2_5710	5710.00	1200	1.03		Below instrument limits			Ls gry vf-micro xln vfoss	2.706	(2)
1-2	Burger_1_5742	5742.00	Ambient	2.12			NA	NA	Ls gry vf-micro xln foss	2.660	(5)
12-1	Burger_12_5825	5825.00	1200	1.82	.002	.005	9.17E+14	9.35E+03	Ls gry vf-micro xln foss	2.680	
11-1	Burger_11_5875	5875.00	1200	1.03	.033	.037	2.62E+13	2.85E+03	Sst gry vfgr lmy	2.620	(1), (3)
10-1	Burger_10_5926	5926.00	Ambient	5.07			NA	NA	Sst wh vfgr lmy	2.658	(5)
9-1	Burger_9_5935	5935.00	Ambient	3.31			NA	NA	Sst lt gry vfgr lam lmy styl	2.659	(5)
8-1	Burger_8_5945	5945.00	1200	1.31	.003	.007	1.01E+15	9.77E+03	Sst lt gry vfgr lam lmy styl	2.658	
7-1	Burger_7_5955	5955.00	1200	1.05	.002	.006	1.64E+15	1.23E+04	Sst lt gry vfgr lmy	2.667	
6-1	Burger_6_6000	6000.00	Ambient	0.54			NA	NA	Ls gry vf-micro xln vfoss	2.709	(5)
5-1	Burger_5_6200	6200.00	1200	0.64	.0002	.001	1.38E+17	1.01E+05	Ls gry vf-micro xln vfoss	2.707	
4-1	Burger_4_6350	6350.00	1200	0.85	.002	.004	3.31E+15	1.71E+04	Ls gry vf-micro xln vfoss	2.718	
3-1	Burger_3_6450	6450.00	1200	0.43	.002	.004	3.36E+15	1.73E+04	Anhy gry lam sdol	2.903	(1)
2-1	Burger_2_6500	6500.00	1200	6.54	.002	.005	1.47E+15	1.17E+04	Dol gry vf-micro xln	2.842	
Rotary Run No. 2											
24	Burger_24_6515	6515.00	1200	1.00		Below instrument limits			Ls gry vf-micro xln foss	2.720	(2)
23	Burger_23_6782	6782.00	1200	9.82	.011	.017	1.01E+13	3.50E+02	Dol lt gry vf-micro xln	2.822	
22	Burger_22_6784	6784.00	1200	9.43	.014	.023	9.49E+12	4.23E+02	Anhy gry sdol	2.876	
21	Burger_21_6815	6815.00	1200	2.85	.010	.021	1.07E+14	3.48E+03	Anhy gry dol lam	2.896	
20	Burger_20_6865	6865.00	1200	5.91	.003	.006	1.57E+15	1.30E+04	Dol gry vf-micro xln	2.835	
19	Burger_19_6905	6905.00	1200	13.12	.370	.513	2.77E+10	3.24E+01	Dol tn vf-f micro xln	2.838	
18	Burger_18_6919	6919.00	1200	8.18	.037	.045	1.25E+12	1.44E+02	Dol dk gry vf-micro xln	2.830	

Battelle Memorial Institute
Burger Site
Belmont County, Ohio

CL File No.: HOU-071029
Date: 04/01/08
Analyst(s): MRL

CMS-300 ROTARY SIDEWALL ANALYSIS

CL Sample Number	Sample ID	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Klinkenberg (mD)	Permeability Kair (mD)	Beta ft(-1)	Alpha (microns)	Description	Grain Density (g/cm3)	Footnote
17	Burger_17_6988	6988.00	1200	7.53	.008	.010	8.41E+12	2.05E+02	Dol lt gry vf-micro xln	2.792	
16	Burger_16_7311	7311.00	1200	5.82	.884	.973	1.51E+11	4.24E+02	Dol gry vf-micro xln fract	2.832	(1)
15	Burger_15_7326	7326.00	1200	6.71	2.45	2.60	7.89E+10	6.17E+02	Dol gry vf-micro xln shy lam fra	2.814	(1)
14	Burger_14_7369	7369.00	1200	8.08	.004	.009	6.68E+14	8.52E+03	Dol gry vf-micro xln shy lam	2.833	
13	Burger_13_7476	7476.00	1200	8.35	1.38	1.50	8.32E+10	3.68E+02	Dol dk gry vf-micro xln	2.839	
12	Burger_12_7582	7582.00	1200	1.85	.001	.002	1.56E+16	3.59E+04	Ls dk gry vf-micro xln	2.730	
11	Burger_11_7856	7856.00	1200	3.30	.015	.030	4.85E+13	2.32E+03	Shale dk rd-gry	2.824	
10	Burger_10_8013	8013.00	1200	1.37	.002	.004	2.85E+15	1.61E+04	Anhy gry shy calc	2.897	
9	Burger_9_8133	8133.00	1200	2.57	.0002	.001	1.46E+17	1.03E+05	Shale rd	2.733	
8	Burger_8_8180	8180.00	1200	2.71	.001	.001	2.47E+16	4.45E+04	Shale gry-rd	2.682	
7	Burger_7_8224	8224.00	1200	3.25	.002	.005	2.08E+15	1.38E+04	Sst gry-wh vfgr lam	2.646	
6	Burger_6_8235	8235.00	1200	3.21	.003	.007	9.22E+14	9.36E+03	Sst gry-wh vfgr	2.647	
5	Burger_5_8245	8245.00	1200	3.39	.215	.269	1.20E+11	8.38E+01	Sst gry-wh vfgr lam	2.670	(1)
3	Burger_3_8260	8260.00	1200	3.32	.128	.150	8.53E+11	3.46E+02	Sst gry-dk gry vfgr vshy lam	2.763	(1)
2	Burger_2_8269	8269.00	1200	3.05	.036	.041	3.64E+12	4.13E+02	Sst gry-dk gry vfgr shy lam	2.754	(1)
1	Burger_1_8332	8332.00	1200	2.58	.0003	.001	8.20E+16	7.84E+04	Shale rd	2.729	

Footnotes :

(1) : Denotes fractured or chipped sample. Permeability and/or porosity may be optimistic.
(2) : Sample permeability below the measurement range of CMS-300 equipment at indicated net confining stress (NCS). Data unavailable.
(3) : Denotes very short sample, porosity may be optimistic due to lack of conformation of boot material to plug surface.
(4) : Sample contains bitumen or other solid hydrocarbon residue.
(5) : Denotes sample unsuitable for measurement at stress. Porosity determined using Archimedes bulk volume at ambient conditions.
Sample unsuitable for permeability measurement.

Shaded areas denote previously reported data.

APPENDIX A: EXPLANATION OF CMS-300 TERMS "b", "Beta, and "Alpha"

K_∞	=	Equivalent non-reactive liquid permeability, corrected for gas slippage, mD
K_{air}	=	Permeability to Air, calculated using K_∞ and b, mD
b	=	Klinkenberg slip factor, psi
β (Beta)	=	Forcheimer inertial resistance factor, ft^{-1}
α (Alpha)	=	A factor equal to the product of Beta and K_∞. This factor is employed in determining the pore level heterogeneity index, H_i.
H_i	=	$\log_{10}(\alpha ø/RQI)$ α, microns = $3.238E^{-9}\ \beta K_\infty$
Ø	=	Porosity, fraction
RQI	=	Reservoir Quality Index, microns
RQI	=	$0.0314(K/ø)^{0.5}$

For further information please refer to:

Jones, S.C.: "Two-Point Determination of Permeability and PV vs. Net Confining Stress" <u>SPE Formation Evaluation</u> (March 1988) 235-241.

Jones S.C.: "A Rapid Accurate Unsteady-State Klinkenberg Permeameter," <u>Soc. Pet. Eng. J.</u> (Oct. 1972) 383-397.

Jones, S.C.: "Using the Inertial Coefficient, β, To Characterize Heterogeneity in Reservoir Rock: <u>SPE 16949</u> (September 1987).

Amaefule, J.O.; Kersey, D.G.; Marschall, D.M.; Powell, J.D.; Valencia, L.E.; Keelan, D.K.: "Reservoir Description: A Practical Synergistic Engineering and Geological Approach Based on Analysis of Core Data,: <u>SPE Technical Conference</u> (Oct. 1988) SPE 18167.

PLUG PHOTOS

Battelle Memorial Institute
Burger Site
Belmont County, Ohio

Sample #: **14-2**
Depth : **2,000.0'**

Sample #: **13-2**
Depth : **2,500.1'**

Sample #: **12-2**
Depth : **3,000.0'**

Sample #: **11-2**
Depth : **3,495.0'**

5" 1"

Job #: Hou-071029

Battelle Memorial Institute

Burger Site

Belmont County, Ohio

Sample #: **10-2**
Depth: **4,005.0'**

Sample #: **9-2**
Depth: **4,500.0'**

Sample #: **8-2**
Depth: **5,000.0'**

Sample #: **7-2**
Depth: **5,286.0'**

.5" 1"

Job #: Hou-071029

Battelle Memorial Institute

Burger Site

Belmont County, Ohio

Sample #: **6-2**
Depth: **5,386.0'**

Sample #: **5-2**
Depth: **5,440.0'**

Sample #: **4-2**
Depth: **5,500.0'**

Sample #: **3-2**
Depth: **5,616.0'**

.5" 1"

Job #: Hou-071029

Battelle Memorial Institute
Burger Site
Belmont County, Ohio

Sample #: **2-2**
Depth: **5,710.0'**

Sample #: **1-2**
Depth: **5,742.0'**

Sample #: **12-1**
Depth: **5,825.0'**

Sample #: **11-1**
Depth: **5,875.0'**

.5" 1"

Job #: Hou-071029

Battelle Memorial Institute

Burger Site

Belmont County, Ohio

Sample #: **10-1**
Depth: **5,926.0'**

Sample #: **9-1**
Depth: **5,935.0'**

Sample #: **8-1**
Depth: **5,945.0'**

Sample #: **7-1**
Depth: **5,955.0'**

.5" 1"

Job #: Hou-071029

Battelle Memorial Institute

Burger Site
Belmont County, Ohio

Sample #: **6-1**
Depth : **6,000.0'**

Sample #: **5-1**
Depth : **6,200.0'**

Sample #: **4-1**
Depth : **6,350.0'**

Sample #: **3-1**
Depth : **6,450.0'**

5" 1"

Job #: Hou-071029

Battelle Memorial Institute

Burger Site

Belmont County, Ohio

Sample #: **2-1**
Depth : **6,500.0'**

Sample #:
Depth :

Sample #:
Depth :

Sample #:
Depth :

5" 1"

Job #: Hou-071029

APPENDIX E

UIC PERMIT

State of Ohio Environmental Protection Agency

STREET ADDRESS:
Lazarus Government Center
50 W. Town St., Suite 700
Columbus, Ohio 43215

TELE: (614) 644-3020 FAX: (614) 644-3184
www.epa.state.oh.us

MAILING ADDRESS:
P.O. Box 1049
Columbus, OH 43216-1049

September 3, 2008

Mr. Charles D. Lasky
VP Fossil Ops and Air Quality Compliance
FirstEnergy Generation Corporation
76 South Main Street
Akron, Ohio 44308

VIA OVERNIGHT MAIL

Re: R.E. Burger Final UIC Class V 5X25 Permit to Operate

Dear Mr. Lasky:

On May 23, 2008, Ohio EPA issued a draft Class V 5X25 Underground Injection Contol (UIC) permit to operate for FirstEnergy Generation Corporation (FirstEnergy). This draft action on the permit to operate application was issued in accordance with Ohio Revised Code Section 6111. and Ohio Administrative Code (OAC) Chapter 3745-34. A public information session and a public hearing were held on June 24, 2008. The public comment period extended from May 23, 2008, through July 7, 2008. No comments were received that provided evidence that Ohio EPA should not issue the permit, based on standards established in the UIC regulations and statutes.

Final action on the permit application, resulting in the final permit to operate, was issued on September 2, 2008. The permit to operate will become effective on September 3, 2008 and will expire on December 31, 2009 or when the maximum injection volume is reached, whichever is achieved first.

You are hereby notified that this action of the Director is final and may be appealed to the Environmental Review Appeals Commission pursuant to Section 3745.04 of the Ohio Revised Code. The appeal must be in writing and set forth the action complained of and the grounds upon which the appeal is based. It must be filed with the Environmental Review Appeals Commission within thirty (30) days after notice of the Director's action. A copy of the appeal must be served on the Director of the Ohio Environmental Protection Agency and the Environmental Enforcement Section of the Office of the Attorney General within three (3) days of filing with the Board. An appeal may be filed with the Environmental Review Appeals Commission at the following address:

Environmental Review Appeals Commission
309 South Fourth Street, Room 222
Columbus, Ohio 43215.

One copy of the final permit to operate is enclosed for FirstEnergy's files and reference. Should you have any questions regarding this matter, please contact Lindsay Taliaferro, Underground Injection Control Unit Supervisor at (614) 644-2752.

Sincerely,

for MB

Michael G. Baker
Chief, DDAGW

MB/cl
FirstEnergyBattelle2008final.wpd

cc: w/attachments
Michelle Somerday, FirstEnergy Generation Corporation
Philip E. Jagucki, Program Manager, Battelle Memorial Institute

cc: w/o attachments
Craig Butler, Chief, SEDO
Tom Allen, Assistant Chief, DDAGW
Lindsay C. Talaiferro, UIC Unit Supervisor, DDAGW
Valoria Robinson, USEPA, Region V, WD-17J
Chuck Lowe, Geologist, DDAGW
Kimberly Rhoads, Legal
Central File--Correspondence

OHIO E.P.A.
SEP - 2 2008

OHIO ENVIRONMENTAL PROTECTION AGENCY

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL 5 X 25 PERMIT TO OPERATE: CLASS V Experimental Technology Well

Ohio Permit No.: UIC 05-07-01-PTO-V
US EPA ID No.: N/A
API No.: 34-013-2-0586

Date of Issuance: September 2, 2008
Effective Date: September 3, 2008
Date of Expiration: December 31, 2009
(or until Part II (B) (3) of the PTO is satisfied)

I certify this to be a true and accurate copy of the official documents as filed in the records of the Ohio Environmental Protection Agency.

By: Inge Lassiter Date: 9-2-08

Name of Applicant:	FirstEnergy Generation Corporation MRCSP - FEGENCO No. 1
Mailing Address:	76 South Main Street Akron, Ohio 44308
Facility Location:	R. E. Burger Plant 57246 Ferry Landing Road Shadyside, Ohio 43947
County:	Belmont **Township:** Mead
Section:	Section 35
Latitude/Longitude:	39° 54' 45.73"N / 80° 45' 51.32"W
Injection Intervals:	Oriskany Sandstone from 5923 to 5954 feet bgl; Salina Formation from 6734 to 7048 feet bgl; and, "Clinton" Sandstone from 8207 to 8274 feet bgl.
Injection Zone:	Oriskany Sandstone through "Clinton" Sandstone from 5923 feet to 8274 feet bgl
Confining Zone:	Ohio Shale, undifferentiated, and Onondaga Limestone from 1850 feet to 5923 feet bgl

Pursuant to the Underground Injection Control rules of the Ohio Environmental Protection Agency codified at Chapter 3745-34 of the Ohio Administrative Code, the applicant (permittee) indicated above is hereby authorized to operate a Class V Experimental Technology injection well for injection of Carbon Dioxide (CO_2) as a supercritical fluid in the above referenced injection intervals at the above location. The applicant (permittee) must meet all restrictions set forth within this permit to operate.

All references to Chapter 3745-34 of the Ohio Administrative Code (OAC) are to all rules that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit:

A. Closure cost estimates & financial assurance;

B. Source and analysis of injectate;

C. Well construction;

D. Operation, monitoring and reporting requirements;

E. Contingent corrective action; and

F. Quality assurance acknowledgment

This permit shall become effective on 09/02/08 and shall remain in full force and effect during the life of the permit, unless 1) the statutory provisions of Section 3004(f), (g) or (m) of the Resource Conservation and Recovery Act ban or otherwise condition the authorizations in this permit; 2) the Agency promulgates rules pursuant to these sections which withdraw or otherwise condition the authorization in this permit; or 3) this permit is otherwise revoked, terminated, modified or reissued pursuant to OAC Rules 3745-34-23 and 3745-34-24. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable state and federal law or regulations.

