FEASIBILITY REPORT

For a State Plan under EPA's Clean Air Act Section 111(d) Rule
Regulating Carbon Dioxide Emissions from Existing
Fossil Fuel-Fired Electric Generating Units

Pursuant to
W.Va. Code § 22-5-20

Prepared by the
West Virginia Department of Environmental Protection

April 20, 2016

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Abbreviations and Acronyms

111(d) rule	Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units [80 Federal Register 64662, October 23, 2015] under § 111(d) of the 1990 CAA, 40 CFR 60, Subpart UUUU
AEP	American Electric Power
APCo	Appalachian Power Company
AMD	Acid Mine Drainage
BAU	Business-As-Usual energy modeling scenario assuming no EPA 111(d) rule
BSER	Best System of Emission Reductions
CAA	1990 Clean Air Act: 42 U.S.C.A. §§ 7401 to 7671q
CBER	Center for Business and Economic Research at Marshall University
CCS	Carbon Capture and Storage (or Sequestration)
CEIP	Clean Energy Incentive Program
CEMS	Continuous Emissions Monitoring System
CHP	Combined Heat and Power
CO_2	Carbon Dioxide, a greenhouse gas
COP	Conference of the Parties
CPP	Clean Power Plan refers to the collection of final and proposed EPA rules and policies aimed at reducing carbon pollution from new and existing fossil fuel-fired EGUs under §111(d) of the 1990 CAA
DAQ	Division of Air Quality within WVDEP
DIEM	Dynamic Integrated Economy/Energy/Emissions Model
EE	Energy Efficiency
ERC	Emission Rate Credit
EGU	Electricity Generating Unit
EIA	U.S. Energy Information Administration
EM&V	Evaluation, Measurement and Verification
EMSI	Economic Modeling Specialists, Inc
EPA	United States Environmental Protection Agency

EVA	Energy Ventures Analysis
FE	First Energy
FERC	Federal Energy Regulatory Commission
FR	Federal Register
FRR	Fixed Resource Requirement
FTE	Full-Time Equivalent
GDP	Gross Domestic Product
GWh	Gigawatts hours is equal to one billion watts of electricity used continuously for one hour
HB2004	House Bill 2004 amended West Virginia Code § 22-5-20
IGCC	Integrated Gasification Combined Cycle
INDC	Individual Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
IOGAWV	Independent Oil and Gas Association of West Virginia, Inc.
IRP	Integrated Resource Plan
lb CO_2/MWh	Pounds of CO_2 per Megawatt-hour
lb CO_2/MWh gross	Pounds of CO_2 per Megawatt-hour, including all electricity produced by a unit
lb CO_2/MWh net	Pounds of CO_2 per Megawatt-hour, excluding the generation amount of electricity that a unit uses to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices
LNG	Liquefied Natural Gas
LSE	Load-Serving Entity
mcf	Thousand cubic feet, as in volume of natural gas
MEA	Morgantown Energy Associates
MMBtu	Million British Thermal Units
MW	Megawatt, a unit for measuring power that is equivalent to one million watts
MWh	Megawatts hours is equal to one million watts of electricity used continuously for one hour

NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle fossil fuel-fired power plant
NSC	New Source Complement
NSPS	New Source Performance Standard; established by EPA at 40 CFR 60
PSD	Prevention of Significant Deterioration
PJM	PJM Interconnection, Inc., RTO that operates the grid for West Virginia's region
PURPA	Public Utility Regulatory Policies Act
RE	Renewable Energy
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RSV	Reliability Safety Valve
RTO	Regional Transmission Organization
SCPC	Supercritical Pulverized Coal
UNFCCC	United Nations Framework Convention on Climate Change
UMWA	United Mine Workers of America
U.S.	United States
WVDEP	West Virginia Department of Environmental Protection
WVONGA	West Virginia Oil and Natural Gas Association
WV PSC	West Virginia Public Service Commission
WVU	West Virginia University

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I. Introduction

In 2015, the West Virginia Legislature adopted House Bill 2004 (HB2004) which amended West Virginia Code § 22-5-20 to, among other things, require the West Virginia Department of Environmental Protection (WVDEP) to:

- Obtain prior legislative approval of any West Virginia state plan proposed to be submitted to the United States Environmental Protection Agency (EPA) for regulation of carbon dioxide emissions from existing fossil fuel-fired electric generating units pursuant to an EPA regulation that was anticipated to be promulgated under Section 111(d) of the federal Clean Air Act;

- Conduct a comprehensive analysis of the impact of a state plan under the anticipated EPA section 111(d) rule, addressing, at a minimum, eleven factors identified by the Legislature;

- Make two findings as to the feasibility of a state plan under the EPA's 111(d) rule, based on this comprehensive analysis;

- Recommend, as part of the comprehensive analysis, any changes to state law necessary for the development of a state plan under the EPA's 111(d) rule; and,

- Submit a report of the findings of the comprehensive analysis and feasibility determinations to the Legislature within one hundred eighty (180) days after EPA finalized its 111(d) rule.

EPA finalized its 111(d) rule on October 23, 2015. Thus, April 20, 2016 is the deadline for WVDEP's submission of the report required by HB2004. This deadline is not affected by the stay of EPA's 111(d) rule the United States Supreme Court granted on February 9, 2016 or the modifications made to W.Va. Code § 22-5-20 by the adoption of Senate Bill 691 in 2016.

Over 95% of the electric power generated in West Virginia comes from coal. Coal-fired power is a significant part of the state's economic base. West Virginia has historically produced about two and a half times its own power needs, with the excess being exported to other states via the nation's electric grid. However, coal produces the highest carbon dioxide emissions of any source of fuel for generation of electricity. Accordingly, the EPA's 111(d) rule targeting these emissions, in combination with other federal environmental regulations and the forces of a changing energy market place, can be expected to have a profound impact on West Virginia's power industry, coal industry and overall economy.

As a starting point for this feasibility report, three important observations about the charge the Legislature gave the WVDEP in HB2004 must be made. First, in assessing the feasibility of and impact from a state 111(d) plan, the analysis must be based on a state plan that complies with the EPA rule. Necessarily this means that the WVDEP's comprehensive analysis must focus on a plan that is capable of receiving EPA approval. This focus should not be misconstrued as WVDEP's acceptance of, approval of or acquiescence in the EPA's 111(d) rule. The WVDEP submitted very extensive comments to the EPA during the comment period on EPA's 111(d) rule proposal in which WVDEP voiced opposition to the proposed rule on a wide variety of legal, technical and practical grounds. Nearly all of the WVDEP's objections to the proposed 111(d) rule apply with equal force to the version of this rule that EPA finalized on October, 2015. In particular, the WVDEP believes the EPA's 111(d) rule is unlawful for many reasons and, if the court challenges to it are properly decided, the rule will be thrown out. However, to comply with HB2004, the WVDEP must assess the impact of a state plan that complies with the EPA's rule as if this rule is legal.

Second, a distinction must be made between the impact of a West Virginia state plan and the impact from national implementation of EPA's 111(d) rule. If EPA's rule survives the legal challenges, there are forty-six other states[1] that must either develop a state plan or face the imposition of an EPA-developed federal plan. Decisions these other states and the EPA make are beyond the control of the WVDEP or the West Virginia Legislature. These decisions will impact the market for the West Virginia-mined coal that is currently being burned for power in those states as well as the market for West Virginia-produced coal-fired power that is used in other states. According to the federal Energy Information Administration (EIA), from 2010 through 2014, only 15% of the coal produced in West Virginia was burned at instate power plants, 55% went to other states, and 30% was exported. The 55% of West Virginia coal production that goes to other states will be impacted by the state plan decisions made by those states.[2] The 30% that is exported may be impacted by the carbon emissions reduction plans other countries implement pursuant to the recent Paris climate agreement. The national impact of the 111(d) rule may make the carbon-intense power West Virginia currently produces and exports to other states via the grid less competitive in regional power markets. Decisions other states may make to favor other fuel sources or renewable energy or to reduce demand for electricity through imposition of energy efficiency measures will also impact the market for West Virginia-produced power.

Importantly, a West Virginia state plan only deals with West Virginia power producers. Accordingly, the impact of a West Virginia state plan on state coal production is limited to the 15% of our coal production that is consumed in the state. Consistent with the direction given in HB2004 to analyze and assess the feasibility of a state plan, the analysis WVDEP presents in this report focuses primarily on the effects of West Virginia's state plan.

Third, the deadline for submission of this report comes at a time when analyses which should be taken into account in considering state plan options are still being developed. For example, analysis of the impact of the 111(d) rule on the reliability of the bulk power system (BPS) conducted by the North American Electric Reliability Corporation did not become available in time for consideration in this report. Even though EPA completed the 111(d) rule itself in October, 2015, EPA continues to work on other regulatory developments that should also be taken into account in state plan development. The same day EPA finalized the 111(d) rule, it proposed a set of rules that will establish the federal plan it will impose on states that

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[1] Alaska and Hawaii are not subject to the 111(d) rule. Vermont and the District of Columbia have no electric generating units that are subject to it.

[2] West Virginia coal is exported to over twenty other states. Among these states, Pennsylvania, Ohio and North Carolina are the three largest consumers of West Virginia production.

refuse or fail to submit a state 111(d) plan. The EPA also proposed model state trading rules for the Emission Rate Credit (ERC) and allowance trading programs that are contemplated by the final 111(d) rule. It is not expected to finalize these rules until late summer. Further, the EPA continues to work on the details of the Clean Energy Incentive Program (CEIP) and Evaluation, Measurement and Verification (EM&V) requirements that are both included in the final 111(d) rule. In addition to EPA's ongoing piecemeal establishment of the overall section 111(d) program, the operator of the grid and wholesale power markets for the region of the country that includes West Virginia, PJM Interconnection (PJM), will not complete its economic analysis of the 111(d) rule until June, 2016. PJM's analysis of the impact of the 111(d) rule on the reliability of the grid is not likely to be completed until July, 2016. These analyses merit consideration in state plan development. Further, other entities continue to refine modeling of the 111(d) rule's impacts. Decisions other states make on pathways toward a state plan impact the economics of decisions West Virginia will have to make. This report represents the best attempt by the WVDEP to provide the analysis the Legislature required within the constraints of the deadline imposed.

II. Executive Summary

Several developments put the United States on a course toward regulation of greenhouse gas emissions from power plants. First, in 1992, the Senate ratified the United Nations Framework Convention on Climate Change, committing the country to make greenhouse gas reductions. Second, the United States Supreme Court has determined that greenhouse gases are "air pollutants" subject to some form of regulation under the Clean Air Act. Third, EPA has made an endangerment finding with respect to greenhouse gas emissions that requires it to act. Unless one or more of these developments is reversed or negated, greenhouse gas emissions are likely to be regulated in a variety of ways. Power plants are the largest category of greenhouse gas emissions in the United States. Therefore, they occupy a high profile among potential targets for regulation.

On October 23, 2015, the EPA published its final section 111(b) rule for CO_2 emissions from new power plants in the Federal Register. Establishment of this rule is a prerequisite for regulation of existing power plants under section 111(d). The performance standards for new plants in the 111(b) rule are based on application of partial carbon capture and storage (CCS). This rule has been characterized as a ban on new coal-fired power. If no new coal-fired power is built, the share of the nation's power production supplied by coal will necessarily decline over the coming decades as existing coal-fired plants either reach the end of their remaining useful lives or are forced from the market by a combination of environmental regulation and market forces.

On October 23, 2015, the EPA also published its final 111(d) rule in the Federal Register. This rule regulates CO_2 emissions from existing fossil-fuel fired power plants. For West Virginia, the necessary CO_2 reductions equate to about 29% in a mass-based compliance approach and 37% in a rate-based compliance approach from the emissions in the baseline year of 2012. In the baseline year, there were sixteen coal-fired power plants operating in West Virginia. Six of these plants have subsequently retired. All of the ten remaining coal-fired units in the state are "affected units" that are subject to regulation under this rule. None of the other existing power generation units in the state are subject to the rule.

The rule requires states to submit either a state plan to comply or obtain a two year extension by September 6, 2016. The two year extension may be obtained by making an "initial submittal" to EPA. The rule contemplates that EPA will develop a federal plan for a state if the state does not make one of these two filings on time, or if the state submits a plan which the EPA disapproves.

Both the 111(b) and 111(d) rules are being challenged in court. On February 9, 2016, the United States Supreme Court granted a stay of the 111(d) rule which has suspended the EPA's deadlines for an indefinite time while court cases challenging the rule proceed. If these lawsuits result in the 111(d) rule being vacated by the courts, there will be no deadline. Should the rule be upheld, the past approach of the courts in cases in which the EPA rules have been stayed and later upheld has been to require the agency to extend the regulatory deadlines contained in the rules to allow an amount of time for action following the conclusion of litigation that is comparable to what would have been allowed in the absence of litigation and a stay.

Under the 111(d) rule, a state can choose whether to adopt the rate-based or mass-based approach to compliance. In either case, the rule contemplates trading of a type of "compliance currency" as a means for coal-fired generators to comply. In the rate-based approach, the units of this currency are called emission rate credits (ERCs). They are generated by zero and low CO_2 emitting power or energy efficiency projects that reduce coal's share of the nation's energy mix. In the mass-based compliance approach, the units of this currency are called allowances. Generally, allowances result from the shutdown or reduced operation of other coal or higher CO_2 emitting power sources. The 111(d) rule allows trading of these compliance currencies within a single state, in a multistate or regional area or nationally. It does not allow trading between rate-based states and mass-based states.

Among the many decisions that a state must make as part of developing a state plan, there are two decisions a state will make that have the greatest effect on the analysis of the 111(d) rule's impact: (1) whether to choose a rate-based or mass-based compliance approach, and (2) the extent of trading in ERCs or allowances it allows – instate-only, multi-state or national trading.

HB2004 requires the WVDEP to assess the feasibility of the state's compliance with the EPA rule, based on a comprehensive analysis. To conduct the analysis the Legislature required, the WVDEP: (1) solicited information from the owners of the state's electric generating units (EGUs); (2) hired Marshall University's Center for Business and Economic Research (CBER) which subcontracted with Energy Ventures Analysis, Inc. (EVA) of Arlington, Virginia for economic and market analysis of the impact of the 111(d) rule on the state; (3) identified stakeholders from business, labor, environmental and public interest groups and governmental agencies that may have useful information concerning this assessment and solicited their input; (4) notified the public of the feasibility assessment and comprehensive analysis and solicited comment from the public; and, (5) conducted independent research on topics related to the assessment and analysis.