This permit and the authorization to inject shall expire at midnight, unless terminated, on the date of expiration indicated.

C. Korleski

Chris Korleski, Director
Ohio Environmental Protection Agency

TABLE OF CONTENTS

ATTACHMENTS

A. CLOSURE COST ESTIMATES & FINANCIAL ASSURANCE

B. SOURCE AND ANALYSIS OF INJECTATE

C. WELL CONSTRUCTION

D. OPERATION, MONITORING AND REPORTING REQUIREMENTS

E. CONTINGENT CORRECTIVE ACTION

F. QUALITY ASSURANCE ACKNOWLEDGMENT

PART I

GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in operation of a Class V 5X25 (experimental technology) underground injection well in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDW). Any underground injection activity not specifically authorized in this permit is prohibited. Compliance with this permit during its term constitutes compliance for purposes of enforcement with Sections 6111.043 and 6111.044 of the Ohio Revised Code (ORC). Such compliance does not constitute a defense to any action brought under ORC Sections 6109.31, 6109.32 or 6109.33 or any other common or statutory law other than ORC Sections 6111.043 and 6111.044. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law. Nothing in this permit shall be constructed to relieve the permittee of any duties under applicable state and federal law, regulations, or permits.

B. PERMIT ACTIONS

1. Modification, Revocation, Reissuance and Termination. The Director may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with OAC Rules 3745-34-07, 3745-34-23, and 3745-34-24. Also, the permit is subject to minor modifications for cause as specified in OAC Rule 3745-34-25. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit conditions.

2. Transfer of Permits. This permit may be transferred to a new owner or operator only if it is modified, or revoked and reissued, pursuant to OAC Rule 3745-34-22(A), 3745-34-23 or 3745-34-24, as applicable.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to any other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with OAC Rule 3745-34-03 any information submitted to the Ohio EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, the Ohio EPA may make the information available to the public without further notice. If a claim is asserted, documentation for the claim must be tendered and the validity of the claim will be assessed in accordance with the procedures in OAC Rule 3745-34-03. If the documentation for the claim of confidentiality is not received, the Ohio EPA may deny the claim without further inquiry. Claims of confidentiality for the following information will be denied:

1, The name and address of the permittee; and,
2. Information which deals with the existence, absence or level of contaminants in receiving water and amounts or contents of the fluids injected.

E. DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all applicable UIC regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. Any permit noncompliance constitutes a violation of ORC Chapter 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or denial of a permit renewal application. Such noncompliance also may be grounds for enforcement action under other applicable state and federal law.

2. Penalties for Violations of Permit Conditions. Any person who violates a permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapter 6111. Any person who knowingly or recklessly violates permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense. It shall not be a defense, for a permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit or any order issued by the Director or a court of appropriate jurisdiction.

4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with

this permit. This may include accelerated or additional monitoring or testing or both. If such is performed, the data collected shall be submitted to Ohio EPA in a written report within 90 days of completion of all related activities.

5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. "Proper operation and maintenance" includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Duty to Provide Information. The permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit. To determine compliance with this permit, or to issue a new permit the permittee also shall furnish to the Director, upon request, copies of records required to be kept by this permit or applicable state or federal law.

7. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

   a. Enter permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;
   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
   c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
   d. Sample or monitor at reasonable times for the purposes of assuring permit compliance or as otherwise authorized by ORC Chapter 6111 and OAC Chapter 3745-34, any substances or parameters at any location.

8. Records.

   a. The permittee shall retain copies of records of all monitoring information, including all calibration and maintenance records and all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least three (3) years from the date of the sample, measurement or report, or for the duration of the permitted life of the well, whichever is longer. This period may be extended by the request of the Director.

b. The permittee shall maintain copies of records of all data required to complete the permit application form for this permit and any supplemental information submitted under ORC Rule 3745-34-16 for a period of at least three (3) years from the date the application was signed or for the duration of the permitted life of the well, whichever is longer. This period may be extended by request of the Director.

c. The permittee shall retain copies of records concerning the nature and composition of all injected fluids for three (3) years after the completion of well closure which has been carried out in accordance with the approved closure plan.

d. The permittee shall continue to retain such copies of records after the retention period specified by paragraphs (a) to (c) above, unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records. At least 90 days notice shall be provided prior to delivery of the records to the Director. The records shall be in a form acceptable to the Director.

e. Records of monitoring information shall include:
   i. The date, exact place, and time of sampling or measurements;
   ii. The name(s) of the individual(s) who performed the sampling or measurements;
   iii. A precise description of both sampling methodology and the handling and custody of samples;
   iv. The date(s) analyses or measurements were performed;
   v. The name(s) of the individual(s) who performed the analyses or measurements and the laboratory that performed the analyses or measurements;
   vi. The analytical techniques or methods used; and
   vii. All results of such analyses.

10. <u>Monitoring.</u> Samples and measurements taken for the purpose of any required monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rule 3745-34-13 (E) and any other monitoring required by applicable rule or this permit. Monitoring results shall be reported in a format acceptable to the Director and as set forth in Part I (E)(12) of this permit.

    a. The method used to obtain a representative sample of any fluid to be analyzed and the procedure for analysis of the sample shall comply with the method cited and described in Table I of 40 CFR Part 136.3 and/or Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Administrator of the U.S. EPA

b. The monitoring information shall include conditions of quality assurance for each type of measurement required for reporting by the operator. Reference to established, published criteria shall be made whenever possible.

11. Signatory Requirements. All applications, reports or other information, required to be submitted by this permit, requested by the Director or submitted to the Director, shall be signed and certified in accordance with OAC Rule 3745-34-17. Within thirty (30) days of the effective date of this permit, the permittee shall designate the duly authorized representative for all submissions required under this permit, in written form to the Director, in compliance with OAC Rule 3745-34-17 (B).

12. Reporting Requirements.

a. Planned Changes. The permittee shall give written notice to the Director, as soon as possible, of any planned physical alternations or additions to the permitted facility.

b. Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

c. Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in writing no later than thirty (30) days following each schedule date.

d. Twenty-four (24) Hour Reporting.

i. The permittee shall report to the Director any noncompliance which may endanger health or the environment. All available information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within twenty-four (24) hours:

1. Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; or
2. Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water;
3. Any failure to maintain mechanical integrity; or
4. Any release of carbon dioxide to the atmosphere.

ii A written submission also shall be provided within five (5) business days of the time the permittee becomes aware of instances of noncompliance . The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; the anticipated time it is expected to continue; whether the noncompliance has or has not been corrected; and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

e. Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in permit condition 12(d) (ii) above.
f. Other Information. When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts and corrected information in writing within ten (10) days.
g. Monthly operating reports shall be submitted as required in Part II of this permit.
h. Within thirty (30) days of receipt of this permit, the person designated as responsible for submission of reports pursuant to OAC Rule 3745-34-17 shall certify to the Director that he or she has read and is personally familiar with all terms and conditions of this permit. The Director shall be notified within ten (10) business days, in writing, if the designee or position is changed.

F. PLUGGING AND ABANDONMENT

1. Plan for Plugging and Abandonment. At least thirty (30) days before the well installed pursuant to this permit is taken out of service, the permittee shall submit a plan for the plugging and abandonment of the well per OAC Rule 3745-34-13(F) to the Ohio EPA. The required plan shall specify procedures and contain such other provisions as are necessary to ensure that no movement of fluids into an underground source of drinking water is allowed. After review and acceptance of this plan by Ohio EPA, that plan shall become a condition of this permit.

2. Temporary Disuse. A permittee who wishes to cease injection for longer than twelve (12) months may keep the well open only if the permittee:

   a. Has received written authorization from the Director; and
   b. Has submitted a plan to the Director, for approval, that the owner or operator will follow to ensure that the well will not endanger USDWs during the period of temporary disuse. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells unless waived by the Director in writing.

3. Closure Report. The permittee shall submit a closure report to the Director within thirty (30) days after abandoning the well. The report shall be certified

as accurate by the permittee and by the person who performed the closure operation (if other than the owner or operator). Such report shall consist of the results of activities conducted by the permittee and either:

a. A statement that the well was closed in accordance with the then effective Well Closure Plan; or
b. Where actual closure differed from the then effective Well Closure Plan, a written statement specifying the differences between the plan and the actual closure.

4. Standards for Well Closure. Prior to closing the well, the permittee shall:

   a. Conduct appropriate mechanical integrity testing of the well to ensure the integrity of that portion of the long string casing and cement that will be left in the ground after closure. Testing methods may include:

      i. Pressure tests with liquid or gas;
      ii. Radioactive tracer surveys;
      iii. Noise, temperature, oxygen activation, pipe evaluation or cement bond logs;
      iv. Any other test required by the Director.

5. Financial Responsibility for Closure. The owner or operator shall comply with closure financial assurance requirements of OAC Chapter 3745-34. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection.

G. MECHANICAL INTEGRITY

1. Standards. Each injection well shall maintain mechanical integrity as defined by OAC Rule 3745-34-34. The Director or his authorized representative shall be present during the test for demonstration of mechanical integrity, unless the Director or his authorized representative waives this requirement before the test occurs.

2. Periodic Mechanical Integrity Testing. The permittee shall conduct the mechanical integrity testing as follows:

   a. Long string casing, injection tubing and annular seal shall be tested by means of an approved pressure test in accordance with OAC Rule 3745-34-34 (b)(2). This test shall be performed upon completion of the well prior to injection, prior to injection into each of the subsequent proposed injection intervals listed on the cover page of this permit, and whenever there has been a well workover in which tubing is removed from the well, the packer is reset, or when loss of mechanical integrity becomes suspected during operation.

b. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-34(C) prior to beginning injection and at completion of the experimental permit to test for movement of fluid along the bore hole. The Director may require such tests whenever the well is worked over;

c. The permittee may request the Director to use any other test approved by the Administrator of the U.S. EPA in accordance with the procedures in OAC Rule 3745-34-34(D).

3. <u>Prior Notice and Report</u>. The permittee shall notify the Director of intent to demonstrate mechanical integrity at least thirty (30) calendar days prior to such demonstration. For those tests required in Part I(G)(2) (a, b and c) above, the permittee shall submit the planned test procedures to the Director for approval at the time of notification. At the discretion of the Director a shorter time period may be allowed. Plans for pressure testing of the long string casing, injection tubing and annular seal shall specify the planned test pressure. Reports of mechanical integrity demonstrations which include well logs shall include an interpretation of results by a knowledgeable log analyst. Such reports shall be submitted in accordance with the reporting requirements established in Part II (D) of this permit.

3. <u>Gauges</u>. The permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half (0.5) percent of full scale prior to each required test of mechanical integrity or, barring any damage to the gauge, every six (6) months. A copy of the calibration certificate shall be submitted to the Director or his or her representative at the time of demonstration and every time the gauge is calibrated. The gauge shall be marked in no greater than five (5) psi increments.

4. <u>Loss of Mechanical Integrity</u>. If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by OAC Rule 3745-34-34 is indicated during operation, the permittee shall halt the operation immediately and follow the reporting requirements as directed in Part I(E)(12) of this permit. The permittee shall not resume operation until mechanical integrity is demonstrated and the Director gives approval to recommence injection.

5. <u>Mechanical Integrity Testing on Requires From Director</u>. The permittee shall demonstrate mechanical integrity at any time upon written request from the Director.

H. FINANCIAL RESPONSIBILITY

1. Financial Responsibility. The permittee shall comply with the closure financial responsibility requirements of OAC Chapter 3745-34.

   a. The permittee shall maintain written cost estimates, in current dollars, for the Closure Plan as specified in OAC Chapter 3745-34. The closure cost estimate shall equal the maximum cost of closure at any point in the life of the facility operation.
   b. The permittee shall adjust the cost estimate of closure for inflation annually. This annually adjusted closure cost shall be submitted with the annual financial assurance to the Director in accordance with requirements set forth in OAC Rules 3745-55-42 as applicable.
   c. The permittee shall revise the closure cost estimate whenever a change in the Closure Plan increases the cost of closure. The revised cost estimates shall be adjusted for inflation as specified above in condition I (1) (b).
   d. If the revised closure estimates exceed the current amount of the financial assurance mechanism, the permittee shall submit a revised mechanism to cover the increased cost within thirty (30) business days after the revision specified in permit conditions I (1) (b) and (c) above.
   e. The permittee shall keep on file at the facility a copy of the latest closure cost estimate prepared in accordance with OAC Rules 3745-34-09(B) (9) and 3745-34-62 during the operating life of the facility. Said estimate shall be available for inspection in accordance with the procedures in permit condition Part I (E) (8) (b) of this permit.

2. Insolvency. In the event of:

   a. The bankruptcy of the trustee or issuing institution of the financial mechanism (not applicable to permittees using a financial statement); or
   b. Suspension or revocation of the authority of the trustee institution to act as trustee; or
   c. The institution issuing the financial mechanism losing its authority to issue such an instrument, the permittee shall notify the Director, in writing, within ten (10) business days.

   The owner or operator shall establish other financial assurance or liability coverage acceptable to the Director, within sixty (60) days after such an event.

   An owner or operator shall also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy). U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor of a corporate guarantee shall make such a notification if named as debtor, as required under the terms of the guarantee.

I. CORRECTIVE ACTION

The permittee shall cease injection and shut-in the well if the permittee or Ohio EPA determines that continued operation thereof may be causing the upward migration of fluid through the well bore of any improperly closed or abandoned well within the area of review and shall take such steps necessary to close the well bore(s) to prevent the upward fluid movement. Any operation of the well which may cause the upward fluid migration from an improperly closed or abandoned well will be considered a violation of this permit.

PART II

WELL SPECIFIC CONDITIONS FOR CLASS V 5X25 EXPERIMENTAL TECHNOLOGY PERMIT

A. CONSTRUCTION

1. Siting. The injection well shall directly place injectate only into the injection intervals as defined on the cover page of this permit. At no time shall injection occur directly into any formation(s) above the injection intervals.

2. Casing and Cementing. Notwithstanding any other provisions of this permit, the permittee shall maintain casing and cement in the well in such a manner as to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of the well at the time of permit issuance are shown in Attachment C of this permit. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation.

3. Tubing and Packer Specifications. Injection shall take place only through approved tubing and packer set at a point immediately above or within one hundred (100) feet of the top perforation of the injection interval. Tubing and packer specifications shall be as represented in engineering drawings contained in Attachment C of this permit unless altered due to an Agency approved well workover. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation.

4. Wellhead Specifications. A quarter-inch (1/4") female coupling shall be maintained on the wellhead, to be used for independent injection pressure readings.

B. OPERATIONS

1. Injection Interval. Injection shall be limited to the injection intervals identified on the cover page of this permit.

2. Injection Pressure Limitation. Injection pressure at the wellhead shall not exceed a maximum limitation which is specified in Attachment D of this permit and shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures, or propagate existing fractures in the confining zone, or cause the movement of injection or formation fluids into an underground source of drinking water.

Bottom-hole pressure shall be limited so that the maximum bottom-hole pressure specified in Attachment D is never exceeded, calculated with a fracture gradient of 0.75 psi/foot. The injection pressure shall be limited so that a maximum surface injection pressure is not exceeded. The maximum surface injection pressure shall be adjusted downward if the fluid specific gravity increases above 0.94, in accordance with the calculation set forth in Attachment D of this permit. Regardless of the fluid specific gravity, a fracture gradient of 0.75 psi/ft shall not be exceeded under any circumstance.

3. Additional Injection Limitation. No substances other than those meeting the following limitations shall be injected. The permittee shall submit a certified statement attesting to compliance with this requirement upon expiration of the permit. The permittee shall limit injection to a maximum of 3,000 tons of carbon dioxide over the duration of this permit. The volume limit may be adjusted with the Director's approval.

4. Annulus Fluid and Pressure. Except during workovers, the annulus between the injection tubing and the long string casing shall be filled with an inert, non-reactive fluid. The permittee shall fill the annulus between the tubing and the long string casing with a fluid approved by the Director and identified in the administrative record of this permit. Any change in the annulus fluid shall be submitted by the permittee for the approval of the Director before replacement.

5. Annulus/Tubing Pressure Differential. The pressure on the annulus shall be at least fifty (50) psig higher than injection pressure at all times throughout the injection tubing length, for the purpose of leak detection.

6. Automatic Warning and Shut-Off System.

   a. The permittee shall continuously operate and maintain an automatic warning and shut-off system which shall stop injection in the following situation:

      I. Injection pressure measured at either the wellhead or bottom-hole pressure reaches the pressure limits specified in Attachment D of this permit.
      II. When injection/annulus pressure differential falls below fifty (50) psig.

   b. The permittee shall test the automatic warning and shut-off system at least once every twelfth month. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or his or her representative. The permittee shall notify the Director of their intent to test the automatic warning and shut-off system at least thirty (30) calendar days prior to such a demonstration. At the discretion of the Director a shorter time period may be allowed. The permittee shall submit the planned automatic warning and shut-off system test procedures to the Director for approval at the time of notification.

c. If an automatic alarm or shutdown is triggered, the owner or operator shall investigate immediately and identify as expeditiously as possible the cause of the alarm to shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or otherwise indicates that the well may be lacking mechanical integrity, the owner or operator shall:

   i. Immediately cease injection of waste fluids unless authorized by the Director to continue or resume injection; and
   ii. Take all necessary steps to determine the presence or absence of a leak; and,
   iii. Notify the Director within twenty-four hours after alarm or shutdown in accordance with Part I (E) (12) of this permit.

7. Precautions to Prevent Well Blowouts. The permittee shall, at all times, maintain a pressure at the wellhead which will prevent the return of the injection fluid to the surface. If there is gas formation in the injection zone near the well bore, such gas must be prevented from entering the casing or tubing. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer shall be kept in proper operational status during workovers.

   The permittee shall follow the procedure below to assure that a backflow or blowout does not occur:
   a) Limit the temperature, pH or acidity of the injectate; and,
   b) Develop procedures necessary to assure that pressure imbalances do not occur.

C. MONITORING

1. Monitoring Requirements [OAC Rule 3745-34-38(B)]. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rule 3745-34-38 and any other monitoring required by applicable rule or this permit. The method used to obtain a representative sample of any fluid to be analyzed and the procedure for analysis of the sample shall be the one described in Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Director.

2. Injection Fluid Analysis (OAC Rule 3745-34-38). The injected fluids shall be analyzed no less frequently than quarterly for parameters which include, at a minimum, those listed below. A final list of parameters is included in the approved Waste Analysis Plan.

i. pH
ii. Specific Gravity
iii. Temperature
iv. Sulfur dioxide (SO_2)
v. Nitrogen oxide (NO_x)
vi. Carbon dioxide (CO_2)
vii. Particulate matter
viii. Fluoride
ix. Mercury

Results of the most recent analysis shall be submitted with each quarterly report. The report shall include statements demonstrating that the permittee is in compliance with the requirements of Part I (E) (10), Part II(C)(4) and Part II(D)(1) of this permit.

3. Waste Analysis Plan [OAC Rule 3745-34-57)].

a. The permittee shall develop a written Waste Analysis Plan which describes the procedures which he or she will carry out to comply with permit conditions (C)(1) and (C)(2) above. A copy of the plan shall be kept at the facility and be available for inspection. The sampling and analyses shall be performed in a manner consistent with the Ohio EPA Quality Assurance Plan requirements. At a minimum, the plan must specify:

   i. The parameters for which the waste will be analyzed and the rationale for the selection of these parameters;
   ii. The test methods which will be used to test for these parameters; and
   iii. The sampling method which will be used to obtain a representative sample of the waste to be analyzed, the frequency of sampling and analysis for each parameter.

   The injectate sampling location shall be at the pumphouse associated with the well. The permittee shall identify the types of tests and methods used to generate the monitoring data. The monitoring program shall conform to the one described in an approved Waste Analysis Plan. The permittee shall abide by the Quality Assurance Form (Attachment F) of this permit. This form shall be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

   The permittee shall assure that the Waste Analysis Plan (WAP) remains accurate and the analyses of any fluid sampled remain representative.

b. Should process or operating changes occur that may significantly alter the characteristics of the composite waste stream injected, the permittee shall again demonstrate to the satisfaction of the Director that the compatibility standards are met. Should the results of well testing or composite waste stream (injectate) analyses, required by this permit or Chapter 3745-34 of the OAC, indicate that waste compatibility standards have not been adequately addressed, the Director may:

i. Restrict certain incompatible wastes from being injected; or
ii. Require the permittee to make appropriate changes in well construction materials; or
iii. Require the permittee to conduct additional waste compatibility studies.

4. Continuous Monitoring and Recording Devices. Continuous monitoring and recording devices shall be maintained and operated to monitor surface injection pressure, flow rate, the pressure in the annulus between the tubing and the long string of casing, and the temperature of the injectate. Continuous monitoring devices shall be maintained and operated to monitor the injected volume and the specific gravity of the injectate. The total injected volume for the well shall be recorded at least daily.

D. REPORTING REQUIREMENTS [OAC Rules 3745-34-28 and 3745-34-38]

Specific reporting requirements of this permit in no way relieve the permittee of other applicable reporting requirements specified in any action of Ohio EPA or a court of appropriate authority.

1. Monthly Reports. The permittee shall submit monthly reports to the Director containing all of the information listed below and in format acceptable to the Director. The permittee shall refer to guidance prepared by Ohio EPA in development of monthly reports.

   a. A summary containing a description of the following events:

      i. Any non-compliance with conditions of the permit including but not limited to events that violate maximum or minimum limits for surface injection pressure, bottom-hole pressure or annulus/injection differential pressure. Report the date, the nature and cause of the non-compliance and the response taken;
      ii. Any non-operating period. Report the date, duration and cause of the non-operating period;
      iii. Any procedures conducted at the injection well other than routine procedures. Report the date and the reason for the non-routine operating procedures;
      iv. Any annulus fluid addition to or removal from the annulus system. Report the date, the time and cause for the addition or removal, the volume of fluid added or removed and specify fluid addition or removal;

v. Any periodic mechanical integrity testing. Report the date, the reason for the testing and the type of test(s);
vi. Any well workover. Report the date, the reason for the workover and the work completed;
vii. Any other testing of the injection well required by the Director. Report the date, the reason for testing and the type of test(s).

b. A graph showing, in contrasting symbols or colors, for each day of the month:

i. Maximum surface injection pressure;
ii. Maximum bottom-hole pressure;
iii. Minimum annulus/injection differential pressure.

The permitted maximum surface injection pressure and bottom-hole pressure and the permitted minimum annulus/injection differential pressure should be demarcated on the graph.

c. A graph showing injectate temperature (° F), annular fluid volume (gallons) and sight glass level (inches) for each day of the month. Measurements for these three parameters shall be collected concurrently at a designated time each day. The data also shall be presented in tabular form.
d. Daily maximum, minimum and average injectate specific gravity.
e. The monthly maximum, minimum and average values for surface injection pressure, annulus pressure, flow rate in gallons per minute and volume. For each maximum and minimum flow rate reported, list the surface injection pressure and annulus pressure occurring during the time the well was operating at this maximum or minimum rate.
f. The total volume of fluid injected into this well for the month and to date.
g. The combined monthly average flow rate to be calculated as specified in Attachment D of this permit.
h. Results of injection fluid analyses, specified in Part II(C)(2) of the permit, completed during the month.

2. Quarterly Reports. The permittee shall report the results of injectate analyses as stipulated in Part II(C)(2)(b) of this permit within fifteen (15) days after the end of the quarter.

3. Reports on Well Tests and Workovers. Within 30 calendar days after the activity the permittee shall submit to the Director the field results of demonstrations of mechanical integrity, any well workover or results of other tests required by this permit. A formal written report and interpretation of demonstrations of mechanical integrity (excluding annulus pressure tests), any well workover, or results of other tests required by this permit or otherwise required by the Director shall be submitted to the Director within 45 calendar days after completion of the activity.

4. The Permittee shall submit all required reports to:

   Ohio Environmental Protection Agency
   Division of Drinking and Ground Waters
   Underground Injection Control Unit
   50 W. Town Street, Suite 700
   P.O. Box 1049
   Columbus, Ohio 43216-1049

5. The Permittee shall adhere to the reporting requirements specified in Attachment D and Part II of this permit for reporting under permit condition Part II(D) above.

ATTACHMENT A

Closure Cost Estimate & Financial Assurance

May 5, 2008

Mr. Chuck Lowe
Division of Drinking and Ground Waters
Ohio EPA
Lazarus Government Center
122 South Front Street
Columbus, OH 43215

Re: Financial assurance documentation for R.E. Burger CO_2 Injection Test

Dear Mr. Lowe,

Please consider the attached documentation as demonstration of financial assurance for closure of the Class V UIC Well (FEGENCO well) proposed under the Midwest Regional Carbon Sequestration Partnership. The well is located at First Energy's R.E. Burger Plant in Shadyside, Ohio.

The documentation includes a copy of the Notice of Financial Award from the U.S. Department of Energy. Note that the award extends through September 30, 2009; we expect the injection test, pending a final permit, to be completed during calendar 2008.

Project closeout, including closure of well in accordance with UIC requirements is part of the project scope of work and is included in the awarded funding. We have estimated that closure costs will be $75,000 to $100,000 and include:

- No injection casing will be removed from the FEGENCO 1 well since it was cemented to surface.
- If well conditions suggest a need, inject brine to displace injected CO_2 away from the well. Remove all injection tubing and packers from the well.
- Install a Portland cement plug from the injection casing shoe to ground surface. Calculated volume, sacks of cement, and proposed cement interval are as follows:
    - Cement interval: 5 ft to 8,343 ft
    - Volume: 683 cubic feet
    - Sacks of cement: 580 sacks of Class A cement (15.6 ppg).
- Excavate a shallow hole around the wellhead. Cut off the wellhead and all casing at or slightly below ground surface and remove.
- Weld a steel plate across to top of the injection casing. This plate may be vented as needed or required by state inspector.
- Install an aboveground well location marker.
- The well site will be backfilled and the location restored as directed by First Energy.

We have also included a copy of the well diagram as currently constructed.

If you need any additional information, please feel free to contact me at 614/424-4901 or balld@battelle.org.

Sincerely,

David A. Ball

David A. Ball
Program Manager
Energy Systems

DOE F 4600 1f

(7/05)

U S DEPARTMENT OF ENERGY

NOTICE OF FINANCIAL ASSISTANCE AWARD

Under the authority of Public Law 95-91 DOE Organization Act, as amended by PL 109-58 Energy Policy Act 2005

1 PROJECT TITLE Midwest Carbon Sequestration Regional Partnership (MCSRP) - Phase II

2 INSTRUMENT TYPE
☐ GRANT ☒ COOPERATIVE AGREEMENT

3 RECIPIENT (Name, address, zip code)
Battelle Memorial Institute
505 King Avenue
Columbus, OH 43201-2696

4 INSTRUMENT NO
DE-FC26-05NT42589

5 AMENDMENT NO
A008

6 BUDGET PERIOD (2 of 2)
FROM 10/1/07 THRU 9/30/09

7 PROJECT PERIOD
FROM 10/1/05THRU 9/30/09

8 RECIPIENT PROJECT DIRECTOR (Name, phone and E-mail)
David Ball balld@battelle.org
(614) 424-4901

10 TYPE OF AWARD
☐ NEW ☒ CONTINUATION ☐ RENEWAL
☐ REVISION ☐ INCREMENTAL FUNDING

9 RECIPIENT BUSINESS OFFICER (Name, phone and E-mail)
Ules Jackson jacksonu@battelle.org
(614) 424-5447

11 DOE PROJECT OFFICER (Name, address, phone and E-mail)
National Energy Technology Laboratory
ATTN: Lynn Brickett Lynn.Brickett@netl.doe.gov
626 Cochrans Mill Road, P. O. Box 10940
Pittsburgh, PA 15236-0940
(412) 386-6574

12 ADMINISTERED FOR DOE BY (Name, address, phone and E-mail)
National Energy Technology Laboratory
ATTN: Jane H. Weaver Jane.Weaver@netl.doe.gov
626 Cochrans Mill Road, P. O. Box 10940
Pittsburgh, PA 15236-0940
(412) 386-4422 fax: (412) 386-6137

13 RECIPIENT TYPE
☐ STATE GOV'T ☐ INDIAN TRIBAL GOV'T ☐ HOSPITAL ☐ FOR PROFIT ORGANIZATION ☐ INDIVIDUAL
☐ LOCAL GOV'T ☐ INSTITUTION OF HIGHER EDUCATION ☒ OTHER NONPROFIT ORGANIZATION ☐ CORPORATION ☐ PARTNERSHIP ☐ SOLE PROPRIETOR ☐ OTHER (Specify)

14 ACCOUNTING AND APPROPRIATIONS DATA
150 / 2007 / 31 / 220311 / 61000000 / 25500 / 1610251 / $4,037,589

15 EMPLOYER I D NUMBER
a TIN 31-4379427
b DUNS 00-790-1598

16 BUDGET AND FUNDING INFORMATION

a CURRENT BUDGET PERIOD INFORMATION (Budget Period 2)

(1)	DOE Funds Obligated This Action	$ 4,037,589.00
(2)	DOE Funds Authorized for Carry Over	$ 274,091.00
(3)	DOE Funds Previously Obligated in this Budget Period	$ 0.00
(4)	DOE Share of Total Approved Budget	$ 10,780,086.00
(5)	Recipient Share of Total Approved Budget	$ 4,556,423.00
(6)	Total Approved Budget	$ 15,336,509.00

b CUMULATIVE DOE OBLIGATIONS

(1)	This Budget Period [Total of lines a (1) and a (3)]	$ 4,037,589.00
(2)	Prior Budget Periods	$ 6,678,186.00
(3)	Project Period to Date [Total of lines b (1) and b (2)]	$ 10,715,775.00

17 TOTAL ESTIMATED COST OF PROJECT, INCLUDING DOE FUNDS TO FFRDC $23,745,399 (DOE $17,458,272, Battelle $6,287,127)
(This is the current estimated cost of the project It is not a promise to award nor an authorization to expend funds in this amount)

18 AWARD AGREEMENT TERMS AND CONDITIONS
This award/agreement consists of this form plus the following
a Special terms and conditions
b Applicable program regulations (specify) ______ (Date) ______
c DOE Assistance Regulations, 10 CFR Part 600at http //ecfr gpoaccess gov or, if the award is a grant to a Federal Demonstration Partnership (FDP) institution, the FDP Terms & Conditions and the DOE FDP Agency Specific Requirements at http //www nsf gov/awards/managing/fed dem part jsp
d Application/proposal as approved by DOE
e National Policy Assurances to Be Incorporated as Award Terms in effect on date of award at http //grants pr doe gov

19 REMARKS
See attached pages.

20 EVIDENCE OF RECIPIENT ACCEPTANCE
Ules P. Jackson 10/5/07
(Signature of Authorized Recipient Official) (Date)
ULES P. JACKSON
CONTRACTING OFFICER
(Title)