EVA conducted modeling of West Virginia generated power in future power markets in a business as usual scenario (BAU - no EPA rule; this is shown on the figure below in navy), plus the four primary potential state compliance pathways under the EPA rule:

1. a rate-based state plan, with national trading of ERCs (purple line on the figure below);

2. a rate-based state plan, with instate-only trading of ERCs (green line on the figure below);

3. a mass-based state plan, with national trading of allowances (red line on the figure below): and,

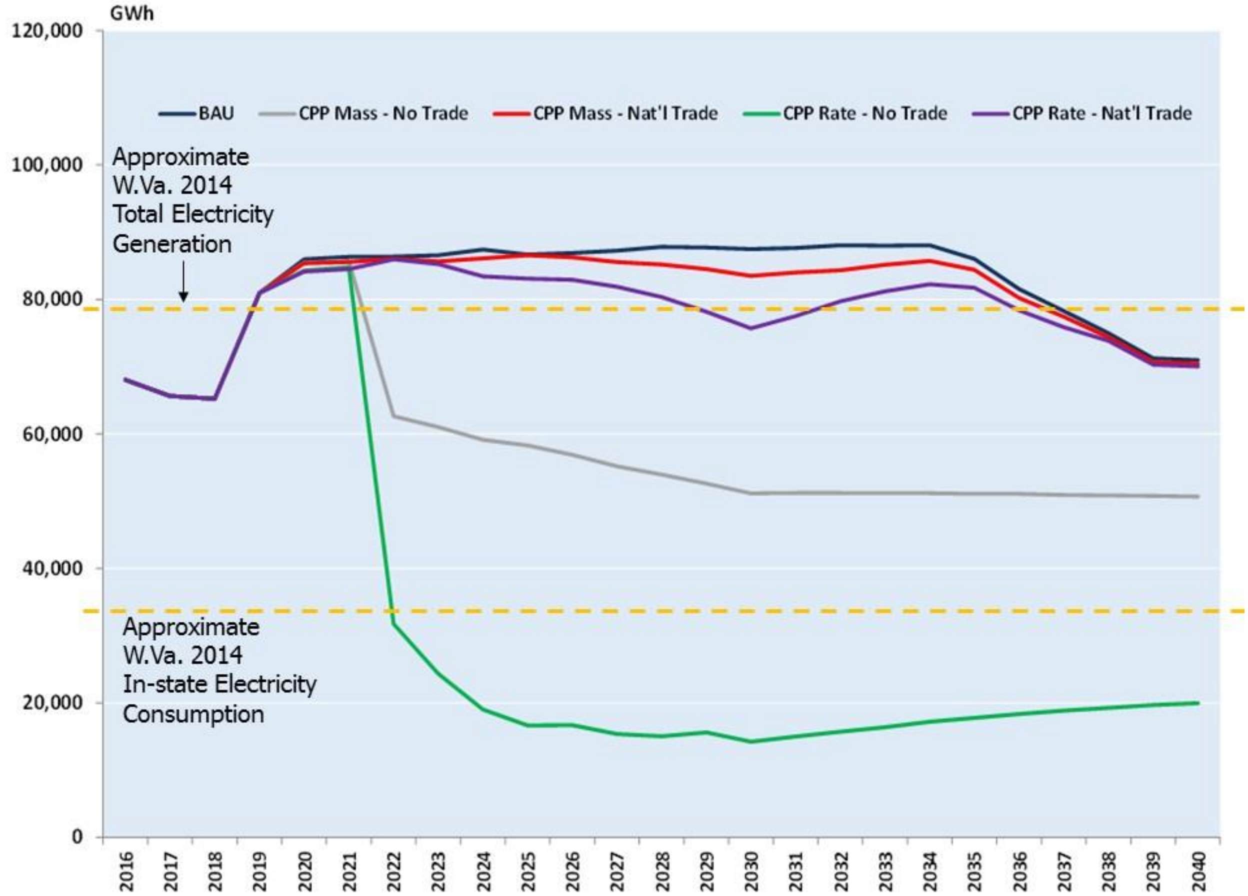
4. a mass-based state plan, with instate-only trading of allowances (gray line on the figure below).

These do not represent all possible state plan scenarios, but do provide the outer bounds of impacts from possible state plan decisions. CBER conducted modeling of regional economic impacts arising from each of these scenarios, plus the impacts of potential power plant closures. CBER's report is included in the appendix[3].

In 2014, power plants in the state produced 79.2 million megawatt hours (MWh) of power, 32.7 million of which were consumed in West Virginia. These values provide a useful comparison to the potential impact of the four state plan approaches modeled by CBER and EVA. The figure below depicts EVA's modeling of the market for power generated by West Virginias's coal units leading up to implementation of the 111(d) rule in 2022, through the 2022 implementation period and thereafter under the four state compliance scenarios, in comparison to business as usual and 2014 West Virginia power generation and consumption.

[3] Shand, J., Risch, C., et al. "EPA's Carbon Dioxide Rule for Existing Power Plants: Economic Impact Analysis of Potential State Plan Alternatives for West Virginia," March 2016 (CBER Report), p. 31.

Figure 1: West Virginia Coal-Fired Power Generation Projections (GWh), BAU compared to Compliance Scenarios



Source: EVA Analysis
[Reproduced from CBER Report, Figure 5 – modified by WVDEP, to show West Virginia 2014 Electricity Generation and Consumption. CBER calls the instate-only trading options "No Trade."]

As can be seen from this figure, the analysis performed by CBER and EVA projects that the state's electric generation will exceed or approach 2014 levels throughout the implementation of the 111(d) rule and beyond, under either a mass or a rate-based state plan with national trading. Accordingly, based on the CBER – EVA analysis, compliance with the 111(d) rule is feasible from an economic standpoint under either of these scenarios. Based solely on this analysis, the best choice for the state would be to adopt a mass-based state plan with national trading of allowances. However, further analysis is warranted before a choice between these two approaches should be made. As is also shown by this figure, the analysis shows that mass and rate-based plans with trading only within the state can be expected to have dramatically negative impacts on the ability of West Virginia-generated power to compete in energy markets.

There are two key factors that influence the CBER – EVA projections. The first is partly a function of energy market projections and partly a function of the impact of the 111(d) rule on these markets. Power produced from natural gas has displaced some of the coal-fired share of power generation in recent years due, in part, to the low prices for natural gas that have resulted from overcapacity to produce arising from the recent shale gas boom. EVA predicts rising demand for gas because of an export market that it expects to develop over the next few years and because of increased demand for gas from electric generating units, at least in part in response to the 111(d) rule. With increased gas prices from increased demand, coal-fired electric generation becomes more competitive in energy markets.

The second key factor is the development of robust trading markets for allowances or ERCs a unit must hold in order to comply. The projections are based on trading in national markets in which all states are engaged in trading in a single market. Because of the differing circumstances confronting states that are choosing between the mass-based approach and the rate-based approach, a national market in which all states have chosen only one of these two approaches is very unlikely. However, a market that is sufficiently robust to provide low cost compliance does not require all states to adopt the same approach. Under some preliminary simulations WVDEP has seen, West Virginia may actually fare better in some regional combinations of states than in a national market. If West Virginia were to find itself in a situation in which its electric generating units have few trading options, the economics of compliance with the EPA rule change dramatically. That is not expected to be the case with a mass-based plan. Although the WVDEP is not engaged in preparation of a state plan, it intends to continue its communication with other states concerning their state plan developments while the litigation over the 111(d) rule is pending in order to be in the best position to protect the state's interests should development of a state plan be required.

Although there are at least two scenarios in which compliance with the EPA's 111(d) rule is feasible from an economic standpoint, compliance with this rule is not feasible from a legal standpoint. Presently state law prohibits the state plan option projected to have the least impact. This problem can be fixed if the changes in West Virginia law recommended below (page 11) are made. Most of these changes would also be necessary if the state were to adopt the second least impactful state plan option, a rate-based plan with national trading. If these changes are made, the Legislature should also clarify that WVDEP is authorized to seek a two year extension of EPA's deadline, should development of a state plan become necessary.

EPA's mandate for a 29% reduction in the number of tons of CO_2 emitted from existing coal plants in the state is equal to a reduction of 21 million tons from 2012 levels. West Virginia's CO_2 emissions have already been reduced by the closure of six coal plants that emitted 4.4 million tons of CO_2 in 2012. These closures may provide a jumpstart toward meeting EPA's mass limit for the state. The 4.4 million tons of CO_2 these plants produced in 2012 is 6% of the 2012 total. Assuming other coal plants in the state have not increased their output since then, the state would need additional reductions of 23% or 16.6 million tons from 2012 levels to reach EPA's final mass limit.

Other developments that impact state plan decision making are ongoing. EPA is working on related rule proposals, including one which will establish a federal plan for states that fail to develop a state plan, plus model trading rules for both the rate and mass-based compliance approaches. The content of these rules, when finalized will inform state plan decisions. The North American Electric Reliability Corporation (NERC) is finalizing its assessment of the

111(d) rule's impact on reliability of the grid. PJM, the operator of the grid for West Virginia's region of the country is expected to finalize an economic analysis of the 111(d) rule in June and a reliability analysis of it in July. These and other analyses of the final 111(d) rule should be considered in state plan development. The compliance approaches other states take may have a significant impact on the economics of the path West Virginia chooses.

Should the 111(d) rule be upheld, West Virginia may have difficulty developing a timely state plan submission due to all of the legislative approvals required. Over three successive legislative sessions, WVDEP would have to obtain legislative approval of the changes in state statutes that are necessary to develop a state plan, approval of legislative rules that will comprise the enforceable portion of the state plan, and approval of the state plan itself. Very little time will be available to engage stakeholders and the public in order to develop a consensus around a state plan approach before a plan must be proposed.

Under the state plan scenarios modeled by CBER and EVA, the rate-based and mass-based scenarios with instate-only trading may result in power plant shutdowns. Because internal circumstances within the ownership of each generating unit that may not be publicly known is likely to affect corporate decisions on plant closures, CBER did not undertake to predict which plants might close in these scenarios. However, to address the economic impact of potential plant closures, CBER performed an analysis of the impact from a hypothetical closure of each of these units. The narrative CBER's Report provides concerning hypothetical plant closures is repeated below, starting at page 70. More detail on these potential impacts is provided in the full CBER report, which is attached in the appendix. Some notable figures from CBER's report are summarized below (all from hypothetical plant closures, this is not a projection of actual plant closures):

- Potential job losses (including indirect and induced job losses) in the electricity sector range from a low of 118 jobs impacted by closure of the Morgantown Energy Associates facility to a high of 863 jobs impacted by closure of the John Amos facility.

- Potential job losses in the West Virginia coal sector range from a low of 89 jobs impacted by a closure of the Mt. Storm facility to a high of 575 jobs impacted by a closure of the Harrison facility.[4]

- Potential lost West Virginia coal sales range from a low of $43 Million annually from a closure of the Mt. Storm facility to a high of $282 Million annually from a closure of the Harrison facility.

- Potential lost severance tax receipts range from a low of $2.2 Million annually from closure of the Mt. Storm facility to a high of $14 Million annually from a closure of the Harrison facility.

[4] Plants that use little to no West Virginia coal are not considered at the low range of lost coal jobs, coal sales or severance tax. These plants include Grant Town, Morgantown Energy Associates and Pleasants power stations.

- Potential lost state income tax receipts range from a low of $311,000 from a closure of the Morgantown Energy Associates facility to a high of $2.2 Million annually from a closure of the John Amos facility.

The rest of this report is organized as follows: In section III, WVDEP presents its findings on the two feasibility determinations the Legislature required it to make and responds to the Legislature's request for recommended changes to state law that are necessary to facilitate state plan development. Section IV contains the Comprehensive Analysis the Legislature required the WVDEP to perform. The first part of the Comprehensive Analysis contains background information that may provide useful perspective to policy makers who make decisions on a state plan under the 111(d) rule, including a brief summary of the history of greenhouse gas regulation leading to the adoption of EPA's CO_2 rules for power plants, an overview of EPA's CO_2 rules for power plants, a summary of the system for delivery of electricity nationally and at the state level and a description of the regional power markets in which West Virginia power producers compete. The second part of the Comprehensive Analysis examines each of the eleven factors the Legislature directed WVDEP to consider in this report. Each of the four state plan approaches modeled by CBER and EVA are discussed throughout this examination of the eleven factors. The third part concludes the Comprehensive Analysis with an examination of policy decisions that must be made if a state plan is adopted and provides a timeline for developing a state plan.

III. WVDEP's Findings

a. Feasibility Determinations

First Feasibility Determination: Is the creation of a state plan feasible based on the comprehensive analysis? If no, why?

WVDEP Answer: No. West Virginia law prohibits the type of compliance mechanisms that are necessary to comply with EPA's limits for the state. If the state choses to develop a state plan based on the approach that CBER – EVA's modeling projects will have the least disruption to the state and its people, changes in state law may be needed.

W.Va. Code §§ 22-5-20(e) and (f) limit the compliance approaches WVDEP may utilize in a state plan. Under these sections, the standards of performance that are the basis of a state plan are limited to "measures that can be undertaken at each coal-fired electric generating unit to reduce carbon dioxide emissions from the unit . . . ". In addition, these sections prohibit WVDEP's standards of performance from utilizing fuel switching or limitation of the economic utilization of a generating unit.[5]

Under the limitations of W.Va. Code §§ 22-5-20(e) and (f) and present technology, an improvement in a plant's efficiency in converting heat into electric power is the only type of carbon dioxide emissions reduction measure that is feasible to be taken "at each unit" without

[5] W.Va. Code §§ 22-5-20(e) and (f) only speak to what WVDEP may or may not do in establishing the standards of performance in a state plan. They do not prohibit owners of coal-fired power plants from making business decisions to switch fuels, co-fire, reduce operation of a unit or shut a unit down as part of a compliance strategy.

switching fuels or limiting utilization of the unit.[6] EPA's optimistic estimate of what might be available through such efficiency gains is limited to a 4.3% improvement. The owners of West Virginia's coal-fired power plants, which are already among the most efficient in the country, estimate that improvements of only 1 to 2% are reasonably available.

Against these relatively meager emissions reductions that might be available through "at each unit" measures, consider that for West Virginia, the final reductions EPA has mandated require a 37% reduction in the hourly rate of carbon dioxide emissions (measured in net pounds per megawatt-hour – lb CO_2/MWh net) or, alternatively, a 29% reduction in the mass of carbon dioxide emissions (measured in tons per year). The heat efficiency improvements that are available under the "at each unit" limitation of state law will not get West Virginia power plants anywhere close to EPA's limits for the state. This limitation, alone, will not allow development of a state plan that can comply with EPA's rule. Changes to this and other provisions of state law will make it feasible to develop a state plan that causes the least possible disruption from the status quo. The WVDEP discusses these changes below in the section on "Changes in State Law Necessary for Development of a State Plan" at page 11.

In addressing the first feasibility determination and in the discussion of necessary changes in state law, the WVDEP is interpreting the "at each coal-fired electric generating unit" limitation of W.Va. Code §§ 22-5-20(e)(2) and (3) to only allow modifications to either the generating unit itself or the processes employed in the physical operation of that unit as a means of compliance, so-called "inside the fence" measures, and to prohibit the trading of ERCs or allowances, which are necessarily derived from emissions reductions efforts made elsewhere, as a compliance mechanism. If inclusion of the ERCs or allowances a unit has purchased in order to comply as an asset on that unit's financial statements is interpreted to be an "at each unit" compliance measure, the WVDEP's response to the first feasibility determination and its recommendation of changes to state law would be different. However, the WVDEP does not believe that the lodging of an intangible asset on a unit's books is what the Legislature intended with the "measures that can be undertaken at each unit" limitation of W.Va. Code §§ 22-5-20(e)(2) and (3).

Second Feasibility Determination: Is creation of a state plan feasible before the deadline to submit a state plan to EPA under the Section 111(d) Rule, assuming no extensions of time are granted by the EPA?

WVDEP Answer: The stay of the 111(d) rule granted by the United States Supreme Court has suspended the EPA's deadlines for an indefinite time. Therefore, the WVDEP is unable to answer this question at this time.