21 AWARDED BY
Martin J Byrnes 9/26/07
(Signature) (Date)
Martin J. Byrnes
(Name)
Contracting Officer
(Title)

ATTACHMENT B

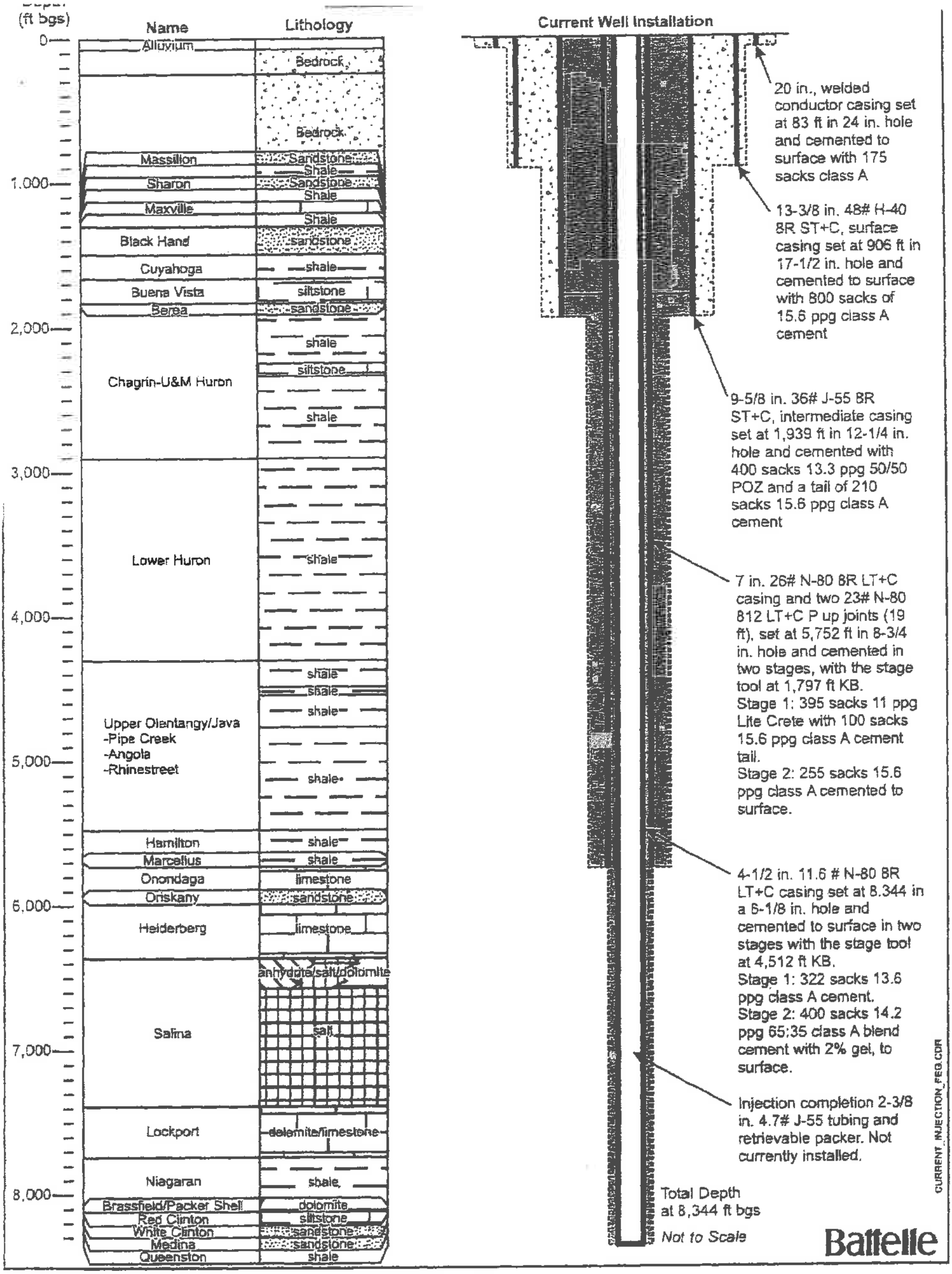
Source & Analysis of Injectate

Source and Analysis of Injectate

The source of the CO_2 shall be provided as an attachment to this permit. A laboratory analysis of the CO_2 shall be provided prior to injection the CO_2. The analysis shall be representative of the injected fluid. If the source of the CO_2 changes during the duration of the permit, the permittee shall provide a revised sample analysis. Injection is limited to CO_2 of which the laboratory analyses are representative. The CO_2 shall be compressed to a supercritical state prior to injection.

ATTACHMENT C

WELL CONSTRUCTION



Depth (ft bgs)
Name
Lithology
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
Alluvium
Bedrock
Bedrock
Massillon
Sandstone
Shale
Sharon
Sandstone
Shale
Maxville
Shale
Black Hand
sandstone
Cuyahoga
shale
Buena Vista
siltstone
Berea
sandstone
Chagrin-U&M Huron
shale
siltstone
shale
Lower Huron
shale
Upper Olentangy/Java
-Pipe Creek
-Angola
-Rhinestreet
shale
shale
shale
shale
Hamilton
shale
Marcellus
shale
Onondaga
limestone
Oriskany
sandstone
Helderberg
limestone
Salina
anhydrite/salt/dolomite
salt
Lockport
dolomite/limestone
Niagaran
shale
Brassfield/Packer Shell
dolomite
Red Clinton
siltstone
White Clinton
sandstone
Medina
sandstone
Queenston
shale
Current Well Installation
20 in., welded conductor casing set at 83 ft in 24 in. hole and cemented to surface with 175 sacks class A
13-3/8 in. 48# H-40 8R ST+C, surface casing set at 906 ft in 17-1/2 in. hole and cemented to surface with 800 sacks of 15.6 ppg class A cement
9-5/8 in. 36# J-55 8R ST+C, intermediate casing set at 1,939 ft in 12-1/4 in. hole and cemented with 400 sacks 13.3 ppg 50/50 POZ and a tail of 210 sacks 15.6 ppg class A cement
7 in. 26# N-80 8R LT+C casing and two 23# N-80 812 LT+C P up joints (19 ft), set at 5,752 ft in 8-3/4 in. hole and cemented in two stages, with the stage tool at 1,797 ft KB.
Stage 1: 395 sacks 11 ppg Lite Crete with 100 sacks 15.6 ppg class A cement tail.
Stage 2: 255 sacks 15.6 ppg class A cemented to surface.
4-1/2 in. 11.6 # N-80 8R LT+C casing set at 8,344 in a 6-1/8 in. hole and cemented to surface in two stages with the stage tool at 4,512 ft KB.
Stage 1: 322 sacks 13.6 ppg class A cement.
Stage 2: 400 sacks 14.2 ppg 65:35 class A blend cement with 2% gel, to surface.
Injection completion 2-3/8 in. 4.7# J-55 tubing and retrievable packer. Not currently installed.
Total Depth at 8,344 ft bgs
Not to Scale
Battelle
CURRENT_INJECTION_FEG.CDR

ATTACHMENT D

OPERATION, MONITORING AND REPORTING REQUIREMENTS

OPERATING, MONITORING AND REPORTING REQUIREMENTS

Characteristic	LIMITATION Maximum	MINIMUM MONITORING REQUIREMENTS Frequency	MINIMUM REPORTING REQUIREMENTS Frequency
* Injection Pressure	2006 psig (Oriskany) 2284 psig (Salina) 2790 psig (Clinton)	continuous	monthly
* Bottom-hole Pressure	4442 psig (Oriskany) 5050 psig (Salina) 6155 psig (Clinton)	continuous	monthly
** Injection Rate	99 gpm	continuous	monthly
*** Annulus Pressure		continuous	monthly
Differential Pressure (Tubing/Annulus)	50 psi minimum	continuous	monthly
+ Specific Gravity		continuous	monthly
Cumulative Volume		daily	monthly
Concurrent Measurements of:			
Annulus Sight Glass Level		daily	monthly
Annular Fluid Volume		daily	monthly
Injectate Temperature		daily	monthly
++ Chemical Composition of Injected Fluid		quarterly	quarterly

* Injection Pressure: The maximum allowable surface injection pressure (MASIP) shall be calculated using the following formula:

MASIP = Depth x [0.75 - (0.433 x (SpG + Safety factor)] – friction factor

Where:

0.75 = applied fracture gradient in psi/ft
0.05 = safety factor
25 = friction factor, using 2 3/8" O.D. tubing and proposed average injection rate (4.1 gpm)
0.89 = fluid specific gravity

Depth of the proposed Injection Zone(s) (top):

5923' = depth to the top of the Oriskany Fm. injection interval in feet;
6734' = depth to the top of the Salina Fm. injection interval in feet; or,
8207' = depth to the top of the Clinton Fm. injection interval in feet.

*Bottom-hole Pressure: The maximum allowable bottom-hole pressure (BHP_{max}) shall be calculated using the following formula:

$$BHP_{max} = (0.75) \times (\text{depth})$$

FirstEnergy proposes to inject approximately 1,000 tons of supercritical CO_2 into each injection zone. Each injection interval tested shall be limited to the maximum calculated injection pressures.

**Injection Rate: The monthly average injection rate shall not exceed 99 gallons per minute. The rate shall be calculated utilizing the total volume of fluid injected for a given month divided by the total number of minutes within that month.

***Annulus Pressure Requirement: The pressure on the annulus shall be maintained continuously at least 50 psi higher than the injection pressure throughout the entire length of the tubing.

+Specific Gravity: Specific gravity of the injectate shall be monitored continuously and the data recorded at a frequency approved by the Director. A daily maximum, minimum and average shall be reported monthly.

++Quarterly Waste Analysis: Chemical analysis of the injectate shall be conducted quarterly for, at a minimum, the waste constituents listed in Part II (C) (2) of this permit or in accordance with the Waste Analysis Plan approved by the Director.

1. Maximum Injection Pressure

(a) Prior to injection in this well, the permittee shall determine if the maximum injection pressure as specified in Part II (B) and Attachment D of this permit allows sufficient operational flexibility. If sufficient flexibility is allowed by the maximum injection pressure, the permittee may opt not to proceed with additional testing and the requirements of Attachment D. If the maximum injection pressure calculated prior to direct testing proves insufficient, or another need is identified that requires modifying the maximum injection pressure, the permittee shall conduct one or more of the following tests to ensure that the maximum injection pressure exerted during operation will not propagate existing or open new fractures in any part of the injection zone. In all cases where testing is to be performed, the permittee shall submit a plan for the Director's approval which describes the detailed procedures to be followed during the test designed to determine maximum injection pressure. Modification of the maximum permitted injection pressure following a test conducted under Attachment D of this permit shall follow the procedures as specified in ORC Rule 3745-34-27(B).

(1) In-Situ Stress Tests

The permittee shall isolate zones for testing the fracture pressure by means of a straddle packer assembly, or other comparable means. The zones selected for testing shall be those predicted to have the lowest fracturing value. The permittee shall use either fresh water to conduct this test or a fluid that is permissible for injection into this well as allowed by this permit. At a minimum, the permittee shall measure the test fluid for its specific gravity and viscosity during the In-Situ Stress test. The results of this test shall be submitted to Ohio EPA as specified in Part II (D) and Attachment D of this permit. Failure to report test results shall be considered grounds to deny a permit modification.

(2) Step Rate Test

The permittee shall isolate the entire injection interval by means of a packer assembly, or other comparable means. The permittee shall inject either fresh water for this test or a fluid that is permissible for injection into this well as allowed for in this permit. At a minimum, the permittee shall measure the test fluid for its specific gravity and viscosity during the Step Rate Test. The permittee shall inject into the well at increasing rates, holding the length of each rate step constant. Each rate step shall span the same amount of time (at least thirty (30) minutes per rate step is recommended). The permittee shall attempt to inject at three (3) rates which result in a pressure higher than the injection zone fracture pressure during this test. All measured times, rates, and pressures and a Cartesian plot of the rate against the final stabilized pressure at each step shall be included as a part of the data package submitted to Ohio EPA. The results or this test shall be submitted to Ohio EPA as specified in Part II (D) and Attachment D of this permit. Failure to report the test results shall be considered grounds to deny a requested permit modification.

(3) Other Test(s) Approvable by the Director

The permittee may choose to conduct test(s) other than those described in Attachment D (1) and (2) of this permit. If so, the permittee shall submit a plan to conduct alternative test(s) to the Director for approval prior to conducting the test(s).

(b) Reporting Maximum Injection Pressure Determination

The permittee shall report the results of the measurements and tests conducted in Attachment D (1) (a) of this permit within thirty (30) days of their completion.

2. Injection Fluid

The injectate is limited to CO_2, as a supercritical fluid, with the chemical composition indicated in Attachment B of this permit.

3. Special Completion and Operating Conditions for the "Clinton" Sandstone Injection Interval

(a) Prior to perforating the "Clinton" Sandstone injection interval, the cement bond log shall be re-run with the protection casing pressurized to equal the cementing pressure. The cement bond log should be run over the entire casing length.
(b) The injection rate shall be limited to a maximum rate of fifty (50) gallons per minute. The calculated maximum allowable surface injection pressure may not be exceeded at any time. The packer assembly should be placed within one hundred (100) feet of the top perforation and the tail pipe placed at the perforated interval.
(c) At the conclusion of injection into the "Clinton" injection interval, a radio-active tracer or other approved test shall be run to demonstrate which zone(s) received the CO_2.
(d) Upon conclusion of the demonstration project, a cement bond log shall be run to demonstrate cement integrity. Additional tests may be run to ascertain the casing integrity.

ATTACHMENT E

CONTINGENT CORRECTIVE ACTION

ATTACHMENT E

CORRECTIVE ACTION
[OAC Rules 3745-34-07 and 3745-34-30]

A. Protection of USDW

Should upward fluid migration occur through the wellbore of any previously unknown, improperly plugged or unplugged well in the ¼ mile radius area of review due to injection of fluids in this well, injection will be shut-in until proper plugging can be accomplished. Any flowage from such undiscovered wells will be considered noncompliance with this permit. Should any problem develop in the casing of the injection well, the injection well shall be shut-in until such repairs can be made to remedy the situation.

B. Required Action

No corrective action is required at this time.

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

ATTACHMENT F

Quality Assurance Acknowledgment

I hereby affirm that all chemical data submitted for Injection Well Permit Number UIC 05-07-01-PTO-V is of known quality and was obtained from samples using methods prescribed in the Ohio EPA Quality Assurance Plan and the "Waste Analysis Plan" developed. I also acknowledge the right of Ohio EPA to inspect the sampling protocols, calibration records, analytic records and methods, and relevant quality assurance and quality control information for the monitoring operations required by this permit or Chapter 3745-34 of the OAC.

Date

Authorized Agent Signature

For

APPENDIX F

MRCSP/EPRI DESIGN STUDY FOR POWERSPAN PILOT PLANT

APPENDIX F

Specification of Carbon Dioxide Compressor and Pipeline at R.E. Burger Plant

ACKNOWLEDGMENTS

Battelle acknowledges the support provided by Rob Steele at Electric Power Research Institute (EPRI) whose report *Specification of Carbon Dioxide Compressor and Pipeline at R. E. Burger Plant,* EPRI, Palo Alto, CA: 2009. 1019492 was used as a basis for this appendix.

Specification of Carbon Dioxide Compressor and Pipeline at R.E. Burger Plant

1.0 Background

The FirstEnergy Generation Corp. owns and maintains the R.E. Burger Plant on a 100-acre site on the Ohio River near Shadyside, Ohio. The facility has two coal-fired units, one coal-fired turbine peaking unit and three oil-fired peaking units that can produce 413 MW of electric power. The plant burns nominally one million tons of coal each year. The facility is shown in Figure 1-1 looking from south to north.

In 2004, Powerspan Corporation and the U.S. DOE NETL entered into a cooperative research and development agreement (CRADA) to develop a cost effective CO_2 removal process from flue gas for coal-based power plants. The regenerative process uses an ammonia solution to capture CO_2 in the flue gas and release it for subsequent sequestration. After regeneration the ammonia solution is recycled.

In September, 2005, FirstEnergy Corp. announced plans to pilot test the Powerspan CO_2 removal technology, ECO2, at the R.E. Burger plant where Powerspan has successfully demonstrated the ECO multi-pollutant control process.

The ECO2 CO_2 removal process will readily integrate with the existing Powerspan's ECO unit that has been in operation on a 50 MW slipstream since 2002. The ECO2 process will process 1 MW slipstream (approximately 20 short tons of CO_2 per day) from the 50 MW ECO unit.

Figure 2-1. R.E Burger 413 MW Coal Plant

In addition to testing the CO_2 capture technology, FirstEnergy Corp. announced in May, 2006, that the Burger Plant had been selected as a carbon sequestration test site by the Midwest Regional Carbon Sequestration Partnership (MRCSP). One option was to compress, transport and inject the CO_2 into the test injection well located on the plant property. If feasible, the CO_2 produced by the 1 MW Powerspan ECO2 pilot unit was to be used as opposed to purchased CO_2. The injection of CO_2 produced by the ECO2 unit depended on the successful startup and operation of the ECO2 pilot unit within the allotted time line of the project. This short report documents the process to select the required compression equipment and piping that would be required to compress the CO_2 produced by the ECO2 unit and transport it to the wellhead.

2.0 Site Description

The coal plant and the 50 MW ECO multi-pollutant unit are shown in Figure 2-1. It was determined that there was not enough available area near the existing ECO unit to install the compressor package. Figure 2-2 shows the proposed pipe routing and location of the compressor. Low pressure (50-100 psig) pipe will run above ground from the ECO2 unit to the compressor package. High pressure pipe (>2000 psig) will run below ground from the compressor to the well head. The low pressure pipe will remain outside the buildings until it connects to the compressor that would potentially be located inside the ECO crystallizer tent.

The FirstEnergy drawings and Powerspan drawings were used to layout the preliminary piping route. The length of piping from the existing ECO unit to the compressor was estimated to be 500 feet and the piping from the compressor to the well head was estimated to be 1,500 feet.

Powerspan pointed out the location of takeoff for the sequestration pipeline. The takeoff would be at the location of the existing BCU test loop.

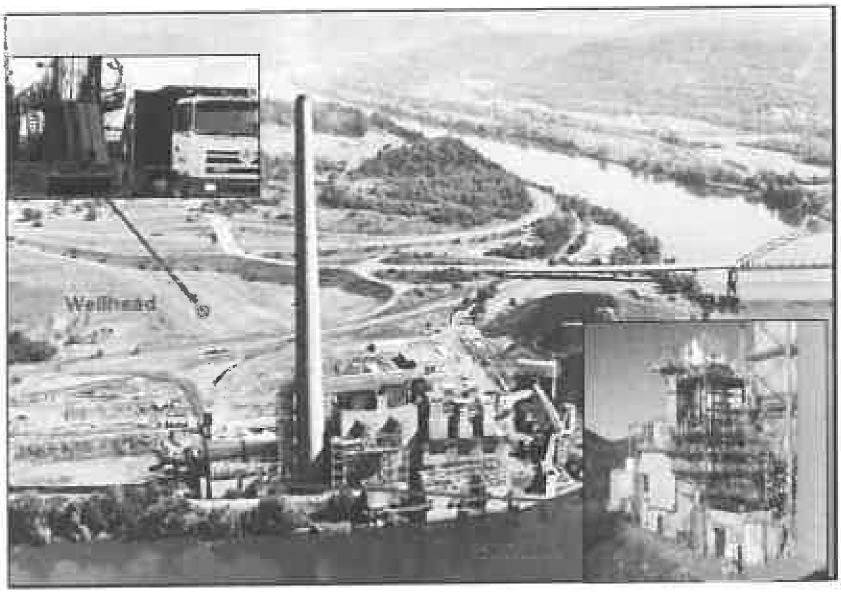


Figure 2-1. Site Layout of ECO Unit and Coal Plant

Figure 2-2. Aerial View of Burger Site with Proposed Pipeline Route

From this location out to the test well the pipeline should run underground. The underground piping in heavy haul areas should be reinforced for protection.

2.1 Compression Specification

A compression system was required to satisfy the wellhead injection pressure requirement of 1800 to 2000 psig. The compression requirement for the compressor was particularly unique for the combination of power size, flow rate, and final discharge pressure of greater than 2000 psig.

The nominal compressor specification was:

Suction (inlet) Pressure	50 – 100 psig
Suction Temperature	120°F
Flow Rate	345,000 scfd (20 short ton / day)
Discharge Pressure	> 2000 psig

2.2 Pipeline Specifications

The purity requirement for the CO_2 exiting the Powerspan unit was the Kinder Morgan pipeline specification used for oil and gas applications. Kinder Morgan is the largest transporter and marketer of CO_2 in the United States. Kinder Morgan provided an updated specification showing proposed quantities, listed in Table 2-1. Note that the concentration of H_2S in this new Kinder Morgan specification is limited to 20 ppm by weight (about 25 ppmv). Also total sulfur is limited to 35 ppm by weight. A specification for a maximum ammonia concentration of 5 ppmv was added.

Table 2-1. Kinder Morgan CO_2 Pipeline Quality Specification

<u>Product</u>	Substance containing at least ninety-five mole percent (95%) of Carbon Dioxide.
Water	Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per MMcf in the vapor phase.
Hydrogen Sulfide	Product shall not contain more than twenty (20) parts per million, by weight, of hydrogen sulfide.
Total Sulfur	Product shall not contain more than thirty-five (35) parts per million, by weight, of total sulfur.
Temperature	Product shall not exceed a temperature of one hundred twenty degrees Fahrenheit. (120°F).
Nitrogen	Product shall not contain more than four mole percent (4%) of nitrogen.
Hydrocarbons	Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed minus twenty degrees Fahrenheit (-20°F).
Oxygen	Product shall not contain more than ten (10) parts per million, by weight, of oxygen.
Other	Product shall not contain more than 0.3 (three tenths) gallons of glycol per MMcf and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

The design and installation [1, 2] of the low pressure and high pressure CO_2 pipeline and handling equipment will follow the U.S. Department of Transportation (DOT) and American Society of Mechanical and Materials Engineering codes.

The U.S. CO_2 pipelines operated at supercritical pressures are regulated by the DOT 49 Code of Federal Regulations (CFR) 195 because in certain conditions it could cause health effects and personal protective equipment (PPE) could be required if in a confined space. In the United States, the pipe design code is ANSI/ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids. In Canada, the Canadian Standards Association CAN/CSA Z662, Oil and Gas Pipeline Systems, applies. The majority of existing CO_2 pipelines are constructed of conventional carbon steel; API grade X65–X80 carbon-manganese steels are common.

In the United States, the construction and operational safety regulations are administered by the DOT's Office of Pipeline Safety. Groups such as the API, the American Gas Association, and the American Society for Testing and Materials have established practices and guidelines for CO_2 pipeline material selection and construction. These well-established regulations and guidelines are adequate for managing CO_2 pipelines.

The 49CFR195 consists of more than 200 pages of technical details regarding the proper design and maintenance of CO_2 pipelines. The information is presented in the following subparts:

- Subpart A, General
- Subpart B, Annual, Accident, and Safety-Related Condition Reporting

- Subpart C, Design Requirements
- Subpart D, Construction
- Subpart E, Pressure Testing
- Subpart F, Operation and Maintenance
- Subpart G, Qualification of Pipeline Personnel
- Subpart H, Corrosion Control

2.3 Pipeline Regulations

The Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates the handling and transportation of hazardous materials, including CO_2 in each of its physical states. The PHMSA ensures that operators know the hazards and manage their assets accordingly. Supercritical CO_2 is regulated under 49CFR195 for the following reasons:

- It can cause rapid suffocation.
- It can cause nervous system damage, frostbite, dizziness and drowsiness.
- Self-contained breathing apparatus and protective clothing might be required by rescue workers.

PHMSA's pipeline safety program shares oversight of assets with authorized state programs because onshore regulation of oil and natural gas production and storage is under the jurisdiction of each state or province. See the 2005 Interstate Oil and Gas Compact Commission (IOGCC) publication *Carbon Capture and Storage: A Regulatory Framework for States—Summary of Recommendations*, Appendix 2 and Appendix 5, for a compendium of current state and provincial regulatory frameworks for CO_2 handling and pipelines [3].

The PHMSA has established a new division to improve the monitoring, evaluation, and documentation of CO_2 handling [4]. This new Program and Performance Evaluation Group will 1) look at CO_2 pipelines and other pipelines using improved monitoring equipment and instrumentation and 2) provide improved information on pipeline risks to enable more informed decisions on regulations, inspection, and enforcement.

The PHMSA recently reported on the condition and age of the regulated U.S. CO_2 assets. Figure 2-3 shows the PHMSA data documenting the years of installation, number of assets, and percentage of total assets. For example, the yellow section indicates that in the 1990s, 794 CO_2 assets, or 22% of the total, were installed in the United States. The data also indicate that 66% of CO_2 assets have been in operation for more than 20 years.

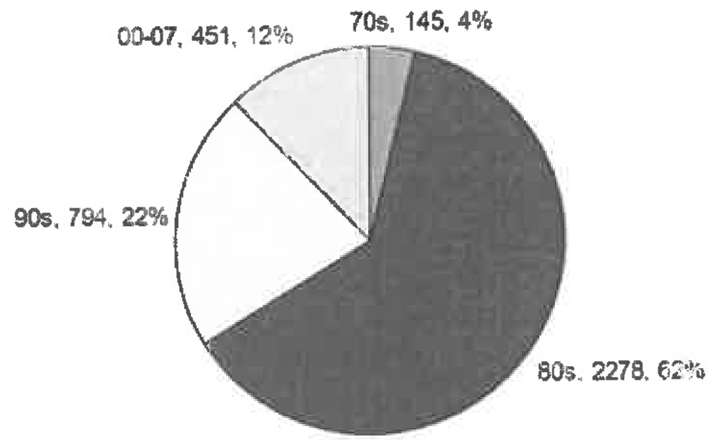


Figure 2-3. Age of regulated carbon dioxide assets [4]

CO_2 pipeline incidents reported by the PHMSA are shown in Figure 2-4. The incidents are divided into five categories–corrosion, equipment malfunction, excavation and third-party damage, material and failed weld, and other causes. The data from the 36 reported incidents indicate that the majority of failures were related to equipment malfunction and human handling errors and not to pipeline corrosion. PHMSA confirmed that there were no CO_2 pipeline failures in the United States [5].

There was an incident in the United States in which a heavy equipment operator penetrated a buried 20-cm diameter (7.9-in) supercritical CO_2 pipeline [6]. The operator suffered non-life-threatening injuries, and the resulting leak was quickly sealed off. The pipeline was isolated, and a new section of pipe was welded in.

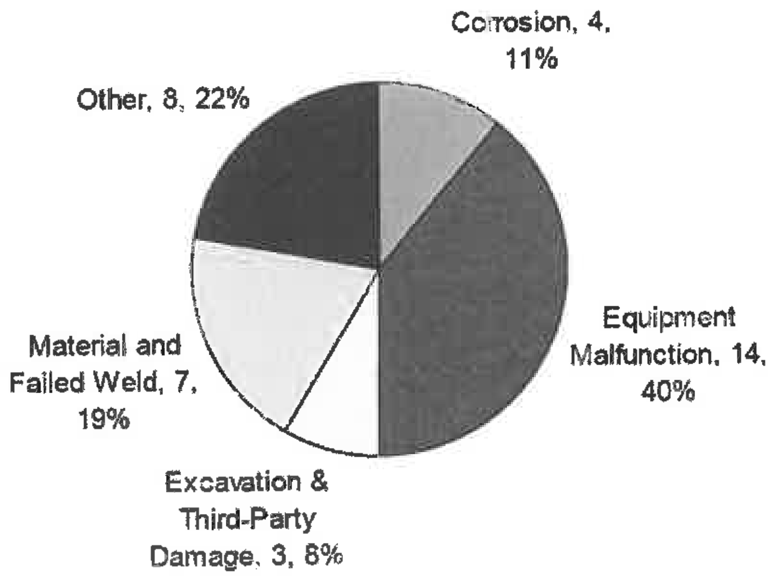


Figure 2-4. Causes of U.S. carbon dioxide pipeline incidents [4]

The Federal Energy Regulatory Commission is the only other federal agency that has natural gas interstate regulatory responsibilities. Presently, it has no legislative authority to regulate interstate CO_2 pipelines. Several unresolved state and federal issues regarding interstate CO_2 pipelines include eminent domain. There is a potential need for a federal authority such as the Federal Energy Regulatory Commission to manage the jurisdiction of these interstate pipelines that will become more prevalent in the future.

3.0 Selection of Suppliers and Engineering Contractor

3.1 Selection of CO_2 Compressor

Three compression approaches were discussed during the initial phase of the project. The approaches were:

1. Compress the CO_2 in the gas and supercritical phases from 50 psig to 2000 psig using a mechanical device such as a multi-stage reciprocating, rotary screw, or centrifugal compressor.
2. Use a combination of gas phase compression, liquefaction, and liquid phase pumping. The CO_2 gas would be compressed to a pressure between 200 and 400 psig, the CO_2 gas would be liquefied, and pumped as a liquid up to 2000 psig with commercially available equipment.
3. Vent the CO_2 produced from the ECO2 unit and purchase commercial compressed CO_2 in larger portable tankers. The industry standard CO_2 is delivered at 350 psig and -20°F.

The first two approaches are explained in Figure 3-1 using the principle of thermodynamic states. Figure 3-1 shows pressure as a function of enthalpy for CO_2. All thermodynamic properties are defined at each location in pressure-enthalpy space. The lower region under the dotted line represents the region where both gas and liquid phases coexist. The region to the left of the dotted line is the liquid phase and the region to the right of the dotted line is the gas phase. The state of CO_2 above the dotted line is typically referred to as a supercritical fluid which is neither a liquid nor gas. The critical condition for CO_2 is 1055 psig and 88°F.

Figure 3-1 shows two very different pathways that start with the CO_2 in a gas phase at a pressure of 0 psig and temperature of 90°F, and finishes in the supercritical region at a pressure of 2500 psig and temperature of 90°F. The "Conventional Option A" pathway is representative of a four-stage intercooled compressor that compresses and cools the CO_2 four times in the gas and finally in the supercritical phase as it moves along the pathway on the right hand side of the dotted line. This pathway enables the CO_2 to be compressed in a state that is safely away from the two phase region that is extremely problematic for industrial compressors.

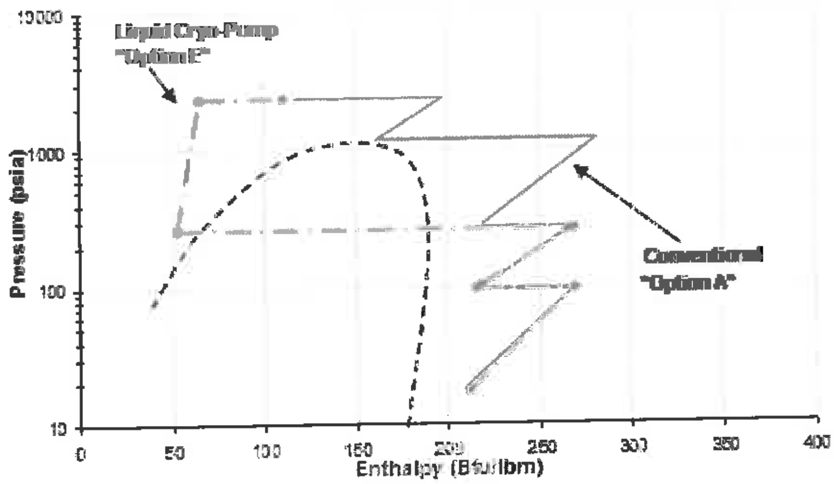


Figure 3-1Two Compression Pathways [7]

The "Liquid Cryo-Pump Option E" is a much different pathway but starts and finishes at exactly the same thermodynamic states as the Conventional Option A. The two pathways start out together with two stages of compression and two intercooling processes up to 300 psig. At this state the two pathways separate and Option E continues to cool the gas phase CO_2 until it completely passes through the two-phase liquid-gas region and into the liquid phase. This process is called liquefaction and is used in several industrial processes for CO_2 and other gases. The liquid CO_2 is compressed up to 2500 psig using a rotating centrifugal or reciprocating pump and then heated up to 90°F to the final supercritical state.

There exist an infinite number of pathways to move from state 1 to state 2 in thermodynamic space. Each theoretical pathway will have its own practical advantages and disadvantages that are in evaluation by the compression industry to optimize compression efficiency, minimize power requirements, and deduce capital and operational costs.

Approach #1 was chosen for evaluation in this report since it is a proven technique for these types of small applications.

Approach #2 has not been demonstrated at these conditions and is recommended as a follow-on project at the Burger plant or another appropriate location.

Approach #3 was ultimately chosen since the CO_2 from the Powerspan unit was not available.

Reciprocating (to move back and forth) piston compression is the most common and traditional technology used to deliver high discharge pressures. This approach uses a crankshaft and rod to drive the pistons within a contained cavity as shown in Figure 3-2. They can be single or multi-staged. Their discharge pressures can range from very low to very high 4500 psig.

Reciprocating CO_2 compressors come in a variety of power range from small units (100 hp – 1000 hp) to large units up to 5000 hp. Higher power requirements typically call for other compression technologies such as multistage rotating axial or centrifugal compressors.