In the final rule, EPA established an initial deadline of September 6, 2016 for submission of a state plan. However, on February 9, 2016, the United States Supreme Court granted a stay of the rule. As a result, all deadlines in the EPA rule are delayed during the pendency of the lawsuits challenging the rule. If these lawsuits result in the 111(d) rule being vacated by the courts, there will be no deadline. Should the rule be upheld, the WVDEP expects that EPA be required to extend the regulatory deadlines contained in the rules to allow an amount of time for action following the conclusion of litigation that is comparable to what would have been allowed

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6 W.Va. Code §§ 22-5-20(e)(2) and (3). A more complete discussion of each of the potential "at the unit" measures can be found below in the discussion of Comprehensive Analysis Factors 5, 6 and 7 starting at page 61.

in the absence of litigation and a stay.[7] Although the WVDEP shares the belief of those challenging the rule that it is unlawful, the WVDEP cannot predict with certainty either the outcome of the litigation or when that outcome will be final. Accordingly, the WVDEP cannot predict when an EPA deadline will fall or whether there will even be an EPA deadline under this rule.

b. Recommended Changes in State Law for Development of a State Plan

Part of the comprehensive analysis HB2004 requires is an assessment of the "need for legislative or other changes in state law." W.Va. Code § 22-5-20(c)(1).[8] Changes in state law may be necessary if the state is to submit an approvable state plan based on the approach that CBER – EVA's modeling suggests has the least impact on the states citizens and industry.

W.Va. Code §§ 22-5-20(d), (e), and (f) specify some of the structure and content that must be part of a state plan. Parts of these provisions would prohibit development of a state plan that would have the least impact on the state. Other parts may have had application under EPA's proposed 111(d) rule, but cease to have any real application as a result of changes EPA made in its final 111(d) rule. Making the changes recommended below will also allow the WVDEP greater flexibility in attempting to craft a plan that is in the best interests of the state. Any concerns the Legislature may have about making these changes should be ameliorated by the fact that, effectively, the Legislature must approve a state plan not once, but twice. W.Va. Code § 29A-3-12 makes the state rules that comprise the legally binding elements of a state plan subject to legislative approval. In addition, in W.Va. Code § 22-5-20(b), the Legislature retained the ultimate authority to approve the entirety of any section 111(d) plan offered by the WVDEP, [9] before it can be submitted to EPA. The WVDEP is not recommending that this provision be changed. The state plan approval authority the Legislature retained in W.Va. Code § 22-5-20(b) gives the Legislature the ultimate control over the content of a state plan.

1. Consider Removing W.Va. Code §§ 22-5-20(e)(2) and (3) to Allow a Mass-Based Plan, With Trading as a Means of Compliance

As part of its efforts to analyze the feasibility questions and provide the comprehensive analysis the Legislature required, the WVDEP contracted with CBER and EVA to provide market and economic analysis and projections concerning future electric generation in West Virginia, both under a business-as-usual approach, which assumes the EPA rule had never been promulgated, and under four different broad compliance alternatives under the 111(d) rule.[10] The BAU projections show what is expected in the absence of a 111(d) rule. They serve as a useful baseline against which CBER – EVA's projections based on the 111(d) rule compliance alternatives can be compared in assessing a state plan's impact. It should be noted, however, that

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[7] *NRDC v. EPA*, 22 F.3d 1125 (D.C. Cir. 1994); Order, No. 98-1497, *Michigan v. EPA*, ECF 524995 (D.C. Cir. June 22, 2000).

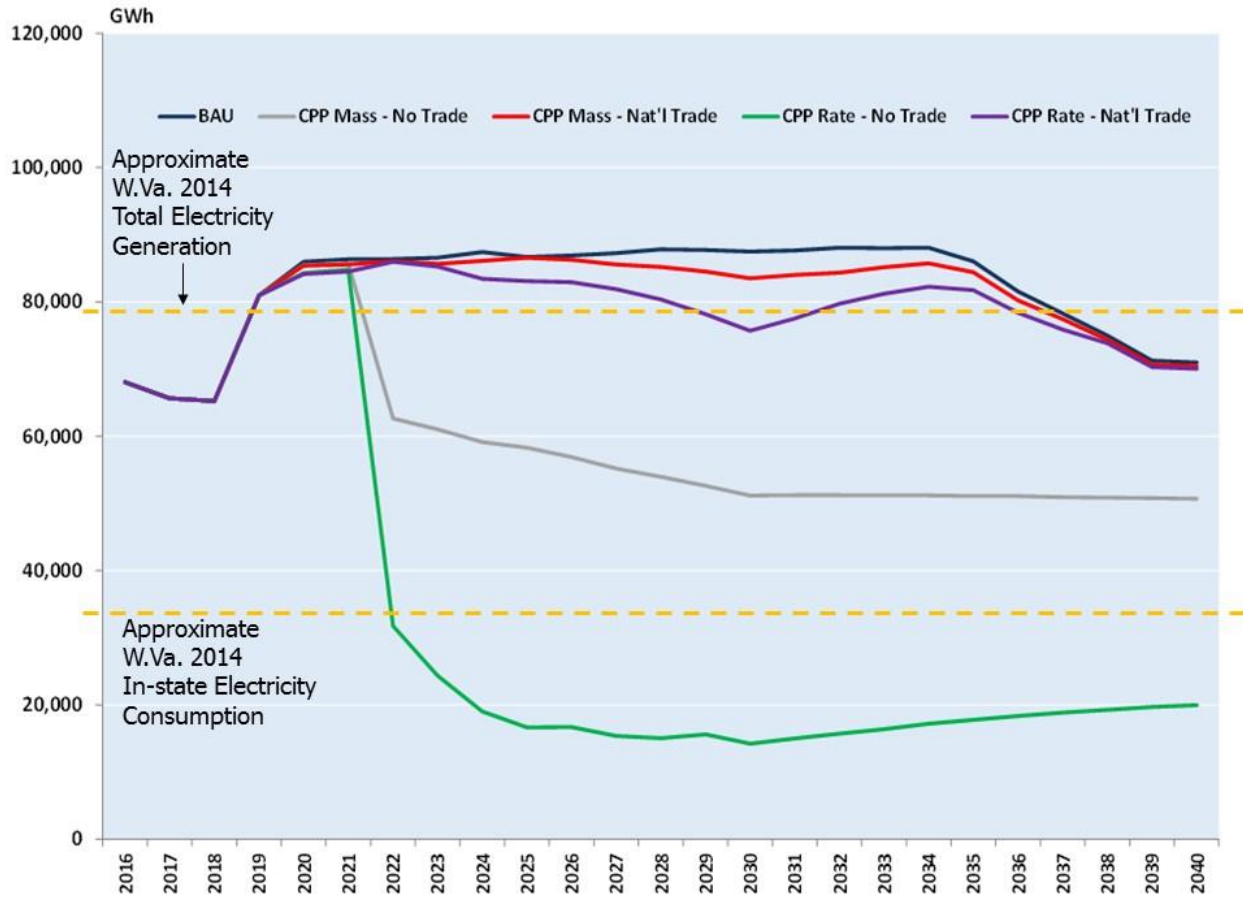
[8] In the 2016 legislative session, Senate Bill 691 made changes to the language of W.Va. Code § 22-5-20(c)(1) that do not impact its requirements for a comprehensive analysis or the changes in state law that are recommended in this report.

[9] In addition to a legally binding set of rules, a state plan must also include information and make certain demonstrations. *See*, 40 C.F.R, §§ 60.5740 and 60.5745.

[10] CBER's Report to WVDEP is included as an appendix to this report. Its findings are discussed below in Comprehensive Analysis Factors 1, 4, 9 and various other places.

if the 111(d) rule is upheld by the courts, the more relevant comparison will be between the relative impacts projected for an EPA federal plan and the four major state plan alternatives.[11] The four alternatives are plans for compliance with EPA's: (1) mass-based limit with national trading of allowances, (2) mass-based limit with instate-only trading of allowances, (3) rate-based limit with national trading of ERCs, and (4) rate-based limit with instate-only trading of ERCs.

Figure 2: West Virginia Coal-Fired Power Generation Projections (GWh), BAU compared to Compliance Scenarios



Source: EVA Analysis
[Reproduced from CBER Report, Figure 5 – modified by WVDEP, to show West Virginia 2014 Electricity Generation and Consumption. CBER calls the instate-only trading options "No Trade."]

As can be seen from this chart, among the four compliance scenarios, CBER – EVA's modeling of the mass-based approach with national trading most closely approximated the BAU

[11] The impacts of EPA's federal plan could not be modeled because it exists only as a proposal at this time. EPA has stated that it will not finalize a federal plan until a state fails or refuses to adopt a state plan. As a result of the Supreme Court's stay of the 111(d) rule and its deadlines for submission of a state plan, it is uncertain when, if ever, a federal plan will be finalized.

projections, followed by the rate-based plan with national trading. Notably, their projections for BAU and both scenarios with national trading approach or exceed the total electric production from the state in 2014 – 79,200 GWh[12] – for the entire period of 111(d) rule implementation and beyond, at least from 2019 through 2035. In contrast, CBER – EVA predict a mass-based plan with no trading would cause severe disruptions. The impact of a rate-based plan with no trading would be even worse. The CBER - EVA projection that a mass-based plan under the 111(d) rule is the least impactful one for West Virginia is generally consistent with 111(d) modeling results the WVDEP has seen from others.

The approach CBER – EVA modeling shows is least impactful, a mass-based plan with national trading, is prohibited in several ways by W.Va. Code § 22-5-20(e). To meet EPA's final limit in a mass-based plan, West Virginia electric generating units must reduce their aggregate CO_2 emissions from approximately 72 million tons in the base year of 2012 to approximately 51 million tons in 2030. This is effectively a limit on plant output. In the absence of allowance trading, meeting this limit will require West Virginia's units to operate much less than has been economically viable for them in the past. By its very nature, a mass-type limit on output by West Virginia power plants is a limit on the economic utilization of a unit that violates W.Va. Code § 22-5-20(e)(3)'s prohibition against such limits.

To operate at any level close to its pre-111(d) rule capacity under a mass-based compliance plan, the CBER – EVA modeling shows that a coal-fired unit will have to purchase allowances that are traded in a national or regional market. The allowances available in the market represent either: (1) tons of CO_2 not emitted because other coal- or gas-fired units in West Virginia or elsewhere have shutdown or reduced operations; (2) tons of CO_2 emissions avoided as a result of substituting renewable or low carbon energy for energy derived from coal or gas; or (3) tons of CO_2 emissions avoided as a result of reduced demand for coal- or gas-generated energy through the implementation of energy efficiency measures for low income residents or minorities. W.Va. Code §§ 22-5-20(e)(2) and (3) both limit the type of CO_2 reduction measures to unit-specific – reductions must come from "measures undertaken at each coal-fired electric generating unit". Whatever the source of a unit's purchased allowances may be, in no case can they possibly be derived from measures taken at that unit. The trading mechanism that is necessary to comply violates W.Va. Code §§ 22-5-20(e)(2)'s and (3)'s "at the unit" limitation on compliance measures. In the event the state chooses the second least impactful compliance route according to the CBER – EVA analysis, a rate-based plan with national trading, W.Va. Code §§ 22-5-20(e)(2) and (3) would similarly prohibit the trading of ERCs that would be necessary for coal units to comply in a rate-based plan, because the ERCs do not represent measures "taken at the unit".

In conclusion, CBER – EVA's economic and market projections suggest West Virginia's coal-fired units might be able to reach a level near that of the unregulated, BAU projections if trading allowances or ERCs in a robust market is a compliance option that is available to them. W.Va. Code §§ 22-5-20(e)(2) and (3) prohibit trading. If West Virginia is required to develop a state plan, the Legislature may wish to consider removing these provisions from state law. In this event, the Legislature may wish to consider adding language that specifically authorizes the

[12] Shand, J., Risch, C., et al. "EPA's Carbon Dioxide Rule for Existing Power Plants: Economic Impact Analysis of Potential State Plan Alternatives for West Virginia," March 2016 (CBER Report), p. 20; EIA-923.

WVDEP to include the trading of emissions allowances or credits as a means of complying with CO_2 standards developed pursuant to section 111 of the Clean Air Act.[13]

2. W.Va. Code § 22-5-20(e)(1) Applies to a Function the Clean Air Act Assigns to EPA, Not the State

The provisions of W.Va. Code § 22-5-20(e)(1), which govern the development of a "best system of emissions reduction" (BSER), more or less follow the Clean Air Act concerning BSER. Section 111(a)(1) of the Clean Air Act makes the EPA, not the state, responsible for determining a BSER. Therefore, the Legislature may wish to consider removal of W.Va. Code § 22-5-20(e)(1).

3. EPA's Final Rule Does Not Apply to the State's Existing Gas-Fired Units; There is No Need to Treat Them Separately

The constraints on the WVDEP's development of standards of performance for coal-fired units imposed in W.Va. Code § 22-5-20(e) are mirrored as to gas-fired units in W.Va. Code § 22-5-20(f). The only existing gas-fired units in West Virginia are excluded from the EPA rule by EPA's own description of the units to which it applies.[14] Unless West Virginia elects to include new gas-fired units in a state plan, a state plan option discussed below (starting at page 86) that may not be in the state's best interest, W.Va. Code § 22-5-20(f) has no application. Similarly, the first sentence in W.Va. Code § 22-5-20(d), which requires WVDEP to develop separate standards for coal- and for gas-fired units, has no application. The Legislature may wish to consider removal of W.Va. Code § 22-5-20(f) and the first sentence of W.Va. Code §22-5-20(d).

IV. Comprehensive Analysis

a. Helpful Perspectives and Context for Policy Decision Makers

W.Va. Code § 22-5-20(c)(1), requires the WVDEP's comprehensive analysis to address: "the effect of the Section 111(d) rule on the state, *including, but not limited to*, the need for legislative or other changes to state law, and the factors referenced in subsection (g)." *Id.* (Emphasis supplied). To maximize the utility of this report and better assist the Legislature as decision makers on policy issues, the comprehensive analysis includes background information on several topics in order to provide some context to the EPA rule and decisions that must be made in the development of a state plan, in addition to an analysis of the eleven factors identified in W.Va. Code § 22-5-20(g). These include a brief summary of efforts to regulate greenhouse gases, an overview of the EPA rule, a profile of the state's power generation fleet, and an overview of how West Virginia's units function in the grid and regional electricity markets. Following an analysis of the eleven factors identified by the Legislature in W.Va. Code § 22-5-20(g), the report of the comprehensive analysis concludes with a discussion of the different

[13] W.Va. Code § 22-5-18 already authorizes trading in programs to comply with "criteria" air pollutants that are regulated under section 110 of the Clean Air Act. Similar authority should be granted as to regulation of CO_2 emissions under section 111.

[14] 40 C.F.R. § 60.5845; *see*, definitions in 40 C.F.R. § 60.5880.

policy decisions that must be made in the development of a state plan. Because the discussion of the need for changes to state law is closely related to the first of the two feasibility determinations W.Va. Code § 22-5-20(c)(1) requires the WVDEP to make, this discussion is included above in the summary of WVDEP's Findings, starting at page 9, rather than in the comprehensive analysis below.

1. Brief Overview of Efforts to Regulate Carbon Emissions

The 111(d) rule is just one piece of a larger effort to regulate emissions of CO_2 and the other gases that have been deemed greenhouse gases. Decision makers on the policy issues involved in developing a state plan may be better equipped if they know how this rule fits into the larger regulatory landscape of which it is part. The overview WVDEP provides here is not an exhaustive history of the efforts to regulate the emissions but does provide a summary of the most prominent events in the recent history of such efforts globally and in the United States.