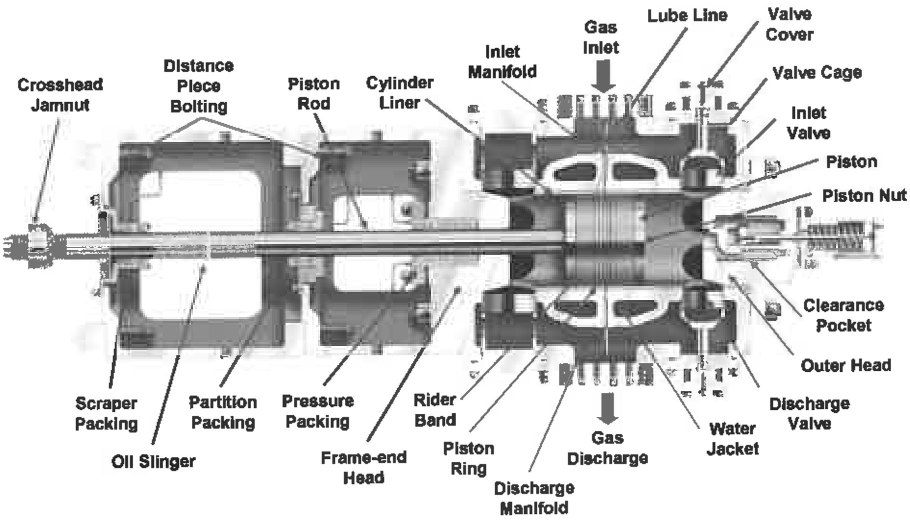


Figure 3-2. Reciprocating Compressor Cylinder Details [8]

The compressors shown in Figures 3-2 and 3-3 are manufactured by Dresser-Rand (U.S.). The piston is moved back and forth by the piston rod. This design compresses the gas on both sides of the piston in the cylinder cavity. Figure 3-3 shows the low pressure gas entering on one side of the cylinder cavity from the inlet manifold and the compressed gas exiting the cylinder cavity on the other side of the piston through the discharge manifold.

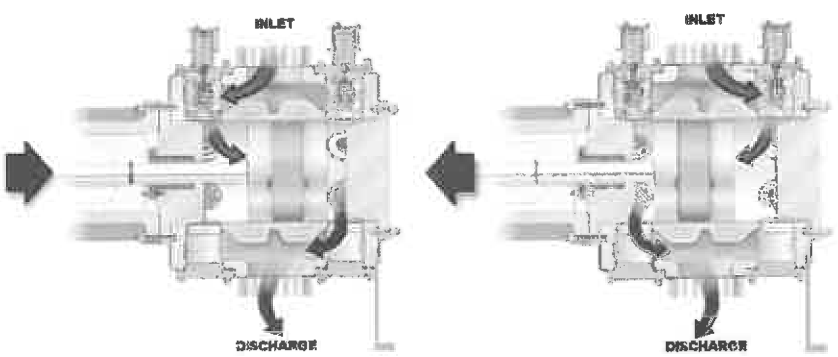


Figure 3-3 Inlet and Exhaust Gas Flow in Cylinder [8]

The high pressure ratio machines required for typical CO_2 compression applications are always multi-staged. An Ariel Corporation (U.S.) four-stage intercooled reciprocating compressor is shown in Figure 3-4. The intercoolers between the inlet and discharge locations for each piston are not shown. This four-stage design will compress CO_2 from ambient conditions to over 2000 psig in pressure increments in the range of 2:1 to 2.4:1.

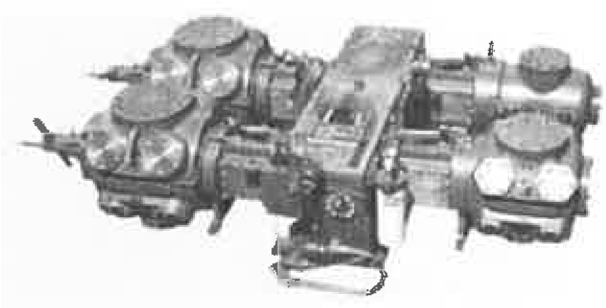


Figure 3-4. Four-Stage Intercooled Reciprocating Compressor [9]

Reciprocating compressors are a common choice for CO_2 EOR applications for the following reasons:

- Flexibility with the pressure ratio, flow capacity and turndown if equipped with variable speed drive.
- Short delivery times since reciprocating compressor packagers maintain a selection of frames and cylinder parts in stock for quick assembly and overhaul.
- Light-weight skid-mounted packages for easy shipping and relocation.
- Familiarity of field operators with these machines and their suppliers.

There are also a number of factors that will limit the use of reciprocating compressors for large CO_2 EOR or sequestration projects. These factors include:

- Size limitations require multiple units.
- Inspections, maintenance, repair and overhaul intensive.
- Slow speed machines require massive structural foundations.
- Capital and operational costs are relatively high.

The major U.S. providers of reciprocating compressors for CO_2 EOR and other industrial applications are Ariel Corporation in Mount Vernon, Ohio for power requirements up to 1000 hp and Dresser-Rand in Olean, NY for power requirements up to 5000 hp.

Ariel Corp. was chosen as the compressor manufacturer based on the estimated power requirement of 100 hp. The technical staff at Ariel Corp. was tremendously supportive of the project and visited the site on several occasions.

3.2 Selection of Packager

A packaging company was required since Ariel Corp. only manufactures compressors. The packaging company provides the following equipment:

- Electric motor or gas fired engine to drive the compressor

- Heavy duty structural steel skid
- Intercoolers and aftercooler
- Lubrication system
- PLC type control system
- Installation and startup technical support

A packager was selected from an Ariel Corp. list of recommended companies in the U.S. Four written bids were evaluated.

The turnkey package costs from the four companies, including the compressor, ranged from $250,000 to $600,000 +/- 15%. The delivery time to site ranged from 30 to 60 weeks with the compressor being the long lead time item.

The site requirements for the compressor package were:

- 480 V, 3 phase, 60 Hz electric source
    - Separate hook up for pre-lube pump, oil cooler, gas cooler, main 100 hp drive motor.
- Oil supply for compressor (30 gallon storage tank is sufficient)
- Gravel or concrete pad
- Potentially small building to cover compressor (some bids required it)
- Onsite piping hook up
- Technical support to install and startup the package.
- Provide training for the First Energy site staff.

3.3 Selection of Engineering Contractor

One engineering firm was selected to provide a design and written cost estimate for the system. In addition two verbal cost estimates were received from other sources. The two verbal cost estimates and one written cost estimate were in the range of $750,000 to $1,200,000, excluding the cost of the compressor package. The time to complete the project was projected to be 30 to 40 weeks from the award of the contract.

The engineering firms considered the project to be within their normal capabilities with no unique technical barriers or risks.

The proposed project which would integrate the Powerspan ECO2 CO2 vent stack with the MRCSP CO2 wellhead consisted of the following:

<u>Compressor and Piping:</u>

The compressor will consist of the following major process areas and support systems:

- One (1) 125 HP motor driven reciprocating 4 stage compressor complete w/ motor driven cooler and suction separators
- The compressor will be located at the ECO2 pilot plant location near the power plant
- Suction piping (heat traced and insulated) from the process outlet connection point to the compressor valve skid
- Discharge piping from the compressor valve skid to the injection well head
- Compressor valve skid
- Interconnecting piping between the valve skid and the compressor
- Vent pipe located adjacent to the crystallizer tent

Electrical Systems

- Tie into the existing 480 VAC power panel in the "Green Room". Breaker and panel modifications (if any) to be supplied by others
- Tie into the existing 120 VAC power panel at the compressor. Breaker and panel modifications (if any) to be supplied by others
- 480 VAC Power distribution panel located at the compressor
- Power Feed to the Well Head
- Heat Trace of the Suction Pipe

Instrumentation / Controls

- Unit Control Panel
- CO_2 monitor
- Pressure and Temperature Transmitters

Miscellaneous Items

- Evacuation Respirators

Engineering Services:

Design covering the compression and associated piping and electrical systems.

- Piping
    - Process gas and vent piping systems
- Structural
    - Support and mounting details

- Concrete
    - Design for all foundations
- Electrical
    - Design for all electrical and instrumentation systems
- Material
    - Expedition Services for Equipment purchased by builder
    - Specification and purchasing of materials supplied by builder

4.0 Summary

The objectives of the report were achieved by reviewing existing literature on CO_2 handling guidelines and regulations, and direct communication with CO_2 compression equipment manufacturers, engineering firms, and multiple site visits.

The Ariel Corporation in Ohio provided the specifications for the CO_2 compressor. The selected compressor was a four-stage reciprocating, air intercooled, horizontal unit driven with 460 volt electric motor. A packaging company was required since Ariel Corporation only manufactures compressors. A solicitation resulted in receiving four detailed proposals from companies that primarily work in the oil and gas industry. The turnkey package costs ranged from $250,000 to $600,000. The delivery time to site ranged from 30 to 60 weeks with the compressor being the long lead time item.

An external engineering firm to design, procure, and install the compressor and piping to the wellhead. A search for appropriate companies resulted in a short list of three organizations. One company was chosen to provide a complete and realistic technical proposal, cost budget, and schedule. The cost estimates from the three engineering companies ranged from $750,000 to $1,200,000, excluding the compressor package. The time to complete the project was projected to be 30 to 40 weeks from the award of the contract.

The engineering firms considered the project to be within their normal capabilities with no unique technical barriers or risks.

5.0 References

1. *Regulation and Permitting of Carbon Dioxide Transport and Geologic Sequestration.* EPRI, Palo Alto, CA: 2008. 1016854.
2. *Carbon Dioxide Compression and Transportation.* EPRI, Palo Alto, CA: 2008. 1016794.
3. *Carbon Capture and Storage: A Regulatory Framework for States—Summary of Recommendations.* Interstate Oil and Gas Compact Commission, Oklahoma City, OK. January 2005. Available for purchase from http://www.iogcc.state.ok.us/carbon-sequestration (accessed December 9, 2008).

4. J. Kadnar. "Experience in CO_2 Transportation via Pipeline," presented at International Energy Agency CCS Regulators' Network webcast, July 2008. Available from http://www.iea.org/textbase/work/2008/ccs/Kadnar.pdf (accessed November 26, 2008).
5. J. Kadnar, U.S. Department of Transportation, Pipeline & Hazardous Material Safety Administration, unpublished data, October 2008.
6. A. Oosterkamp and J. Ramsen. *State-of-the-Art Overview of CO2 Pipeline Transport with Relevance to Offshore Pipelines*. Polytec, Haugesund, Norway: January 2008. Report No. POL-O-2007-138-A.
7. J. J. Moore, M. G. Nored, R. S. Gernentz, and K. Brun. *Novel Concepts for the Compression of Large Volumes of Carbon Dioxide*. Southwest Research Institute, San Antonio, TX: June 2007. Project No. 18.11919. Final Report to U.S. Department of Energy.
8. H. Miller. "Carbon Dioxide Compression," presented by Dresser-Rand to Southwest Research Institute and EPRI, San Antonio, TX, June 25, 2008.
9. Ariel Corporation, Mountain View, OH, unpublished data, 2008.

APPENDIX G

PUBLIC OUTREACH MATERIALS

Sample Outreach Planning Matrix for Submitting the UIC Permit Application

Example Outreach Planning Matrix for Filing the Permit (Assumes Permit Filed Mid-November, 2007; Notice of Availability May-June, 2008; Final Permit July, 2008)

TIME FRAME	STAKEHOLDER	OUTREACH OBJECTIVE	OUTREACH APPROACH	NEEDED MATERIALS	RESPONSIBILITY
Ongoing	EPA regulatory contacts	-Clarify regulatory schedule - Coordinate with regulators to design public involvement and prepare for public meeting(s)	- In-person and telephone discussions	Dates of notice and comment periods	Battelle to initiate
Ongoing	FirstEnergy employees - General Employees - Executive Mgt - Government Relations - Media/ Communication	- Inform /build sense of ownership, work to make "ambassadors" for project	Briefings and information materials as needed	Briefing packet: - Updated MRCSP fact sheet - Updated power point presentation - Other?	- Battelle to update web and information packet as requested
January -March	Key local officials: - Name 1 - Name 2	Respond to questions, build awareness and understanding	- Face to face briefing if needed	- Briefing packet as above - Technical briefing, if needed	
January-March	Key State Agency Officials (list): -- --	Respond to questions, build awareness and understanding	- Face to face briefing	- Briefing packet, as above? - Other?	FirstEnergy
January	Governor's Office	Respond to questions, build awareness and understanding		- Briefing packet - Other?	FirstEnergy
January –March	Key State legislators: (List): --	Respond to questions, build awareness and understanding	- Face to face briefing	- Briefing packet? - Other?	FirstEnergy

TIME FRAME	STAKEHOLDER	OUTREACH OBJECTIVE	OUTREACH APPROACH	NEEDED MATERIALS	RESPONSIBILITY
January-March	State and federal legislators and aides: (list): -- --	Respond to questions, build awareness and understanding	Face to face meetings with legislator and/or staff	- Briefing packet? - Other?	FirstEnergy
On going as needed	Media	- Low key, respond to enquiries - Potentially more aggressive plan prior to public hearing/ informational meeting	Respond to media	Talking points? Media release?	Battelle, FirstEnergy as appropriate (Media release needs DOE prior approval)
February-April	Influential plant neighbors, business and environmental organizations	Inform, seek feedback	- Telephone call or meeting	- Briefing package - In-person meeting or telephone call, as needed	
April-May and ongoing throughout permitting review process	Adjacent stakeholders Questions: - Are these stakeholders notified individually by Ohio EPA? - What is the radius for notification? (1/4 mile or ½ mile radius)	Ensure early identification of potential permit issues	If needed: Provide information/ opportunity for individual pre-permit discussion if needed	If needed: - MRCSP Fact Sheet - One-on one discussion	FirstEnergy to monitor situation
May-June Meeting planning to begin March	General public	Provide opportunity for informal discussion and learning, prior to issuance of Notice of Availability and Ohio EPA public hearing.	Informational meeting	Posters, handouts	Battelle to develop information materials and collaborate with FirstEnergy on meeting planning and implementation

Project Factsheet

MANAGING CLIMATE CHANGE AND SECURING A FUTURE FOR THE MIDWEST'S INDUSTRIAL BASE

MRCSP
MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP

Carbon Dioxide Storage Field Demonstration at FirstEnergy's R.E. Burger Plant: Project Overview

Purpose of the Demonstration

The Midwest Regional Carbon Sequestration Partnership (MRCSP), led by Battelle under contract to the U.S. Department of Energy, is conducting several field demonstrations in its Midwestern region to help assess the effectiveness of storing carbon dioxide deep underground.

The concept of storing carbon dioxide underground is often referred to as sequestration, i.e. to isolate or keep apart. Since rock formations can be considered geologic reservoirs, scientists refer to this concept as geologic sequestration. FirstEnergy, a member of the MRCSP, has volunteered its R.E. Burger Plant in Shadyside, Ohio, as one of the field demonstration locations.

The type of demonstration being conducted at the Burger Plant site is an essential step in proving the feasibility of geologic sequestration. When proven to be safe and practical, geologic sequestration could help reduce carbon dioxide emissions to the atmosphere. Geologic sequestration also could be economically important to Ohio and other Midwestern states that depend heavily on coal for their energy needs.

What Is Geologic Sequestration?

Geologic sequestration is part of a broader approach to reducing global carbon dioxide emissions. It first involves capturing carbon dioxide from the emissions of power plants and other industrial facilities. The carbon dioxide is then injected through a deep well into carefully chosen geologic formations. There, the carbon dioxide is permanently stored in rock formations thousands of feet below drinking water supplies. These rock formations are similar to those that have stored natural gas and oil for millions of years. Suitable candidate geologic formations for geologic sequestration include saline or brine (saltwater) reservoirs, depleted oil and gas fields, or coal beds that are too thin or deep to be cost effectively mined. The Burger Plant demonstration will involve injection into a brine reservoir. This will be located between 4,000-

7,000 feet below the surface and well below drinking water supplies, which are about 100 feet deep in this region.