A. International Efforts to Regulate Greenhouse Gases

Carbon dioxide and other greenhouse gases are reasonably consistent in their concentrations in the atmosphere throughout the world. Thus, if attempts to control their concentrations are to succeed, a global effort would be necessary. Toward this end, the United States and 196 other countries are participants in the 1992 United Nations Framework Convention on Climate Change (UNFCCC).[15] The U.S. ratified the Convention on October 15, 1992.[16] Among other things, parties to the UNFCCC committed to develop and publish national inventories of greenhouse gases and formulate implement and publish national programs for mitigation of and adaptation to climate change. Since 1995, an annual Conference of the Parties (COP) has been held pursuant to the UNFCCC at which parties report on progress in implementing the agreement. The UNFCCC established a non-binding goal for developed countries to reduce emissions of greenhouse gases to 1990 levels by 2050.[17] Another more general goal was to prevent dangerous anthropogenic interference with the climate system.[18]

In 1997, the COP produced the Kyoto Protocol which established legally binding quantitative emissions limits for developed countries[19] (Annex I countries in UNFCCC parlance) but did not establish any similar limits for developing countries. Notably, some of the largest economies in today's world, China, Brazil, Mexico, South Korea and India, were not included as developed, or Annex I, countries in the UNFCCC.[20] The approach for developed countries versus that for developing countries has been prominent among the dynamics in past international climate discussions. The United States has been unwilling to give up the economic advantage of inexpensive, greenhouse gas-intense energy if others against which it competes in the global marketplace are allowed to have it. On the other hand, the developing countries have viewed increasing levels of greenhouse gases in the atmosphere as a problem that has principally

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15 http://unfccc.int/parties_and_observers/parties/items/2352.php Last visited April 15, 2016.
16 http://unfccc.int/tools_xml/country_US.html Last visited April 15, 2016.
17 United Nations Framework Convention on Climate Change, Article 4, Paragraph 2(b).
18 United Nations Framework Convention on Climate Change, Article 2.
19 Kyoto Protocol, Article 3.
20 http://unfccc.int/parties_and_observers/parties/non_annex_i/items/2833.php Last visited April 15, 2016.

been the making of the United States and other wealthy nations. Developing countries have not been willing to give up access to inexpensive energy that may be a vehicle to greater prosperity for them.

The United States has not ratified or participated in the Kyoto Protocol.[21] In fact, the United States Senate adopted a resolution sponsored by West Virginia Senator Robert C. Byrd and a bi-partisan group of over sixty other Senators expressing the "sense of the Senate" in opposition to the Kyoto Protocol or any other agreement that places greenhouse gas emissions limits on developed countries without imposing specific limits for developing countries. This resolution was approved by a vote of 95 – 0. The resolution recited as one of its bases:

> [T]he Senate strongly believes that the [Kyoto Protocol], because of the disparity of treatment between Annex I Parties and Developing Countries and the level of required emission reductions, could result in serious harm to the United States economy, including significant job loss, trade disadvantages, increased energy and consumer costs, or any combination thereof . . .[22]

The 21st COP was conducted in Paris in December, 2015. It resulted in the recently announced Paris climate agreement.[23] The agreement aims to keep temperature rise above pre-industrial levels to 2 ºC or less.[24] Conservative estimates of the emissions reductions the United States will have to make to do this suggest that an 80% reduction in emissions from 1990 levels is required to meet these goals.[25] The agreement also states that parties will pursue efforts to limit the rise to 1.5 ºC or less.[26] The parties to the Paris Agreement have invited the United Nations' Intergovernmental Panel on Climate Change (IPCC) to produce a special report in 2018 that details the effects of a 1.5 ºC rise in temperature as well as the measures that are necessary to hold temperature increases to this level.

The Paris Agreement does not link its 1.5 and 2 ºC goals to a mandate of actual emissions reductions that are necessary to achieve these goals. Instead, the agreement takes a "bottom-up" approach in which the actual reduction efforts each country commits to undertake are defined by the Individual Nationally Determined Contribution (INDC) each country offers. The INDC for the United States is a 26 – 28% reduction in greenhouse gas emissions from 2005 levels by 2025.[27] By comparison, China, the largest emitter of greenhouse gases in the world, has offered an INDC that only requires the *increase* in its greenhouse gas emissions to peak by 2030, with its best efforts to peak earlier. China also agreed to obtain 20% of its energy from low emissions

21 http://unfccc.int/tools_xml/country_US.html Last visited April 15, 2016.

22 S.Res. 98, 105th Congress (1997).

23 http://unfccc.int/paris_agreement/items/9485.php Last visited April 15, 2016.

24 Paris Agreement, Article 2, Paragraph 1(a).

25 The Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (2007) projects that 80 – 95% reductions in greenhouse gas emissions from 1990 levels would be required by 2050 in order to stabilize atmospheric concentrations of CO_2-eq at 450 ppm. These projections have been further refined in the IPCC's 2014 Fifth Assessment Report.

26 Paris Agreement, Article 2, Paragraph 1(a).

27 http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf Last Visited April 16, 2016.

sources by 2030.[28] The aggregate of the INDCs is believed to be insufficient to achieve the 2 ºC goal. To bring the parties closer to measures believed to be necessary to achieve this goal, the agreement contemplates that INDCs will be updated and strengthened at least once every five (5) years, beginning in 2020.[29] Perhaps aiming to avoid a repeat of the experience with the Kyoto Protocol, the Paris agreement is not called a "treaty" and avoids the use of mandatory language. Reportedly, the administration has no intention of submitting the Paris Agreement to the Senate for ratification.

The Paris Agreement overcomes the past reluctance of developing countries to agree to greenhouse gas limits in two ways. First, with the bottom-up approach, each country writes its own rules - each country individually determines the emissions reduction measures it is willing to make in its INDC. Second, the Green Climate Fund, which was first developed conceptually in the COPs of 2009 and 2010, is continued. It offers developing countries financial assistance to help them mitigate and adapt to climate change.[30] The United States State Department has a goal of mobilizing $100 Billion per year from a variety of public and private sources by 2020 for climate assistance to developing countries.[31] The President made an initial United States commitment of $3 Billion to the Green Climate Fund, $500 Million of which was provided in March, 2016.[32]

B. Attempts by Congress to Regulate Greenhouse Gases

Domestically in the US, since the Senate unanimously disapproved the Kyoto Protocol, several legislative proposals that would have resulted in largely unilateral efforts by the United States to reduce greenhouse gas emissions have failed. Among them are the McCain-Lieberman Climate Stewardship Act in 2003 and again in 2005, the Global Warming Pollution Reduction Act introduced by Senators Sanders and Boxer in 2007, and the American Clean Energy and Security Act in 2009 (also known as the Waxman Markey Bill).

C. United States Supreme Court Decisions Regarding Greenhouse Gases

As with nearly every area of concern in the environmental arena, there have been efforts to effect change in the regulation of greenhouse gases through administrative and judicial litigation.[33] In 1999, several groups petitioned EPA for rulemaking to regulate new motor vehicles with respect to greenhouse gas emissions pursuant to section 202(a) of the Clean Air

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28 http://www4.unfccc.int/submissions/INDC/Published%20Documents/China/1/China's%20INDC%20-%20on%2030%20June%202015.pdf Last visited April 15, 2016.

29 Paris Agreement, Article 4, Paragraph 9.

30 Paris Agreement, Article 9.

31 http://www.state.gov/e/oes/climate/faststart/index.htm Last Visited April 15, 2016.

32 http://thehill.com/policy/energy-environment/272177-obama-administration-makes-first-payment-to-un-climate-fund

33 This summary only discusses three cases dealing with this subject that have reached the United States Supreme Court. Some idea of the overall volume of such litigation can be gained by examining the chart of climate litigation in the United States maintained by the law firm of Arnold & Porter and the Sabine Center for Climate Change Law at the Columbia University Law School which now numbers nearly 900 pages. http://web.law.columbia.edu/climate-change/resources/us-climate-change-litigation-chart Last viewed April 1, 2016.

Act. Appeals from EPA's denial of this petition reached the United States Supreme Court in *Massachusetts v. EPA*.[34] Under the broad definition in the Clean Air Act,[35] the Supreme Court held that carbon dioxide and other greenhouse gases are "air pollutants" under the Act.[36] In *American Electric Power Co. v. Connecticut*,[37] the Court held that EPA has Clean Air Act authority to regulate greenhouse gas emissions from *new* coal-fired power plants under section 111 of the Clean Air Act, but also recognized that EPA would be barred from regulating *existing* coal-fired plants under subsection 111(d) if coal-fired power plants were regulated under section 112.[38] Lastly, in *UARG v. EPA*,[39] the Court recognized that the mere fact that greenhouse gases meet the statutory definition of the term "air pollutant" does not mean that EPA is compelled to apply every provision of the Clean Air Act dealing with "air pollutants" to greenhouse gases. In particular, the prevention of significant deterioration (PSD) and Title V permitting programs would be radically expanded to the point of being un-administrable if the "air pollutants" to which the tonnage thresholds for regulation under these programs include greenhouse gases. The Court held that EPA must, as it has done with other application of specific Clean Air Act provisions, give the term "air pollutants" a context-appropriate application to the PSD and Title V programs.

D. EPA's Endangerment Finding

The Supreme Court remanded the case in *Massachusetts v. EPA* to EPA for a determination of whether greenhouse gases, "may reasonably be anticipated to endanger public health or welfare" under section 202(a)(1) (an "endangerment finding"). Since EPA finalized its section 202(a)(1) endangerment finding on December 15, 2009, [40] it has initiated many efforts to promulgate rules for control of greenhouse gas emissions outside the electricity sector. It has also instituted "voluntary" initiatives to reduce greenhouse gas emissions from various industries. EPA's regulations directed at the electric power generation industry, which is the largest single source of greenhouse gas emissions in the US, will be discussed in the next section.

2. The EPA's Section 111 Rules for Power Plants

Section 111(b) of the Clean Air Act authorizes EPA to develop new source performance standards (NSPS) for different categories of sources of air pollutants. EPA may not regulate a

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34 549 U.S. 497 (2006).

35 "[A]ny physical, chemical . . . substance or matter which is emitted into or otherwise enters the ambient air . . . .". Section 302(g), Clean Air Act, 42 U.S.C. § 7602(g).

36 74 Fed.Reg. 66496. In this finding EPA concluded both that greenhouse gas emissions, in general, and from motor vehicles were a threat to public health and welfare. As a result, EPA finalized greenhouse gas emissions standards for light duty vehicle in 2010 and for heavy duty vehicles in 2011.

37 564 U.S. 410 (2011).

38 Significantly, while *American Electric Power Co. v. Connecticut* was pending in the Supreme Court, EPA proposed rules under Clean Air Act section 112 to regulate mercury emissions from coal fired power plants. EPA proceeded to finalize these rules subsequent to the *American Electric Power Co. v. Connecticut* decision. The issue of whether EPA's promulgation of rules that regulate coal fired power plants under section 112 is a bar to regulation of these power plants under section 111(d) is a prominent one in the cases challenging the 111(d) rule in court. Complicating the legal analysis is the fact that Congress adopted two inconsistent versions of section 111(d) in the 1990 amendments to the Clean Air Act.

39 573 U.S. ___, 137 S.Ct. 2427 (2014)

40 74 Fed.Reg. 66496 (December 15, 2009).

category or class of existing sources under section 111(d) before it has developed a NSPS for that class of sources under section 111(b). A valid section 111(b) rule is a prerequisite for developing a section 111(d) rule. To comply with this obligation, EPA initially proposed a section 111(b) rule for new electric generating units on April 13, 2012. After receiving 2.5 million comments on this proposal, including comments from WVDEP's Division of Air Quality, EPA decided to withdraw it. EPA published a new proposed 111(b) rule on January 8, 2014.[41] On May 9, 2014, the WVDEP's Division of Air Quality submitted extensive comments on this proposed rule.

Anticipating EPA's development of a section 111(d) rule for existing power plants, the WVDEP developed *West Virginia's Principles to Consider in Establishing Carbon Dioxide Emission Guidelines for Existing Power Plants*, which Governor Earl Ray Tomblin presented to EPA Administrator Regina McCarthy on February 21, 2014. EPA's proposed 111(d) rule was published June 18, 2014.[42] On July 31, 2014, WVDEP staff delivered testimony on behalf on Governor Tomblin at a public hearing on this proposed rule that was held in Pittsburgh, Pennsylvania. On December 1, 2014, the WVDEP submitted extensive comments to EPA on its proposed 111(d) rule, as well as the associated notice of data availability and additional information regarding the translation of emission rate-based CO_2 limits to mass-based equivalents. These comments were prepared by the WVDEP as lead agency, with the assistance of the West Virginia Division of Energy, with regard to renewable energy and energy efficiency, and in consultation with the senior staff of the West Virginia Public Service Commission (WV PSC). The WV PSC input was reflected in these comments, particularly with regard to the effects of the proposed guidelines on the extensive costs that would be incurred by the owners of the EGUs, the impact on retail ratepayers, the negative impacts on the economy of the State due to potential electricity rate increases to West Virginia customers, and the negative impact on the reliability of the power grid.

EPA finalized a carbon dioxide NSPS rule under section 111(b) for new electric generating units ("new" in this case, means construction was begun on the unit after January 8, 2014) concurrently with its finalization of the 111(d) rule for existing electric generating units on October 23, 2015. On the same date, in addition to adopting these two rules, EPA also proposed rules that will establish the federal plan it intends to impose on states that fail to file an approvable state plan. This federal plan rule proposal also includes two sets of proposed model trading rules for states: one to facilitate allowance trading in states that adopt a mass-based state plan and one to facilitate ERC trading in states that adopt a rate-based state plan. The WVDEP also submitted comments on the EPA's proposed federal plan and model state trading rules on January 21, 2016.

Incident to its final 111(d) rule, EPA is also working on guidance governing elements of this rule. The table below is a compilation of the various rules, rule proposals and anticipated guidance EPA has issued or intends to issue as part of its efforts to regulate CO_2 emissions from power plants. These initiatives are discussed in greater detail below.

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41 79 Fed.Reg. 1430 (January 8, 2014).

42 79 Fed.Reg. 34,829 (June 18, 2014).

Table 1: Summary and Status of the EPA Rules & Guidance to Regulate Greenhouse Gases from Power Plants

Rule or Guidance	Status
New EGUs - 40 CFR 60, Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*; applicable to units that commence construction after January 8, 2014 or commence modification or reconstruction after June 18, 2014 § 111(b) CAA authority	Final 80 Fed.Reg. 64661 October 23, 2015 Under legal challenge in the D.C. Circuit, *North Dakota v. EPA*, 15-1381
Existing EGUs - 40 CFR 60, Subpart UUUU, *Emission Guidelines for Greenhouse Gas Emissions and Compliance Timelines for Electric Generating Units* § 111(d) CAA authority	Final 80 Fed.Reg. 64661 October 23, 2015 Stayed - February 9, 2016 Under legal challenge in the D.C. Circuit, *West Virginia v. EPA*, 15-1363
State Mass-based Model Rule - 40 CFR 62, Subpart MMM, *Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014*	Proposed 80 Fed.Reg. 64965 October 23, 2015 Comment period closed Projected to be finalized in summer, 2016
State Rate-based Model Rule - 40 CFR 62, Subpart NNN, *Greenhouse Gas Emissions Rate-Based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014*	
Federal Plan for States Without Approved State Plans – Proposed within 40 CFR 62 Parts MMM and NNN; details were not completely developed.	
Environmental Justice Screening and Mapping Tool (EJSCREEN) – the EPA has incorporated methods of assessing EJ into the § 111(d) rule, including an interactive relative ranking mapping tool.	Guidance Final - August, 2015
Clean Energy Incentive Program (CEIP) – voluntary program for renewable energy (RE) incentive and Energy Efficiency (EE) in low-income communities; will impact allowances and ERCs available for EGUs	Guidance anticipated late spring – summer, 2016
Evaluation, Measurement and Verification (EM&V) Guidance for Demand-Side Energy Efficiency (EE)– Extensive EM&V will be required to ensure that EE savings in rate-based plans are properly quantified and verified. States will have to implement EM&V if a rate-based plan is chosen, or if RE or CEIP set-asides are chosen in a mass-based plan.	EPA draft guidance August 3, 2015 Anticipated to be finalized – Summer, 2016

A. 111(b) Rules for New, Modified and Reconstructed Units

This section summarizes the 111(b) rules for new, modified and reconstructed coal-fired units. These standards apply to newly constructed power plants or to an existing unit that meets certain, specific conditions described in the Clean Air Act which is “modified” or “reconstructed.”

- A ***new source*** is any newly constructed fossil fuel-fired power plant that commenced construction after January 8, 2014.
- A ***modification*** is any physical or operational change to an existing source that increases the source's maximum achievable hourly rate of air pollutant emissions. This standard would apply to units that modify after June 18, 2014.
- A ***reconstructed source*** is a unit that replaces components to such an extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable facility. This standard would apply to units that reconstruct after June 18, 2014.

The EPA established NSPS for two categories of fossil-fuel fired sources: electric utility steam generating units, which typically burn coal, and stationary combustion turbines, which typically burn natural gas. NSPS are based on what EPA determines to be the “best system of emissions reduction” (BSER) for a class of sources.

The final standards for steam units vary depending on whether the unit is new, modified or reconstructed. The EPA asserts that each of these standards is based on the performance of available and demonstrated technology. The final emission limits for new sources are based on highly efficient new coal units implementing a basic version of carbon capture and storage (CCS) – one that would require partial capture of the CO_2 produced in the facility. A new coal-fired power plant is expected to be able to meet the final standard by capturing about 20% of its carbon emissions. At least in part based on this 111(b) rule, no new coalfired power plants are expected to be built in the United States in the foreseeable future. Some have characterized the rule as a ban on new coalfired power plants. As it expressed in comments on the proposed 111(b) Rule,[43] the WVDEP continues to strongly disagree with the EPA’s claim that CCS is commercially available or adequately demonstrated. In contrast to the limits for new units, the final emission limits for modified and reconstructed sources do not require implementation of CCS technology.

The EPA determined that the BSER for new and reconstructed stationary combustion turbines is natural gas combined cycle (NGCC) technology. Different standards apply depending on whether or not the unit provides base load electricity. EPA determines whether a unit is a base load provider by a “sliding scale” approach that considers both design efficiency and sales. This means that the dividing line between what is considered base load and non-base load will change depending on a unit’s nameplate design efficiency. The EPA chose not to set a standard for modified stationary combustion turbines at this time and withdrew the original proposal regarding them.

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43 WVDEP, *Comments On Standards Of Performance For Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units: Proposed Rule 79 Fr 1430, 08 Jan 2014,* May 2014

Table 2: CAA § 111(b) New, Modified, Reconstructed Source Fossil Fuel-Fired Power Plant Emission Performance Standards

§ 111(b) Rule, 40 CFR 60, Subpart TTTT for New, Modified or Reconstructed Sources	
Affected EGU	**CO_2 Emission Standard for steam generating units and IGC that commenced construction after January 8, 2014 and Reconstruction or Modification After June 18, 2014 (lb CO_2/ MWh gross)**
Base Load Combustion Turbines	1,000
Non Base Load	Meet a clean fuels input-based standard
Newly constructed steam generating unit or IGCC	1,400 Supercritical Pulverized Coal (SCPC) Boiler; Requires approximately 20% CCS
Reconstructed steam generating unit that has a base load rating of 2,000 MMBTU/hr or less	2,000
Reconstructed steam generating unit that has a base load rating greater than 2,000 MMBTU/hr	1,800
Modified steam generating unit of IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than:
	1,800 for units with a base load rating greater than 2,000 MMBTU/hr
	2,000 for units with a base load rating 2,000 MMBTU/hr or less

EPA expressed all of the NSPS under section 111(b) as limits based on *gross* generation, while the existing source performance standards it established under section 111(d) are expressed in terms of *net* generation. Gross generation includes all electricity produced by a unit. Net generation excludes from gross generation the amount of electricity that a unit uses to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. The power needed to operate this auxiliary equipment at a unit is known as the unit's parasitic load. The difference between net and gross generation for CCS is quite significant because the necessary equipment for CCS imposes a large parasitic load.

The 111(b) rule is being challenged in the United States Court of Appeals for the District of Columbia in *North Dakota v. EPA*, 15-1381. Issues raised include whether CCS, as a component of EPA's BSER, is "adequately demonstrated" and whether EPA considered technology in its BSER determination that had been funded by the United States Department of Energy, in contravention of the Energy Policy Act of 2005. Some have also asserted that the 111(b) rule is arbitrary and capricious because it amounts to a ban on new coal-fired power. Should the challenges to this rule result in it being vacated, the 111(d) rule for existing plants would also be in jeopardy because a valid 111(b) rule for a class of sources is a prerequisite to regulation of that class of sources under section 111(d).

B. 111(d) Rule for Existing Units[44]

EPA's final section 111(d) rule provides state-specific mandates for CO_2 emissions reductions occurring over a four step interim period from 2022 through 2030. Its goal is a 32% nationwide reduction in CO_2 emissions from existing electric units by 2030. The state limits are expressed both in terms of (1) net CO_2 hourly emissions rates in pounds per megawatt hour (lb CO_2/MWh net) and (2) yearly mass of CO_2 emitted in tons per year. West Virginia's final limits amount to a 37% reduction in the rate of CO_2 emitted and a 29% reduction in the mass of CO_2 emitted in comparison to the 2012 baseline year EPA chose. The 2012 baseline levels plus the interim and final mandated reductions for West Virginia are shown in the table below:

Table 3: Base Line, Interim and Final §111(d) Emission Performance Mandates for WV[45]

Rate-Based CO_2 Emission Performance Mandates for West Virginia (lb of CO_2/MWh net from all affected fossil fuel-fired EGUs)					
Base Line	Interim limit – Step 1	Interim limit – Step 2	Interim limit – Step 3	Interim limit	Final limit
(% reduction from 2012 baseline)					
(2012)	(2022-2024)	(2025-2027)	(2028-2029)	(2022-2029)	(2 yr. blocks starting with 2030-2031)
2,064	1,671	1,500	1,380	1,534	1,305
n/a	(19%)	(27%)	(33%)	(26%)	(37%)
Mass-Based CO_2 Emission Performance Mandates for West Virginia *(tons of CO_2 from all affected fossil fuel-fired EGUs)*					
Base Line	Interim limit – Step 1	Interim limit – Step 2	Interim limit – Step 3	Interim limit	Final limit
(% reduction from 2012 baseline)					
(2012)	(2022-2024)	(2025-2027)	(2028-2029)	(2022-2029)	(2 yr. blocks starting with 2030-2031)
72,318,917	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
n/a	(13%)	(22%)	(26%)	(20%)	(29%)

The limits in the above table are depicted in graphic form in the figures below.

[44] This section provides an overview of the section 111(d) rule. The rule presents a number of policy choices that can be made in development of a state plan. These policy choices are discussed below in the Policy Choices discussion starting on page 86.

[45] 80 Fed. Reg. 64824-5 (October 23, 2015).

Figure 3: West Virginia's Rate Limits

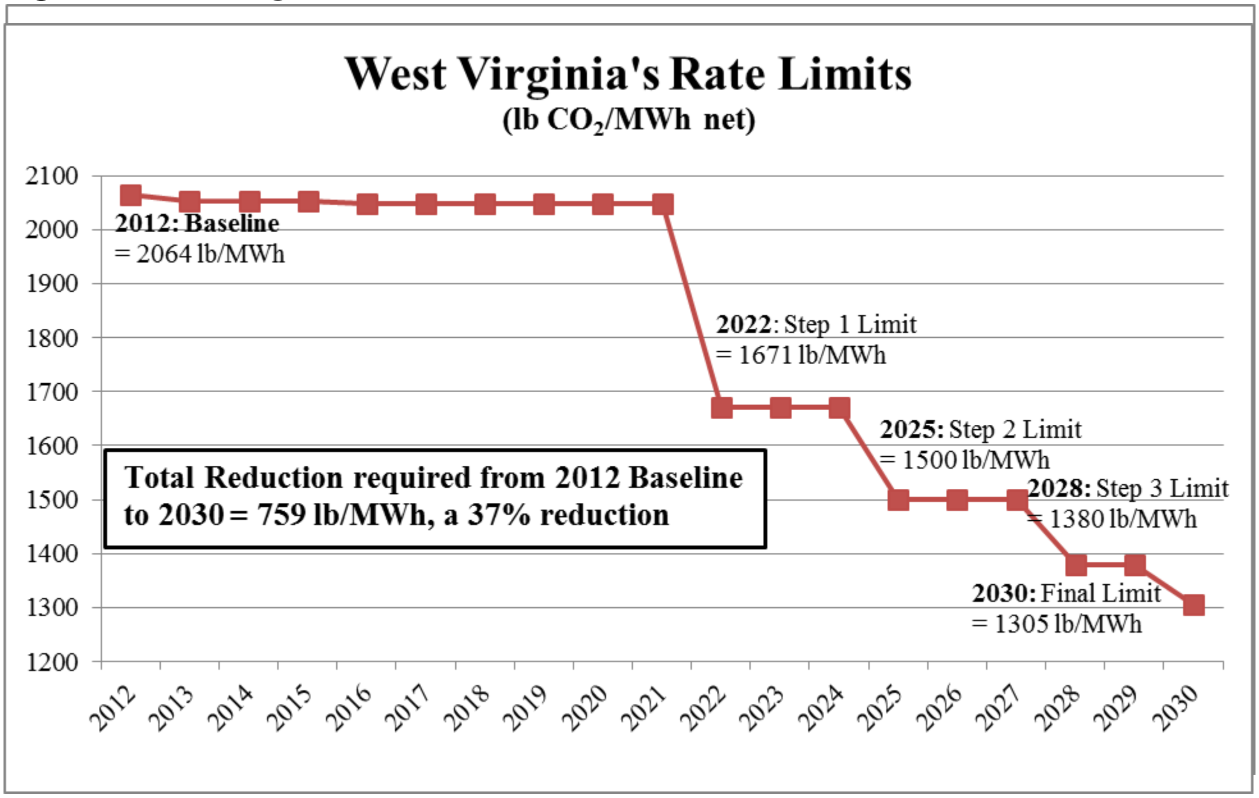
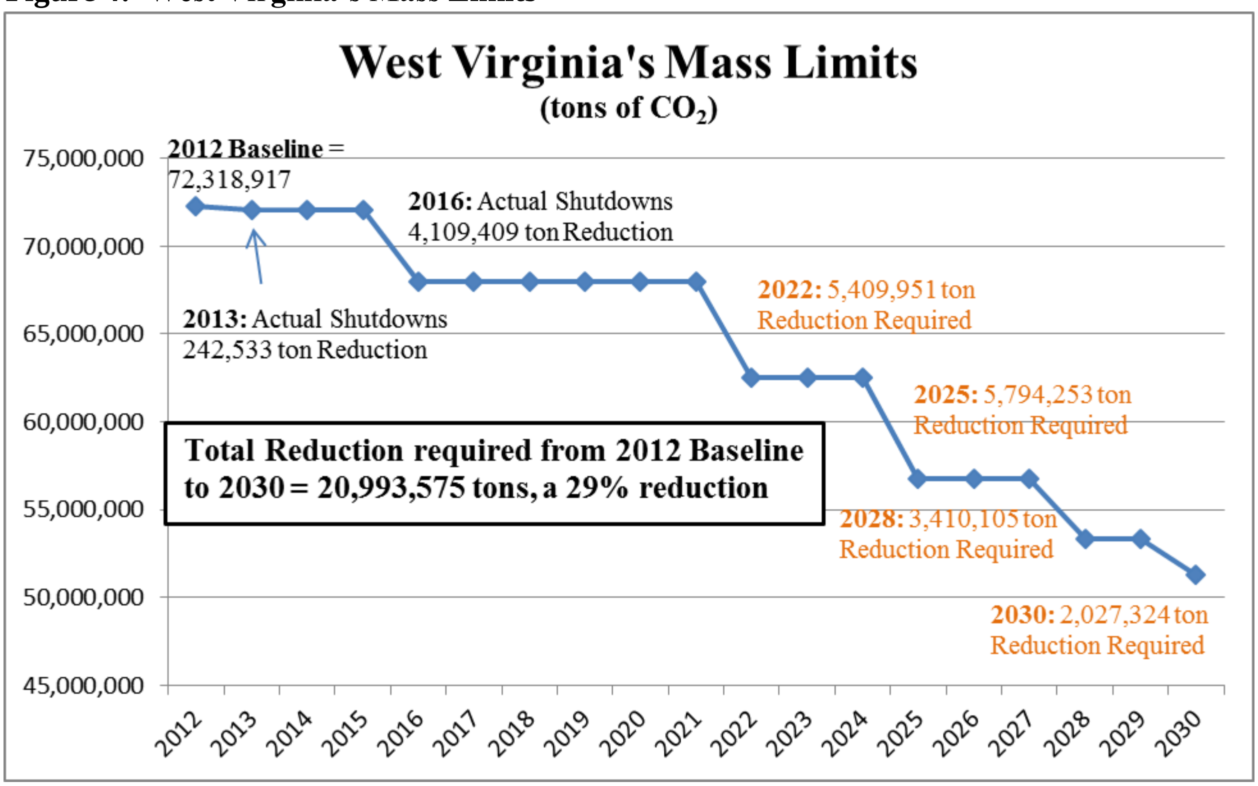


Figure 4: West Virginia's Mass Limits



BSER and State Limits

In developing the BSER for this 111(d) rule, EPA moved away from its historic Clean Air Act role of regulating emissions of pollutants at the sources of those emissions. Instead of focusing on source specific pollution control measures as in the past, EPA established a "source subcategory wide basis"[46] BSER which looks to manage and reduce emissions from this source category as a whole by forcing this class of sources into:

> (i) direct investment in efficiency improvements and in lower- and zero-carbon generation, (ii) cross-investment in these activities through mechanisms such as emissions trading approaches, where the state-established standards of performance to which sources are subject incorporate such approaches, and (iii) reduction of higher-carbon generation.[47]

Instead of looking to emission control measures that can be implemented at a coal-fired electric generating unit to reduce its emissions, the EPA rule seeks to compel such units to lead a fundamental transformation in the way electricity is generated.

The emissions limits EPA established are based on emissions reductions EPA found to be available from three "building blocks" that were part of its BSER: Building Block 1 - increasing efficiency through heat rate improvements at individual electric generating units; Building Block 2 - shifting power generation from higher CO_2 emitting sources to lower emitting natural gas combined cycle units; and, Building Block 3 - shifting power generation from higher CO_2 emitting sources to zero CO_2 emissions sources.[48] Based on the application of these factors, EPA concluded that the final limits for emissions should be a rate of 1,305 lb CO_2/MWh from coal-fired units and 771 lb CO_2/MWh from gas-fired units.[49] EPA calculated state specific targets based on each state's blend of coal and gas-fired power generation. Because all of the "affected units" in West Virginia are coal units, West Virginia's limit is the same as that for coal units, 1,305 lb CO_2/MWh. Based on a state's emission rate limit and its total tons of CO_2 emissions in the baseline year, 2012, EPA also calculated a mass-based limit for each state. West Virginia's final mass-based limit is 51,321,890 tons.