Activities Underway

There are several stages of activities that occur during the project. They include: initial planning and preliminary assessment; site characterization studies; approval of a permit to inject by the Ohio Environmental Protection Agency (OEPA); carbon dioxide well injection; monitoring; and closing or capping the well after the research is completed.

July, 2006 Seismic Survey

Based on the findings of the preliminary assessment and planning, a site-specific characterization effort was initiated in the summer of 2006. The purpose was to confirm the geologic features of the site and determine the suitability of the site for injecting carbon dioxide. This included a seismic survey of the area and drilling and testing in a deep well.

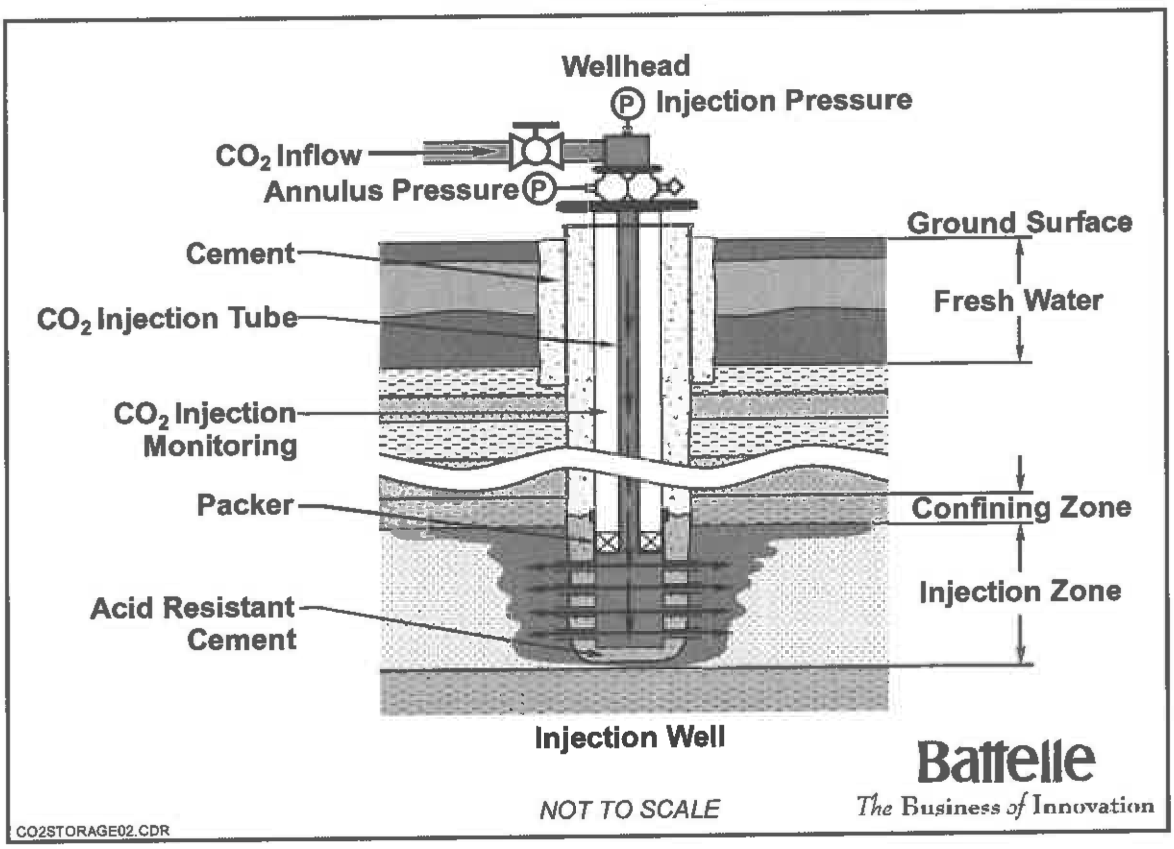
A seismic survey was conducted in and around the proposed well location in July of that year. Engineers and scientists developed below-surface images by placing sensitive microphones on the ground in an area around the Burger Plant. They listened to the echoing vibrations, which were transmitted by cable to a truck where they were recorded. The results of the survey have been used to determine the rock properties, including continuity of the geologic layers and presence or absence of faulting in the area.

Drilling Rig Setup at the Burger Plant

Based on the survey results, the next step was to drill and test a deep well. Appropriate drilling permits were obtained from state regulators and, in December 2006, the project team worked with a contractor to set up a drilling rig at the demonstration site and construct the well. The well was drilled to a depth of almost 8,400 feet, with a 7-inch diameter steel casing installed to a depth of over 5,700 feet. The project team has been conducting reservoir tests in the well, as needed. These tests have provided more information about the nature and strength of the underground rock and indicate the maximum pressure that the rocks can withstand if injection occurs.

Now that these site characterization studies have confirmed that the location is a good candidate for injection, the study team has completed an application for an experimental injection permit, developed a plan for monitoring the operation, and designed the injection system. A variety of controls are written into the drilling and injection permits, which are mandated to ensure the safety and protection of underground drinking water supplies. The draft injection permit is expected to be available for public review and comment in early spring, 2008. Injection can begin only after Ohio EPA has addressed public comments and approved the permit.

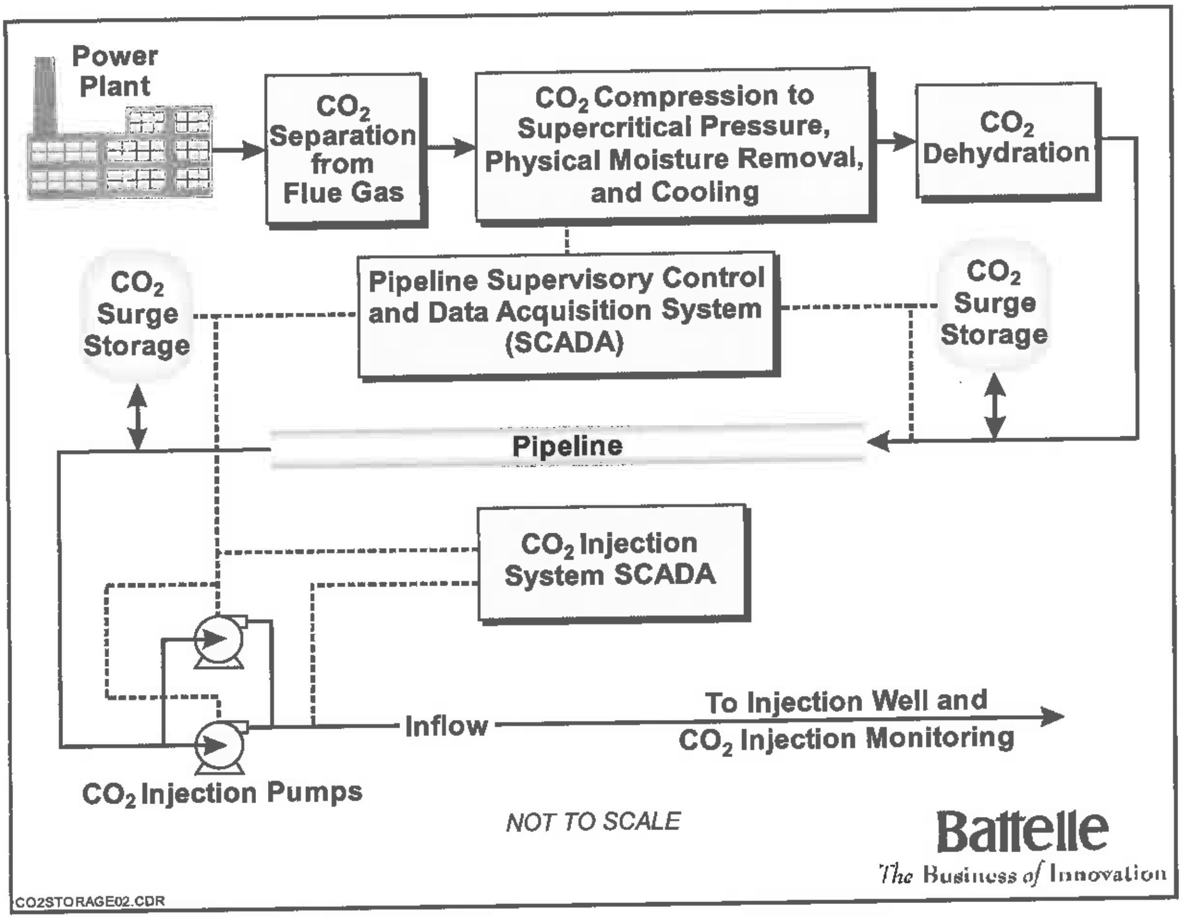
Drilling Activity at the Burger Plant Demonstration Well



Injection Well Design and Protective Mechanisms

The Burger Plant demonstration is not a commercial-sized project but a very small-scale test. As a result, the field test will inject only about 3,000 tons of carbon dioxide at the site over a period of several months. This is about the same amount that would be produced in two days by operations at the Burger Plant.

As part of the demonstration, extensive monitoring will be conducted both during and after the injection phase. Once the carbon dioxide injection is finished, the monitoring will continue until the demonstration is complete. At the end of the project, the MRCSP research team will review and evaluate the results of the demonstration, and the well will be plugged or capped.



Geologic Sequestration System Components

How can I Get More Information or Provide Input?

If you have questions, want more information, or wish to be put on a mailing list for updates, please contact: **FirstEnergy's R.E. Burger Plant at 740-671-1888.**

Questions or comments may also be sent by email to Dr. Neeraj Gupta, Battelle Manager for the MRCSP Field Demonstration Projects at gupta@battelle.org or to Traci Rodosta, USDOE Project Manager at Traci.Rodosta@netl.doe.gov.

Information on overall MRCSP activities is available on the website at www.mrcsp.org. The web site includes a mailing list and an interactive function that allows you to submit comments and questions to the MRCSP research team. Periodically, the MRCSP team will post responses to questions and comments received. Your comments and questions are valuable in helping us understand and address your concerns and information needs.

Ohio EPA News Release for Public Meeting

State of Ohio Environmental Protection Agency

PUBLIC INTEREST CENTER
P.O. Box 1049, 50 W. Town St., Suite 700
Columbus, OH 43216-1049
Tele: (614) 644-2160 Fax: (614) 644-2737

News Release

FOR RELEASE: May 27, 2008

CONTACT: Heather Lauer, (614) 644-2160

Ohio EPA to Accept Comments About Carbon Sequestration Project

Ohio EPA will hold an information session and public hearing on June 24 regarding a draft permit that would allow FirstEnergy to test the feasibility of injecting carbon dioxide deep into the ground in an experimental well at the Burger Power Plant in Shadyside. FirstEnergy is managing the project in partnership with Battelle.

The information session and public hearing are at 6 p.m. at the Shadyside High School, Multipurpose Room, 3890 Lincoln Ave., Shadyside.

The draft permit explains terms of how the well will be used. Ohio EPA's deep well regulations are designed to protect underground sources of drinking water so they don't become contaminated by the injected material. This is one experimental technology seen as promising in capturing carbon dioxide from coal-burning power plants.

In order for the carbon dioxide to be sequestered, or stored indefinitely, it must be heated under pressure to the point that it has properties of both a gas and liquid. Once it reaches critical phase, it would be injected into three different rock formations: The 8,207-8,274-foot deep Clinton sandstone; the 6,734 to 7,470-foot deep Salina formation and the 5,923 to 5,954-foot deep Oriskany sandstone.

"In the fight against global warming, it is imperative that we find ways to limit carbon dioxide emissions," said Ohio EPA Director Chris Korleski. "I am excited about the potential opportunities that carbon sequestration could provide in the future, and am encouraged that Ohio is providing a home for cutting edge research."

Written comments about the draft permit may be submitted at the hearing or mailed to Ohio EPA, Division of Drinking and Ground Waters, Attn: UIC Section Supervisor, P.O. Box 1049, Columbus, Ohio 43216-1049. All comments received on or before Monday, July 7, 2008, will be considered prior to the final decision on issuance of the permit.

-more-

People who wish to receive copies of fact sheets and other information about the permit may contact Ohio EPA, Division of Drinking and Ground Waters, P.O. Box 1049, Columbus, Ohio 43216-1049, Attn: E. Charles Lowe, (614) 644-2752. Copies of the draft permit may be inspected at the Shadyside Public Library of Belmont County, 4300 Central Avenue, Shadyside; at the Ohio EPA Southeast District Office, 2195 Front Street, Logan, OH, (740) 385-8501; or at Ohio EPA, Central Office, 50 W. Town St., Columbus, OH, by first contacting E. Charles Lowe (614) 644-2752.

-30-

http://www.epa.state.oh.us

Summary of Issues Raised and Lessons Learned at the Public Meeting

Summary of Questions Asked and Main Themes
Ohio EPA Information Session & Public Hearing –
FirstEnergy Underground Injection Control Permit for CO_2 storage at Burger Plant

Date: Tuesday, June 24, 2008 6:00 p.m.
Location: Shadyside High School, Shadyside, Ohio

Attendance: 15 - 20 of which about 6 were local citizens and others were policy makers or affiliated with interested companies.

<u>Q/A Discussion</u> – Questions asked

1. What happens when the experiment is over? Will there be future injections?

2. How much of a watchdog is Ohio EPA?

3. Will the inspections described be announced or can there be unannounced inspections?

4. What did the geological surveys use to select the FE site encompass?

5. How do you keep the CO_2 from leaking into our drinking water?

6. Is there currently a pipeline connected to the injection well?

7. The pipe that was cemented in – where does that go? Is there a pipe bringing CO_2 in from the plant?

8. When the well was drilled, how did they get around/through the drinking water? Is drinking water affected? If not, how was it isolated?

9. What kind of contingency plans are there for people in the neighborhood if something goes wrong? Leakage?

10. You talked about the seven areas of MRCSP – are there other projects going on in the other areas?

11. What keeps the CO_2 from making its way back up to the water table?

12. What happens to the CO_2? Does it stay there? Does it break down?

13. How do you keep the CO_2 supercritical? What kind of pressure? Will it maintain that pressure in the rock formation? What is the temperature of the liquid?

14. What do you do to maintain the well head pressure so it doesn't come back up? How much do you expect to pump in? How long will it take to pump that amount? What happens if the power goes out – will the valve turn off?

15. Where is the CO_2 coming from?

16. How far will it spread horizontally? If you hooked it up to the power plant? Will there be test wells? *(I think he meant monitoring wells.)* (Is there no limit to how far…?)

17. What's the bigger goal if this is successful? Would it be around here? Is there a goal for the percent of CO_2 from power plants to be put in wells?

18. If the money runs out, what happens to this project (this well)?

19. What are the chances of other drilling activities drilling into the stored CO_2?

20. How was the concern about local residences addressed? How could a project be placed so close to residences? (Later discussion expanded on this concern: why was AOR only ¼ mile radius when she and other residents are ½ mile away).

21. I still don't understand why this is being done near homes. I see the work and I understand why testing needs to be done, but would it be feasible to move this somewhere else (away from residences)?

22. The seismic studies – did they test seismic activity where it is injected? ("seismic activity" seemed to reference the potential for creating seismic activity or earthquakes)

23. How did this get going? Did FE and Battelle just work with OEPA?

24. OEPA accused of being hypocritical (not commenter's word but note-taker's interpretation of the comment) – the questioner asked how OEPA could be allowing injection permits so close to residences when the agency is spending so much time and effort telling people how to protect their source water – including removing oil chains from the ground and other items that might leach into drinking water. "You're supposed to educate people – EPA has an image of helping people become green."

25. My other concern is the old coal mine down there. (*In response to OEPA comment, it appears that the concern about the coal mine is that it harmed drinking water supplies*).

26. When the test is done, can we rest assured this is not going to be a functioning CO_2 well?

NOTE: THREE UNDERLYING THEMES/CONCERNS WHICH IS IMPORTANT TO ADDRESS

1) Project is too close to homes
2) Do not want a permanent project
3) Concern that Ohio EPA oversight may not be sufficiently rigorous

Appendix U_1:

AEP Comments: Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

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,

John M. McManus
Vice President - Environmental Services
American Electric Power

cc: Office of Information and Regulatory Affairs, OMB
Attn: Desk Officer for EPA
725 17th Street. NW,
Washington, D.C. 20503

Mr. Kevin Culligan, U.S. EPA (by email)
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 less than one page 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.