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[46] 80 Fed.Reg. 64719 (October 23, 2015).

[47] 80 Fed.Reg. 64717 (October 23, 2015).

[48] Most of West Virginia's coal fired units were designed to serve baseload power demand and are most efficient at converting heat into electric power when they operate continuously at or near capacity. They are less efficient when cycling in and out of full capacity. The EPA objective of transforming the system by shifting power generation away from coal units (Building Blocks 2 and 3) would cause more cycling of coal units. Accordingly this objective operates in tension with the Building Block 1 goal to increase efficiency at the unit.

[49] Historically, performance standards that have been applied to new sources under section 111(b), which can readily take new performance standards into account in their initial design, have been much more stringent than those imposed on existing sources under 111(d), which are already built, in operation, and have much less flexibility in the addition of new emissions controls. However, EPA counterintuitively, and perhaps illegally, established less stringent 111(b) emission rates for new coal units (1,400 ln CO_2/MWh) and new gas units (1,000 lb CO_2/MWh for base load units) than it did for existing coal units (1,305 lb CO_2/MWh), and gas units (771 lb CO_2/MWh).

Trading as a Means to Comply

As part of the system for effecting this change, the EPA rule establishes a form of "currency" which electric generating units must acquire in order to comply. For states that choose to adopt a mass-based plan, the units of this currency are called allowances. For states that adopt a rate-based plan, the units are called emission rate credits (ERCs). In either system, a generating unit must possess enough currency at the end of a compliance period to enable it to meet the limit for that period. A state plan may allow trading of this currency on an instate-only, a multistate or a national basis. Generally, the wider the market for trading is, the lower the per-unit cost of the currency is anticipated to be. The mass and rate-based markets are structured differently, but both are intended to encourage movement away from high carbon sources of electricity to lower emitting sources.

Mass-Based Plan – Trading Allowances

In the mass-based scenario, for each compliance period a state is given a number of allowances that is equal to the number of tons of CO_2 that has been established as its limit for that period. For each successive compliance period leading to the final limits in 2030, the number of allowances a state is given is reduced. States decide how to distribute these allowances. They can be sold or given away. A state can use the manner in which allowances are distributed to encourage a variety of policy outcomes. As stated above, at the end of a compliance period each electric generating unit must surrender a number of allowances equal to the number of tons of CO_2 it emitted during that period. The EGU can either limit its operations to the number of allowances it receives from the state or it can purchase additional allowances on the market to support additional operation and the additional emissions that go with it. The price for allowances on the market is a factor in determining which units will operate and for how long. It also helps to determine which measures an individual plant can take to reduce CO_2 emissions are cost effective. It is anticipated that shifts in energy production across the country away from higher carbon emitting sources to non-emitting renewable and nuclear energy and will provide a viable market for allowances for the coal and gas-fired generation that remains.

Mass-Based Plan – Set-Asides

In addition to the basic features of the mass-based allowance market, EPA has included some additional features that are supposed to be "options" for states in the program. First, there are three "optional" set-aside programs for mass-based programs, only two of which apply in West Virginia, the renewable energy (RE) set-aside and the CEIP set-aside. Participation in a set-aside program would require a state to reduce the number of allowances it makes available to EGUs by the number of allowances that are set-aside. The allowances that are set-aside are then distributed to others in order to provide them with value that subsidizes the EPA-chosen policy outcomes to which these others contribute. For example, the RE aside would take up to 5% of a state's available allowances and distribute them to developers of new renewable, zero carbon energy. These renewable energy producers can then sell the allowances they have earned to higher carbon energy sources which need the allowances to comply.

Another set-aside of approximately 5% of a state's available allowances would provide allowances for what EPA calls the Clean Energy Incentive Program (CEIP).[50] The CEIP would make the allowances available to: (1) producers of new wind and solar RE during the years 2020 and 2021 and (2) projects that make energy efficiency (EE) improvements in low income communities in the same time frame. An additional feature of the CEIP is that EPA will match the allowances a state awards to a RE project under the CEIP with one additional allowance for each MWh of higher carbon electricity displaced. EPA will match state awards to low income EE projects under the CEIP with two additional allowances for each MWh of higher carbon electricity avoided through the EE improvements. As with the RE set-aside, the recipient of allowances awarded through the CEIP program can then sell them to EGU owners who need them for compliance. The number of matching allowances EPA provides in the CEIP may slightly inflate the number of allowances that are available when the first interim requirements start in 2022. The CEIP is also intended to jump start the allowance marketplace by providing a readily available pool of them when compliance starts in 2022. States are free to develop other set-aside programs to encourage other policy goals.

Mass-based Plans – New Source Complement

Another "option" EPA included for states that utilize a mass-based state plan is what it calls the "new source complement" (NSC). Under the NSC option, new sources would be included in the state's pool of existing sources and, just as with existing sources, they would be required to have sufficient allowances to cover the number of tons of CO_2 they emit. To encourage states to utilize this option, EPA would allot additional allowances, called the new source complement, to participating states. Under the NSC, West Virginia would receive 1.04% more allowances than what is allotted for existing sources, alone.

A real world example helps provide an understanding of whether opting for the NSC is beneficial. The West Virginia Division of Air Quality (DAQ) has issued a permit for a new gas-fired power plant in Marshall County. DAQ has received a permit application for a new gas-fired plant in Brooke County and has had pre-application meetings with the developer of another proposed gas-fired power plant in Harrison County. The number of additional allowances West Virginia would receive via the NSC will not cover the emissions from the one unit for which a permit has been issued. If the state opted for the NSC, all of these plants would be additional competitors in the marketplace for allowances. If the state does not opt for the NSC, none of these plants would need allowances. Instead, all of them would be regulated under EPA's 111(b) rule as new sources. Because all of them will employ the newer, highly efficient natural gas combined cycle design that is capable of complying with the emissions rate limits of EPA's 111(b) rules for new gas-fired units, these plants would not be expected to face any difficulty in complying with the 111(b) rule.

Mass-based Plans – Leakage

For some states, the NSC, the RE set-aside or other set-asides may not be optional. EPA has determined that at least in part due to the way it has developed its suite of rules under section 111 for the fossil fuel-fired electric industry, there is some potential incentive for power

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50 A version of the CEIP tailored to ERC trading is also a feature of rate-based plans under the 111(d) rule.

production and the emissions that go with it to be shifted from some existing 111(d) sources (most particularly, existing natural gas combined cycle plants), to new sources of electric generation that are regulated under 111(b). EPA calls this potential shift of emissions from the pool of existing sources regulated under 111(d) to new sources regulated under 111(b) "leakage". EPA is requiring states it believes have the potential for leakage to make a demonstration that this potential has been avoided in their state plans. Two acceptable ways of making this demonstration, according to EPA, are to either adopt the NSC or the RE set-aside. Although EPA's discussion of the concept of leakage is much less than clear, West Virginia does not have any existing NGCC units, so the WVDEP does not believe that leakage will be an issue for West Virginia.[51]

Rate-based Plan – Trading ERCs

In a rate-based state plan, the tradeable units that coal-fired EGUs must acquire in order to comply are called emissions rate credits (ERCs). The emissions rate limit a coal-fired power plant must meet under the EPA's rule is well below the rate any existing coal-fired unit in West Virginia has attained (compare 2,064 lb CO_2/MWh to the final West Virginia 111(d) limit of 1,305 lb CO_2/MWh). The primary way a coal-fired unit can meet its rate-based limit is through the acquisition of ERCs. The ERCs a unit possesses are used to adjust its emissions rate. On a basic level, an emissions rate is determined from a relatively straightforward arithmetic calculation. The number of pounds of CO_2 the unit has emitted during a compliance period is the numerator in the calculation. It is divided by the denominator, which is the number of MWh of electricity produced during that period. In the rate-based scenario, the ERCs a unit has acquired are treated as additional megawatt hours that are added to the denominator in this calculation. When the number of MWh plus ERCs in the denominator is large enough to yield a compliant rate (for coal-fired units – 1,305 lb CO_2/MWh, or less) for the unit, the unit is in compliance. The equation used in the rate-based compliance calculation is shown below:

$$CO_2\ emission\ rate = \frac{total\ pounds\ of\ CO_2}{total\ MWh\ generated + total\ ERCs}$$

Rate-based Plans – Generating ERCs

One ERC can be earned for each megawatt hour of zero CO_2 emissions power produced or for each megawatt hour of emissions avoided through energy efficiency measures. It is also possible for NGCC units to earn ERCs when their actual emissions rate is lower than the 111(d) rule's target for emissions from such units. In this case, a calculation must demonstrate how the benefit of lower actual emissions from the unit in comparison to the 111(d) target for emissions from the unit equates to zero CO_2 emissions in MWh. Once earned, ERCs can be sold in the marketplace to buyers, presumably owners of higher carbon emitting units which need the ERCs in order to calculate a compliant emissions rate.

[51] EPA has verbally confirmed this both to representatives of the DAQ and to air quality regulators in other states that are similarly situated. However, the WVDEP is unaware of any written confirmation of this by EPA.

Unlike the allowances that are traded in the mass-based scenario, ERCs do not exist until they are generated and approved by a totally new bureaucracy that must be created in government for this purpose. Under EPA's rule, a project for generation of ERCs must apply for and receive government approval before the project begins. It must demonstrate a rigorous means of documenting the value it will produce in MWh. Then, after results are obtained, the project must go back to the government to demonstrate the results it has produced, before it can earn a marketable ERC. Independent verifiers and a complicated process of EM&V are contemplated. The government must track ERCs that have been awarded from cradle to grave. There must be a means of assuring that ERCs from one state are not approved and used in multiple states. A means of appealing government decisions on initial project approval and the actual awarding of ERCs must be provided. In addition to all of this, there must also be a process for cancelling, after the fact, ERCs that may have been awarded, sold and used by the owner of an electric unit that are later determined to be bogus. The complexity of the ERC approval process and the necessary EM&V may cause some states for which a rate-based plan might otherwise make more sense than a mass-based plan to be reluctant to adopt a rate-based plan.[52]

Rate-based Plans – Compliance Illustration

In 2012, the units at the John Amos power plant near Winfield, West Virginia produced 12,969,046 MWh of electricity and 13,060,997 short tons of CO_2 emissions. Its emissions rate was 2,014 lb CO_2/MWh. If the John Amos facility was able to achieve a 2% heat rate improvement through physical changes to the plant or changes in work practices, this would bring its emissions rate down to 1,974 lb CO_2/MWh. The emissions rate limit for John Amos in the initial Step One compliance period from 2022 to 2024 is 1,671 lb CO_2/MWh. The total of all wind power generation in West Virginia in 2012 was 1,286,024 MWh. This amount of wind power would not provide enough ERCs to bring the Amos facility into compliance with its Step One limit. Over five times the state's 2012 wind power production would be required to bring Amos into compliance with the final 2030 rate-based limit of 1,305 lb CO_2/MWh. Importantly, the state's existing wind power cannot generate ERCs under the EPA rule. Only new wind power or additions to existing wind capacity can generate ERCs.

Comparison of Proposed and Final 111(d) Rules

When HB2004, which required this feasibility study and comprehensive analysis, was being considered and adopted by the Legislature, the 111(d) rule only existed as a proposal. The announcement of the content of the final rule was several months away at that time. Because the Legislature may benefit from a comparison showing how the final rule differs from the draft rule that was before it when HB2004 was adopted, the WVDEP offers the chart below.

52 In states with mass-based plans, similar onerous EM&V requirements would be necessary if the CEIP or RE set-asides are included as part of the state plan.

Table 4: Comparison of Proposed and Final 111(d) Rule

	Issue	Proposed Rule	Final Rule
Timeline	Compliance period	From 2020 to 2030 During a ten-year period from 2020 to 2029 states achieve interim targets. Final limit to be met in 2030 and later.	From 2022 to 2030, with three interim steps 1. 2022-2024 2. 2025-2027 3. 2028-2029 During each step there is a different interim limit. Final limit to be met in 2030 and later.
	State Plan Submittal	- State Plans due in 2016 - State Plans with 1-year extension due in 2017 - Multi-State Plans due in 2018	– State Plan or Initial plans due September 6, 2016 - Upon an Initial Submittal, states obtain an extension of up to 2 years to file a final plan by September 6, 2018
WV Limits	2012 Baseline Rate	2,064 lb CO_2/MWh	2,064 lb CO_2/MWh
	Interim – Rate-based	1,748 lb CO_2/MWh, average over 10 years	2022-2024 1,671 lb/MWh 2025-2027 1,500 lb/MWh 2028-2029 1,308 lb/MWh
	Final – Rate-based	1,620 lb CO_2/MWh	1,305 lb CO_2/MWh
	2012 Baseline Mass	72,318,917 tons	72,318,917 tons
	Interim – Mass-based	Not Stated	2022-2024 62,557,024 tons 2025-2027 56,762,771 tons 2028-2029 53,352,666 tons
	Final – Mass-based	Not Stated	2030 + 51,325,342 tons
Trading	Geographic Extent of Trading Area	State Only, plus Regional with an Interstate Agreement	Instate Only, Multistate and National
BSER Building Blocks		Four Building Blocks 1. 6% heat rate improvement at fossil units 2. Increase utilization of NGCC (gas) units to 70% & re-dispatch to them from coal units 3. Increase RE generation & re-dispatch to it from coal units 4. Increase EE	Three Building Blocks 1. 4.3% heat rate improvement at fossil units 2. Increase utilization of NGCC (gas) units to 75% & re-dispatch to them from coal units 3. Increase RE generation & re-dispatch to it from coal units

Current Status of 111(d) Rule

The State of West Virginia is lead plaintiff in a suit challenging the legality of the 111(d) rule in the United States Court of Appeals for the District of Columbia in *West Virginia v. EPA*, 15-1363. The suit includes a multitude of arguments as to why the EPA rule is unlawful.[53] West Virginia and others challenging the rule have filed initial briefs in the case and EPA has responded. The case is set for oral arguments on June 2, 2016.

As reported above, the United States Supreme Court granted a stay of the 111(d) rule on February 9, 2016. As a result, all deadlines in the rule are suspended while the stay is in effect.

C. Rules to Establish a Federal Plan and Model State Trading Rules

In a move that could be interpreted as a preemptive shot at states that are considering the "just say no" approach to state plan development under section 111(d), EPA proposed a rule to establish a federal plan for regulation of existing power plants under section 111(d), concurrently with its finalization of the 111(b) and 111(d) rules themselves. This will enable EPA to have a federal plan on the shelf and at the ready should states fail or refuse to submit an approvable plan by the deadline for doing so. As a proposed rule, perhaps little should be said about this rule. However, there are just a few observations that may be useful at this point. First, EPA proposed rules for both a rate-based federal plan and a mass-based federal plan but indicated that it only intended to finalize one of the two. As to this choice, EPA indicated that it was leaning toward the mass-based approach. The prevailing thought among those who have studied these developments closely has been that carbon intense states like West Virginia generally fare better under the mass-based approach. However, as the rule is proposed, EPA would subscribe to all three of the set-asides in the 111(d) rule. This diverts the largest number of allowances away from the EGUs which need to them to comply and places them in the hands of others to be sold in the marketplace (in West Virginia's case, this would amount to 10.6% of the state's total allowances in the first compliance period and 5% thereafter). One other item from the proposal that is noteworthy is the possibility that, when a coal-fired unit retires or is otherwise forced to leave the market, EPA may cancel the allowances that were otherwise allocated to that unit instead of making them available to the remaining EGUs, thereby reducing the pool of available allowances. This is not the approach that EPA proposed in the rule, however, EPA indicated that it was considering this possibility and taking comment on it. EPA indicated that it will not finalize its federal plan until a state fails to submit an approvable state plan.