[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

[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;

[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.

---

[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.

---

[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.

---

[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:

---

[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

---

[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. 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

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]

---

[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]

"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. <u>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</u>

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

[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 <u>any</u> 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]

[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/AP372756916 11b44ba83bbeda4d63725f2.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

---

[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

[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.

---

[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*

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. EPA's literature review does not demonstrate that CCS is the BSER

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

[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

[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 'nth-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*

[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 Nth plant technology in some of the plant, but that use large, new, critical subsystems elsewhere should also be considered FOAK.*"[166]

[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 FOAK: Integrated CCS
Tx Clean Energy Project (Summit)	IGCC/Polygen with CCS/EOR	400 MWg 130-212 MWn	$1.73 billion[170]	$3.8 billion	---	---	---	FOAK: IGCC/Polygen FOAK: Integrated CCS[171]
Hydrogen Energy California	IGCC/Polygen with CCS/EOR	405-431 MWg 151-266 MWn[172]	$4 billion[173]	---	---	---	---	FOAK: IGCC/Polygen FOAK: Integrated CCS
Boundary Dam[174] (SaskPower)	PC (rebuild) with CCS/EOR	160 MWg 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 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

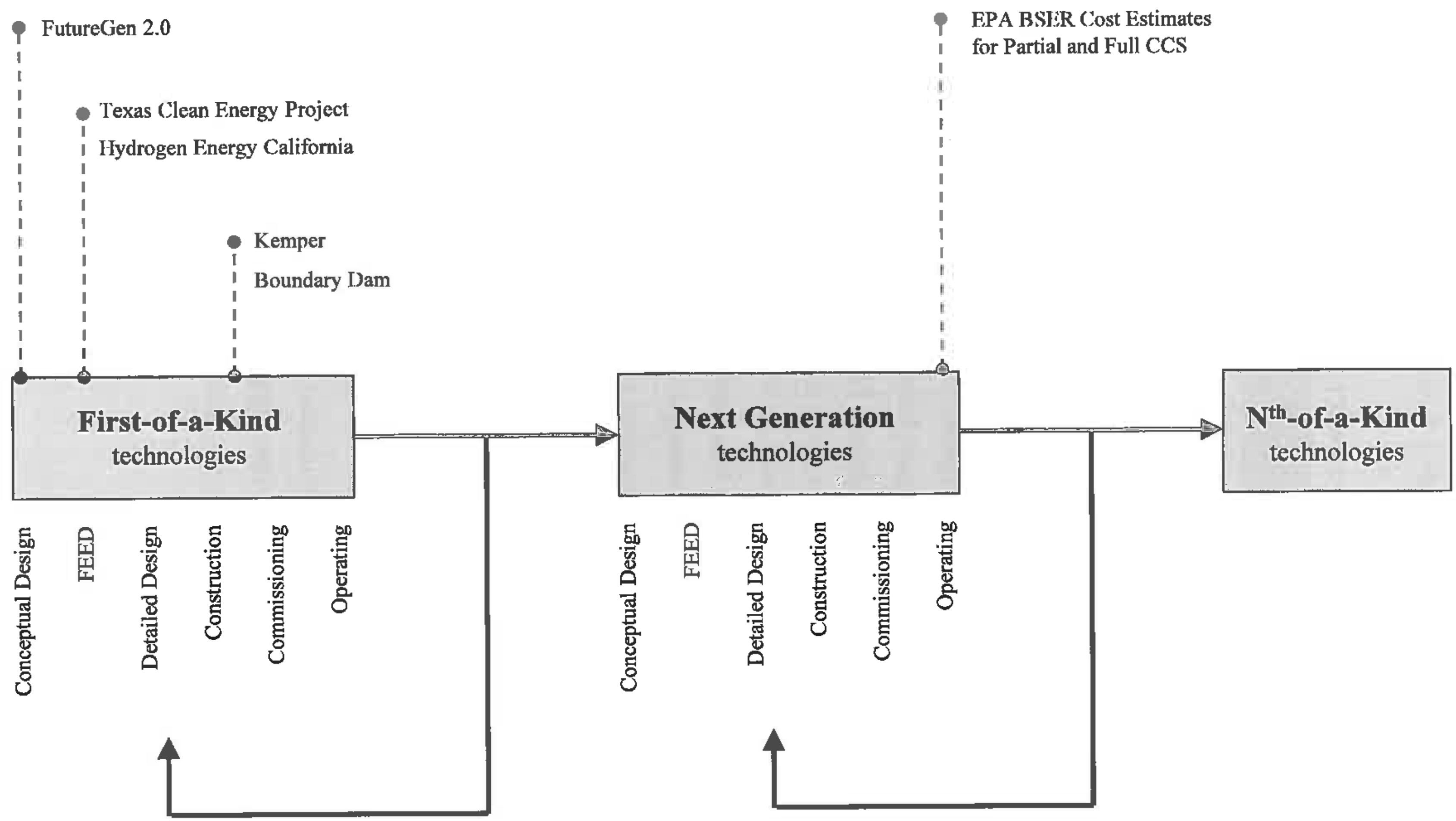
When compared to cost of actual projects and the assessments from organizations that are much more directly involved CCS development, EPA's cost assessment misses the mark by a very wide margin both in terms of the magnitude of costs involved and their conclusions on the current state of CCS development. 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,

[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

[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. <u>The cost of commercial-scale CCS remains a significant unknown</u>

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. <u>The energy required to power CCS systems is large and represents a significant development challenge</u>

The energy demand and parasitic load to power CCS systems is significant. As noted by the Department of Energy:

[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.

---

[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)

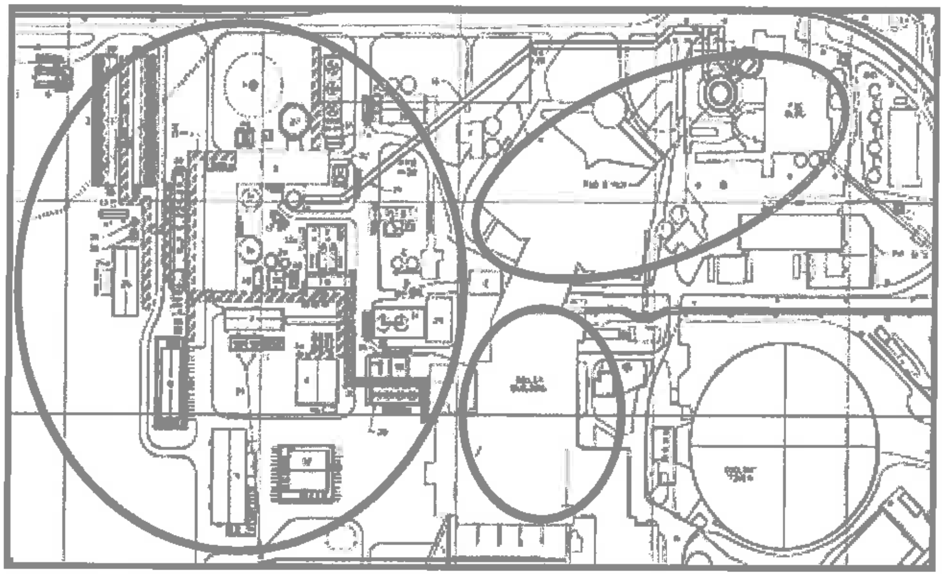
- Capture System Design Specifications: Certain capture systems have stringent process chemistry requirements that demand pristine flue gas conditions that in some cases are well beyond the capability of state-of-the-art flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems. 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. *EPA has ignored property rights issues that are barriers to the adequate demonstration and development of CCS*

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%20ETIP%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?

[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

[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. *EPA ignores interstate and comingling issues that are barriers to the adequate demonstration and development of CCS*

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. *Uncertainties regarding the applicability of RCRA regulations remain 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 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. Geologic storage may be the greatest challenge to the adequate demonstration and development of CCS

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 <u>not</u> 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. Enhanced oil recovery offers no guarantee as being available or willing to support CO_2 capture processes from coal-based generating units

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.

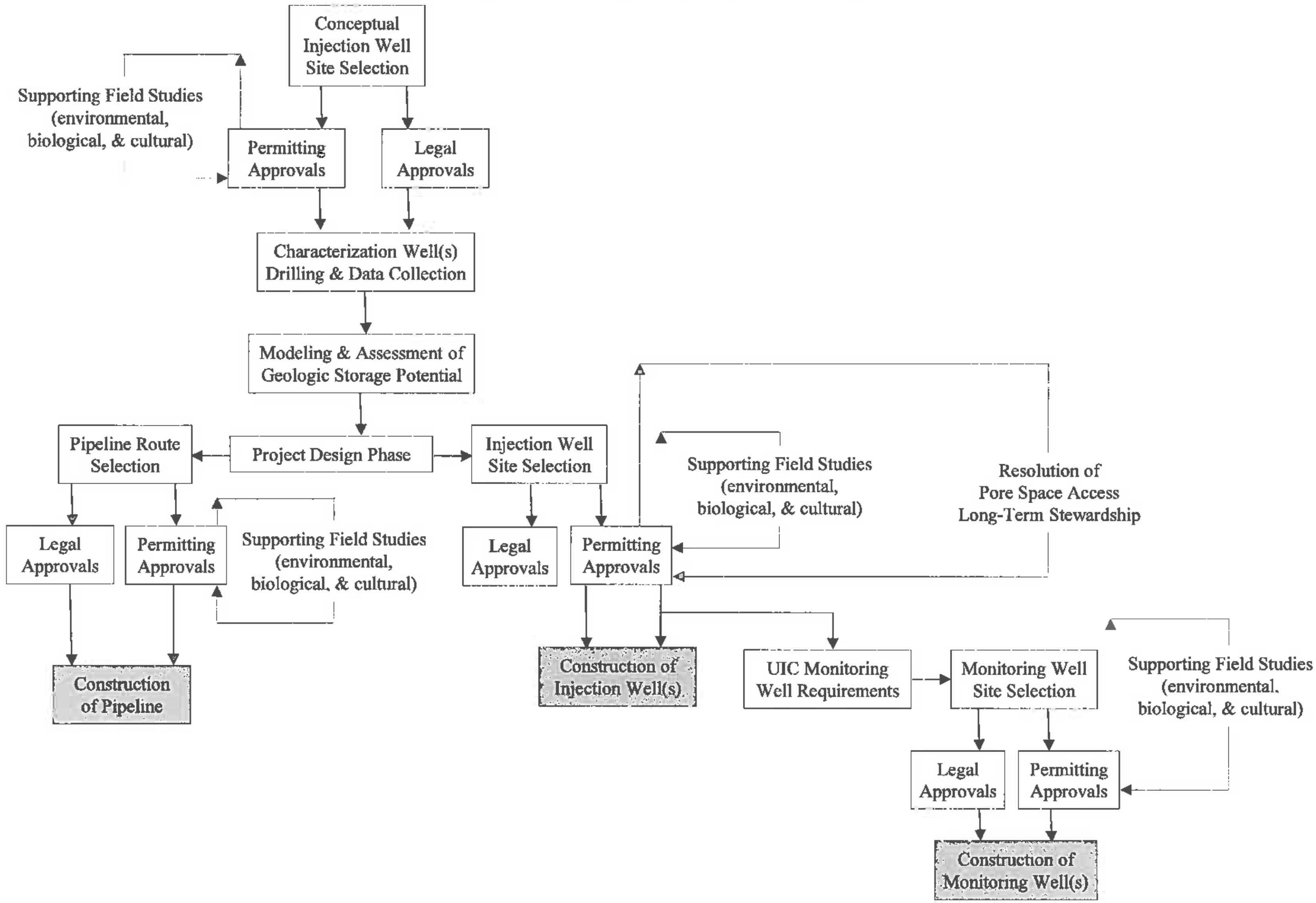
9. Extensive permitting requirements introduces significant schedule and financial challenges to the development of CCS technologies

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*

---

[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 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

---

[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

---

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**:

---

[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]

[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 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 "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 "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 only one passing reference 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 **nine** international projects and databases listing **dozens** 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 **zero** 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 Commenced operations in 2009
Lunen Power Plant (Germany) [309]	"Most Efficient...Coal-fired Power Plant in Europe) Commenced operations in December, 2013
Manjung Plant (Malaysia) [310]	1,000 MW ultra-supercritical plant Commence Construction in 2014 /Operations in 2017
Isogo Plant[311] (Japan)	600 MW ultra-supercritical plant Commenced Operation in 2009
Niederaussem Power Station (Germany) [312]	965 MW ultra-supercritical plant Commenced operation in 2002
Nordjylland Power Plant (Denmark) [313]	384 MW ultra-supercritical plant 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.

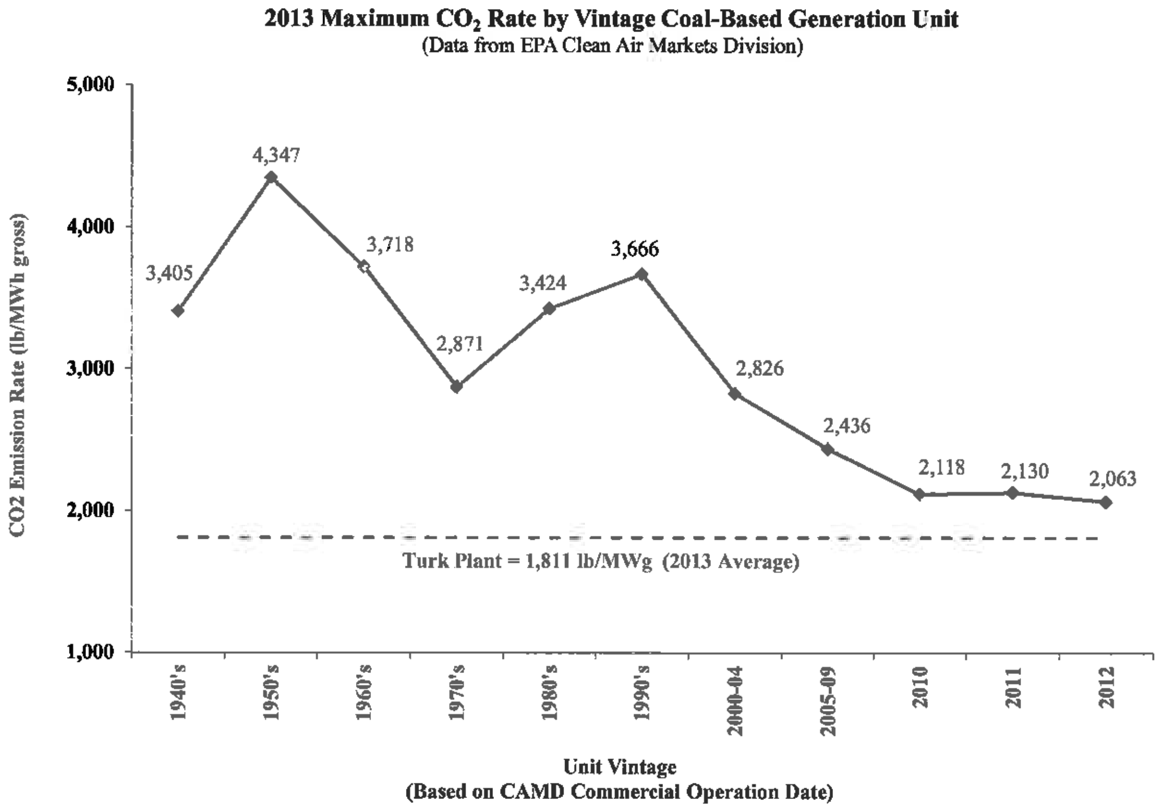
2. The development of highly efficient generation technologies continues to provide meaningful emission reductions

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 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.

[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 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 Dry-Feed	Oxygen-Blown	none
Fluidized-Bed	KBR Transport	Dry-Feed	Air-Blown Oxygen-Blown	Kemper
Fluidized-Bed	High Temp Winkler	Dry-Feed	Air-Blown Oxygen-Blown	none
Fluidized-Bed	U-GAS	Dry-Feed	Air-Blown 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