As part of the same rule proposal with the federal plan, EPA proposed two sets of model trading rules for states, one for rate-based plans and one for mass-based plans. States that adopt the mass-based model rules would have the opportunity to trade allowances with all other states that have adopted them. Similarly, states that adopt the rate-based model rules would have the

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53 These arguments can be found in the opening briefs filed in the case which can be found at: http://www.ago.wv.gov/publicresources/epa/Documents/Opening%20Core%20Brief%20-%20file-stamped%20%28M0119247xCECC6%29.pdf and http://www.ago.wv.gov/publicresources/epa/Documents/Record-based%20brief%20-%20file-stamped%20%28M0119267xCECC6%29.pdf Last visited April 15, 2016.

opportunity to trade ERCs with all other states that have adopted them. This could greatly simplify state plan development for states that desire the ability for their EGUs to trade in the largest possible market. States would be able to make the decisions on basic plan design and, as to trading, simply adopt the model rules. As the 111(d) rule was proposed, it allowed either instate trading, which is not conducive to the economies of scale a larger market provides, or required states to negotiate regional pacts with other states in which the subject states would have to agree on all combinations of state plan options, plus trading rules in the regional market and a combination of all of the individual state limits into a region-wide limit. Besides being both unwieldy and impractical to pull off in the amount of time available, the pacts in this regional approach may have also required the consent of Congress under the Compact Clause of the Constitution. This should all be avoided with adoption of the model state trading rules. EPA intends to do this sometime in summer, 2016. Its final decisions on the state trading rules may also shed some light on what it is likely to do in a final federal plan rule.

D. Guidance on the CEIP and EM&V

Even though the CEIP and provisions for EM&V are part of the 111(d) rule that EPA finalized on October 23, 2015, EPA has indicated that it is developing guidance governing the details of each of them. These details may make a difference in the desirability of the CEIP as a program option and in the decision as to whether state program options that might require EM&V should be adopted. EPA guidance in both of these areas is expected to be complete in the late spring – summer of 2016.

3. Profile of the Electric Generation Industry

In making decisions on a state plan, West Virginia's policy makers may benefit from a profile of the industry and the facilities subject to the EPA rule in West Virginia and a perspective on how they fit into the overall system for generation and delivery of electric power. In addition to the benefits of having this perspective in making the broader policy decisions concerning a state plan, an understanding of the power sector may be particularly useful in consideration of the various options for allocating allowances in a mass-based trading program. Considerations in allocation of allowances are discussed in more detail below in the section on Policy Choices, starting on page 86. This section focuses on generation and delivery of power. In the next section, the regional power markets in which West Virginia's power producers compete are described.

A. Electric Generation in the United States

Most electricity in the U.S. is generated by burning fossil fuels. In 2014, coal accounted for approximately 39% of the four (4) million Gigawatt-hours (GWh) of electricity generated in the United States, natural gas accounted for 27%, and petroleum accounted for less than 1%. Nuclear power accounted for about 19%, and renewables – hydropower, wind power, biomass, geothermal power and solar power – accounted for 13%.[54]

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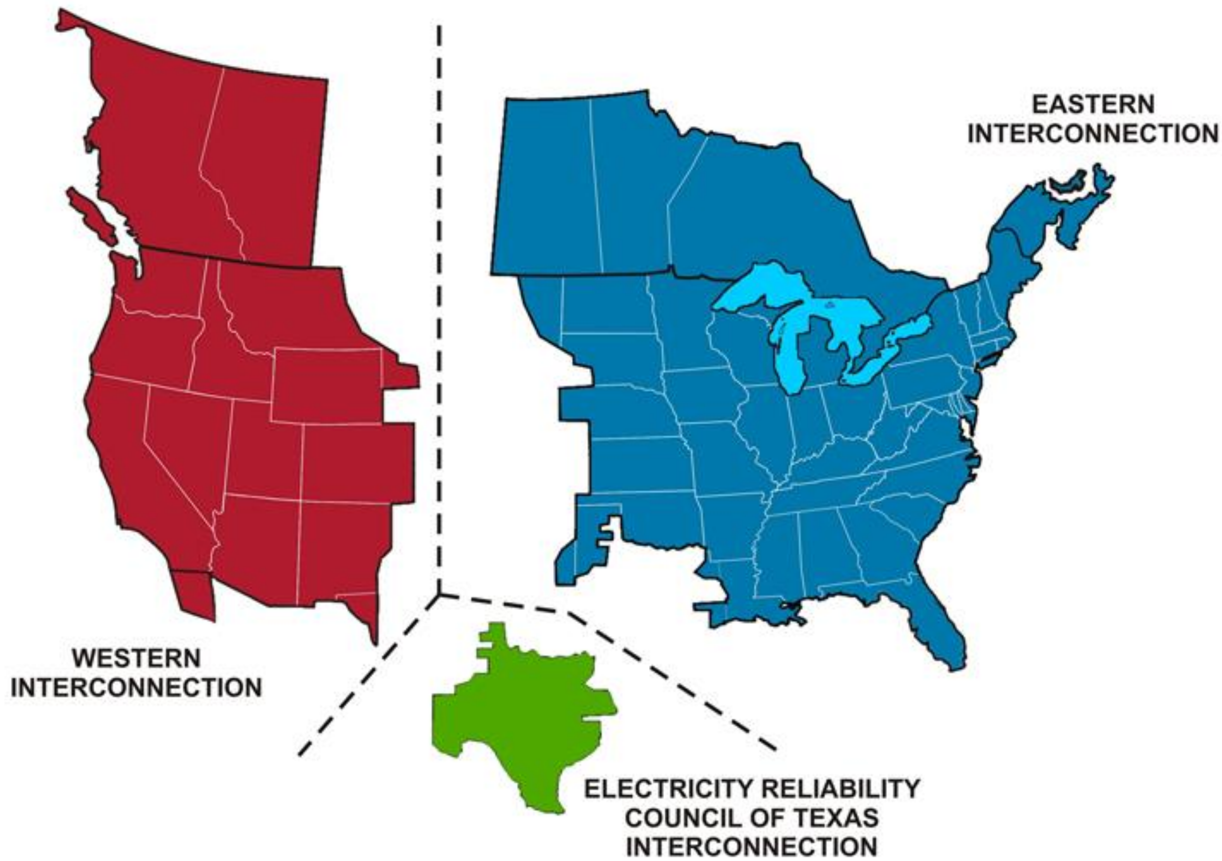
[54] EIA, http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states

Electric power in the United States is transmitted and delivered via three (3) regional synchronized power grids, the eastern, western and Texas interconnections. The eastern interconnection spans the eastern United States from the Atlantic coast to the Rocky Mountains. The western interconnection reaches from the Rockies to the Pacific coast and includes a small part of northern Mexico. The Texas interconnection, as name suggests, covers much of Texas. These interconnects are linked to each other as well as to parts of Canada to the north and Mexico to the south.

Figure 5: North American Electric Reliability Corporation Interconnections

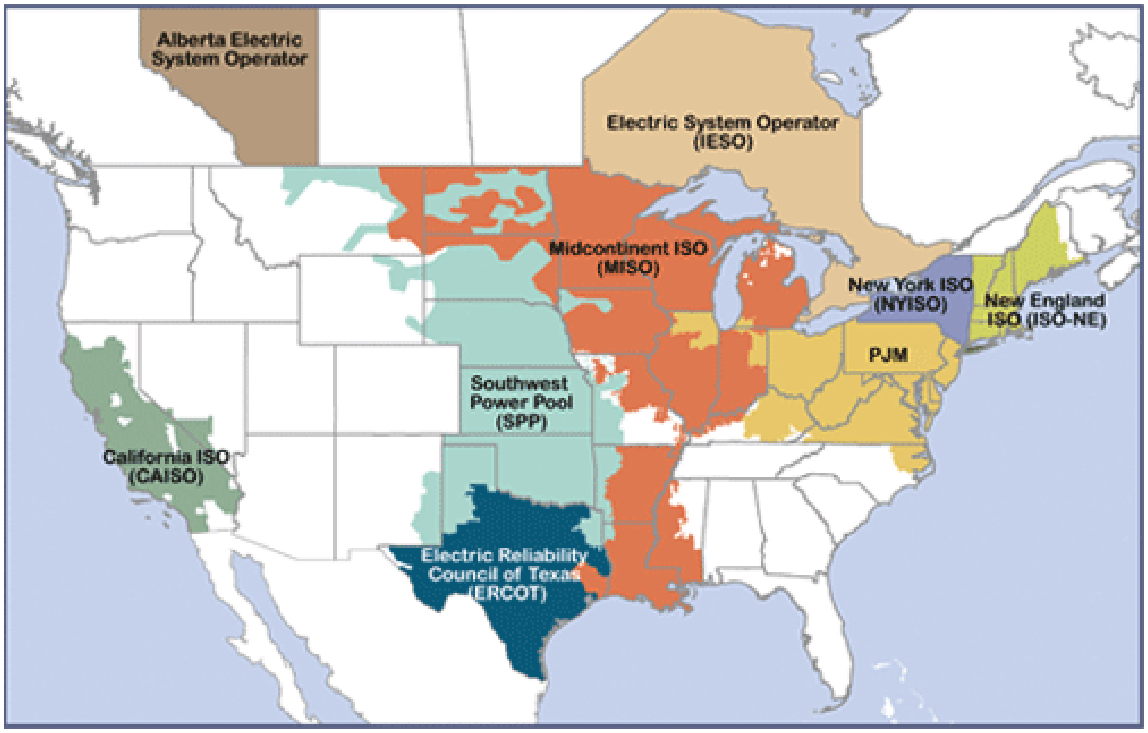


Source: https://www.e-education.psu.edu/geog469/sites/www.e-education.psu.edu.geog469/files/images/NERC_Interconnection_1A.jpg Last visited April 15, 2016.

West Virginia is entirely within the eastern interconnection. West Virginia also lies entirely within the region of the eastern interconnection in which power markets and distribution are managed by the regional transmission organization (RTO), PJM Interconnection. The PJM region includes all or parts of 13 states and the District of Columbia.[55]

55 PJM, "Who We Are," http://www.pjm.com/about-pjm/who-we-are.aspx. Retrieved March 28, 2016.

Figure 6: Independent System Operators Regional Transmission Organization Operating Regions



Source: http://www.ferc.gov/industries/electric/indus-act/rto.asp Last Visited March 31, 2016.

B. Electric Generation in West Virginia

In 2014, coal-fired electric power plants accounted for 95.5% of West Virginia's net electricity production, and renewables – primarily hydropower and wind power – contributed 3.5%. Natural gas-fired power plants accounted for the remaining 1%.[56] Based on EIA records, 15% of West Virginia's coal production from 2010-2014 was consumed in West Virginia power plants that are subject to the EPA rule. Fifty-five percent of state coal production in that time was exported to other states. Most of this coal was burned in power plants in those states that are subject to the EPA rule. The remaining 30% of West Virginia's production was exported internationally. In the same period of time, coal produced in West Virginia comprised 54% of the coal burned in West Virginia power plants.

Historically, the coal-fired units in West Virginia have operated as "base load" units. Base load units serve the constant, minimum requirements of the region and the country for power. Because base load units operate at close to their design capacity at all times when maintenance is not being performed, they are generally very efficient and provide the power at the lowest cost. Recently, low natural gas prices have enabled gas-fired units to take a greater share of base load power, causing some coal-fired units to operate more in the nature of "load

56 EIA, http://www.eia.gov/state/?sid=WV

following" units. Load following units occupy the next tier in the order of economic dispatch and are called upon as power demand grows during the daytime and early evening or on the days of the week when demand is higher. Cycling in and out of optimal operating conditions causes load following units to operate less efficiently than if they were operating continuously near their design capacity. Peaking power plants, or "peakers" only operate during the times of highest demand. The three existing gas-fired power plants in West Virginia all serve peak load.

All of the coal-fired units in the state are "affected units" that are subject to regulation under the EPA rule. Although some natural gas facilities are regulated as "affected units" under EPA's rule, e.g., natural gas combined cycle units, none of the existing gas facilities in the state are "affected units" subject to the EPA's 111(d) rule. All of the natural gas-fired units operating in West Virginia are simple cycle combustion turbine facilities – the Big Sandy Peaker Plant, Ceredo Generating Station and Pleasants Energy. The wind and hydro power producers emit no CO_2 therefore, they are not regulated under this rule.

There were sixteen (16) coal-fired power plants operating in West Virginia in 2012, the baseline year the EPA used in the 111(d) rule. Six (6) of these plants have subsequently retired. Figure 7 shows the location of the operating coal-fired plants. Table 5 lists the units and their current status.

Figure 7: West Virginia Coal-Fired Power Plants

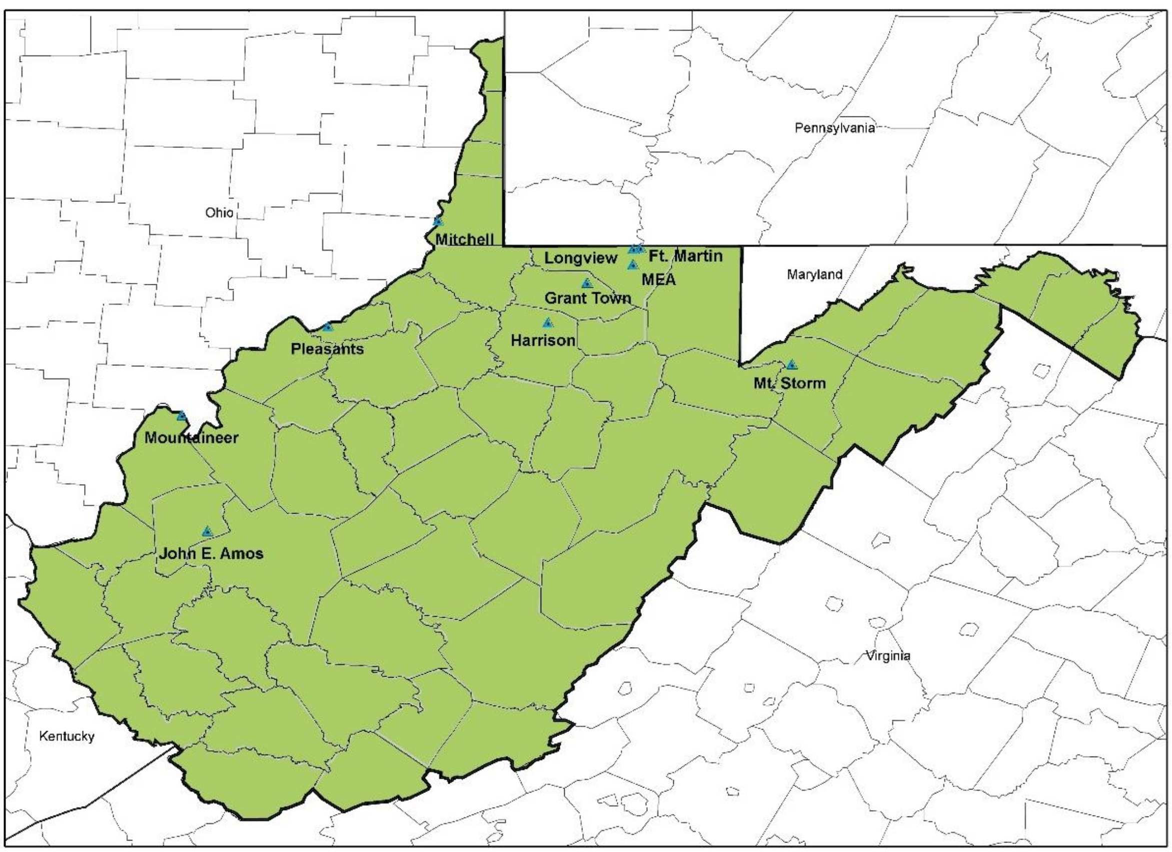


Table 5: West Virginia EGUs Subject to the § 111(d) Rule

Company	Plant	Unit	Nominal Capacity (MW)	Fuel	WV PSC Regulated?	Status
Appalachian Power Company **(AEP)**	Kanawha River	1	220	Coal	Yes	Retired 2015
		2	220	Coal	Yes	Retired 2015
	Kammer	1	200	Coal	Yes	Retired 2015
		2	200	Coal	Yes	Retired 2015
		3	200	Coal	Yes	Retired 2015
	Philip Sporn	11	153	Coal	Yes	Retired 2015
		21	153	Coal	Yes	Retired 2015
		31	153	Coal	Yes	Retired 2015
		41	153	Coal	Yes	Retired 2015
	John E. Amos	1	816	Coal	Yes	Operating
		2	816	Coal	Yes	Operating
		3	1300	Coal	Yes	Operating
	Mountaineer	1	1300	Coal	Yes	Operating
Wheeling Power Company **(AEP)**	Mitchell	1	800	Coal	Yes	Operating
		2	800	Coal	Yes	Operating
Monongahela Power Company **(First Energy)**	Albright	1	73	Coal	NA	Retired 2012
		2	73	Coal	NA	Retired 2012
		3	137	Coal	NA	Retired 2012
	Rivesville	5/7	37	Coal	NA	Retired 2012
		6/8	88	Coal	NA	Retired 2012
	Willow Island	1	54	Coal	NA	Retired 2012
		2	181	Coal	NA	Retired 2012
	Fort Martin	1	552	Coal	Yes	Operating
		2	555	Coal	Yes	Operating
	Harrison	1	640	Coal	Yes	Operating
		2	640	Coal	Yes	Operating
		3	640	Coal	Yes	Operating
Allegheny Energy **(First Energy)**	Pleasants	1	650	Coal	No	Operating
		2	650	Coal	No	Operating
VEPCo **(Dominion)**	Mount Storm	1	533	Coal	No	Operating
		2	533	Coal	No	Operating
		3	521	Coal	No	Operating
AmBit	Grant Town	1A&1B	80	Waste Coal	No	Operating
NRG	MEA	1A&1B	50	Waste Coal	No	Operating
GenPower	Longview	1	700	Coal	No	Operating

Appalachian Power (Amos and Mountaineer power stations), the Mitchell power station, and Monongahela Power (Ft. Martin and Harrison power stations) are each part of investor-owned, vertically integrated utility companies that are regulated by the WV PSC. The Mitchell power station is half owned by Wheeling Power and half owned by Kentucky Power. Appalachian Power, Kentucky Power and Wheeling Power are subsidiaries of American Electric Power (AEP). Monongahela Power is a subsidiary of First Energy Corp.

The Pleasants and Longview power stations are merchant power plants. Merchant power plants are funded by investors and sell electricity in the competitive wholesale power market. Merchant power plants do not serve specific retail consumers, therefore, they are not regulated by the WV PSC and consumers are not obligated to pay for the construction, operations, or maintenance of these plants. The Pleasants power station is owned by Allegheny Energy Supply, a First Energy subsidiary. Longview is owned by GenPower.

The Grant Town and Morgantown Energy Associates (MEA) power stations are qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA). Grant Town is a small power production facility (80 MW) whose primary energy source is abandoned coal waste. MEA is a cogeneration facility (50 MW), also known as a combined heat and power system (CHP), that sequentially produces steam and hot water for West Virginia University (WVU) and electricity for the grid. It utilizes coal waste as its primary fuel source. By burning this coal waste, the MEA and Grant Town facilities are providing an environmental benefit by eliminating this coal waste as source of Acid Mine Drainage. Approximately 80% of all building space at WVU is heated by steam from MEA. WVU does not have a readily available backup for the steam and hot water provided by MEA at most locations. A 2010 feasibility study commissioned by WVU estimated the cost to replace the steam from MEA to be over $30 Million. This cost is believed to have risen since then due to inflation. Both the Grant Town and MEA facilities have power purchase agreements with Monongahela Power Company.

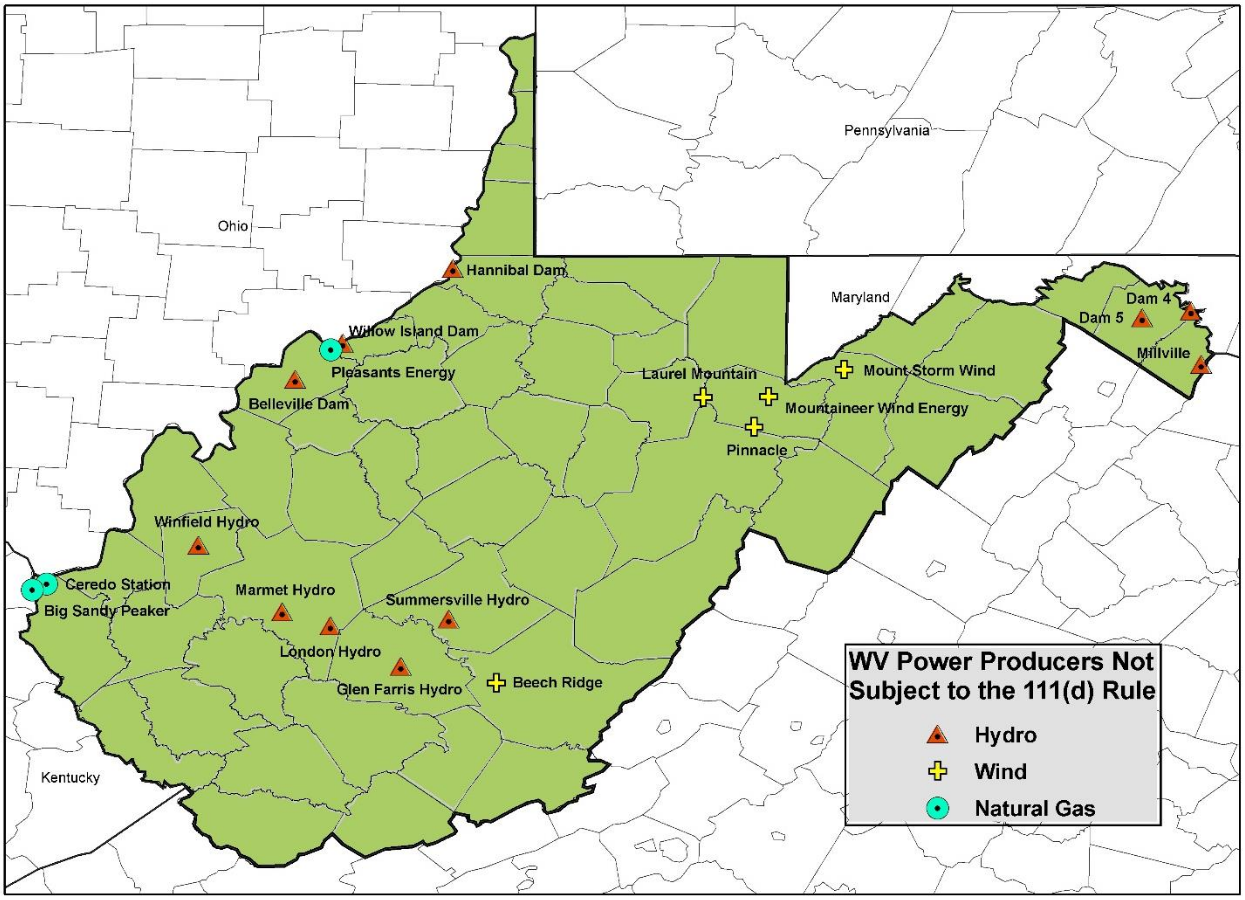
The Mount Storm power station is owned by VEPCo, a subsidiary of Dominion Resources, a vertically integrated utility in Virginia and North Carolina.

West Virginia power producers not subject to the EPA rule are listed below.

Table 6: West Virginia Power Producers Not Subject to the 111(d) Rule

Generating Plant	Fuel Source	Ownership	Nameplate Capacity (MW)
Laurel Mountain	Wind	AES Wind Generation	98
Beech Ridge	Wind	Beech Ridge Energy	100
Mountaineer Wind Energy	Wind	Florida Power and Light	66
Mount Storm Wind	Wind	Nedpower Mount Storm	264
Pinnacle Wind	Wind	Edison Mission	55
Dam 4	Hydro	Allegheny Energy Supply	2
Dam 5	Hydro	Allegheny Energy Supply	1
Millville	Hydro	Allegheny Energy Supply	3
Belleville Dam	Hydro	American Municipal Power –Ohio	42
Willow Island Dam	Hydro	American Municipal Power -Ohio	44
Marmet Hydro	Hydro	Appalachian Power	14
London Hydro	Hydro	Appalachian Power	14
Winfield Hydro	Hydro	Appalachian Power	14
Glen Ferris Hydro	Hydro	Brookfield Renewable Energy Partners	5
Summersville Hydro	Hydro	Gauley River Power Partners	80
Hannibal Dam	Hydro	New Martinsville (Municipality)	37
Ceredo Station	Natural Gas	Appalachian Power	450
Big Sandy Peaker	Natural Gas	Big Sandy Peaker LLC	342
Pleasants Energy Peaker	Natural Gas	Dominion Pleasants Inc.	300

Figure 8: West Virginia Power Producers Subject to the 111(d) Rule



C. Delivery of Electricity to West Virginia Customers

Utility companies can be investor-owned or consumer-owned. Investor-owned utilities are private companies, subject to state regulation and financed by a combination of shareholder equity and bondholder debt. These are usually large, multi-state companies, often organized as holding companies with multiple subsidiaries, or affiliates controlled by a common parent company. The investor-owned companies in West Virginia either own coal-fired power generating stations, themselves, or are subsidiaries or affiliates of companies that own generating stations. Consumer-owned utilities include city-owned or municipal utilities, which are governed by the local city council or another elected commission, and cooperatives, which are private nonprofit entities governed by a board elected by the customers of the utility.[57]

West Virginia's electric industry is comprised of the following private and municipal utilities which provide power to customers in the state and are regulated by the WV PSC:[58]

57 RAP. *Electricity Regulation in the US: A Guide*, March 2011, p. 10.
58 West Virginia Public Service Commission. http://www.psc.state.wv.us/utilities/

Investor Owned Utilities:

- Appalachian Power Company (APCo) – serves Boone, Cabell, Clay, Fayette, Greenbrier, Jackson, Kanawha, Lincoln, Logan, Mason, McDowell, Mercer, Mingo, Monroe, Nicholas, Putnam, Raleigh, Roane, Summers, Wayne, and Wyoming Counties
- Monongahela Power Company – serves Barbour, Braxton, Brooke, Calhoun, Clay, Doddridge, Gilmer, Grant, Greenbrier, Hancock, Harrison, Jackson, Lewis, Marion, Mineral, Monongalia, Nicholas, Pendleton, Pleasants, Pocahontas, Preston, Randolph, Ritchie, Roane, Taylor, Tucker, Tyler, Upshur, Webster, Wetzel, Wirt, and Wood Counties
- The Potomac Edison Company – serves Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral, Morgan Counties
- West Virginia Power, a Division of Monongahela Power – serves Greenbrier, Morgan, Pocahontas and Summers Counties
- Wheeling Power Company – serves Marshall and Ohio Counties

Consumer Owned Utilities:

- Black Diamond Power Company – serves Clay, Raleigh and Wyoming Counties
- City of New Martinsville – serves Wetzel County
- City of Philippi – serves Barbour County
- Craig-Botetourt Electric Cooperative – serves Monroe County
- Harrison Rural Electrification Association, Inc. – serves Barbour, Doddridge, Harrison, Lewis, Marion, Taylor and Upshur Counties

D. Overview of the Electricity Market as it relates to West Virginia EGUs

The state's power generators have historically produced about two and a half times the state's power needs. The power produced in West Virginia is sold on the grid through regional power markets. Decisions the state makes on a state plan may affect our power producers' position in the markets in which they compete. Because a summary describing the power markets in which West Virginia units compete may be helpful to decision makers in understanding the impact of state plan decisions, the WVDEP provides it here.

PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. PJM acts as a neutral, independent party, operating both a region-wide high-voltage transmission system to ensure service reliability and a competitive wholesale market in which capacity and energy is purchased and sold to meet the needs of the load serving entities (LSEs) within the PJM region.

The PJM energy markets are the markets that are operated to commit generation resources a day-ahead of operation (Day-ahead Market) and actually dispatch generation resources in real-time system operation (Real-time Market) to serve load and maintain operational reliability. All non-industrial electric generating facilities located in West Virginia are participants in the PJM market. The other principal market PJM operates is its PJM Reliability Pricing Model (RPM) Capacity Market. This market provides a revenue stream to power generators to ensure there is sufficient generation capacity and demand resources available to serve the expected peak load each year while accounting for variations in weather, load forecast error, and generation outages.

There are two categories of LSE PJM member companies with regard to capacity obligations. The first category comprises the companies that sell all their available capacity into the PJM RPM market and then buy back from the market all of their customers' capacity requirements. The LSE companies that rely on the PJM capacity market are sometimes referred to as RPM companies. Under this model, PJM determines how much capacity each LSE requires to meet its customers' peak load requirement, plus a capacity reserve. Even if an RPM company owns capacity, it effectively buys its capacity requirements from the PJM RPM market. The following table identifies capacity owned by West Virginia LSEs that participate in the RPM market.

Table 7: Electricity Capacity Owned by West Virginia Load Serving Entities that Participate in the Reliability Pricing Model Capacity Market

Generating Plant	Fuel Source	Ownership	Nameplate Capacity in MW
Grant Town Station *	Coal - Waste	American Bituminous Power	96
Fort Martin Station	Coal - Bituminous	Monongahela Power	1,152
Harrison Station	Coal - Bituminous	Monongahela Power	2,052
Morgantown Energy *	Coal - Waste	Morgantown Energy Associates	69
Hannibal Dam *	Hydro	New Martinsville (Municipality)	19

* Power sold to Monongahela Power Company under a bilateral contract.

In addition to capacity owned by West Virginia LSEs, there are other generation facilities in West Virginia that participate in the PJM RPM market.

Table 8: Other Generation Facilities in West Virginia that Participate in the PJM Reliability Pricing Model Capacity Market

Generating Plant	Fuel Source	Ownership	Nameplate Capacity in MW
Laurel Mountain	Wind	AES Wind Generation	98
Dam 4	Hydro	Allegheny Energy Supply	2
Dam 5	Hydro	Allegheny Energy Supply	1
Millville	Hydro	Allegheny Energy Supply	3
Belleville Dam	Hydro	American Municipal Power –Ohio	42
Willow Island Dam	Hydro	American Municipal Power - Ohio	44
Big Sandy Peaker	Natural Gas	Big Sandy Peaker LLC	342
Glen Ferris Hydro	Hydro	Brookfield Renewable Energy Partners	5
Pleasants Energy Peaker	Natural Gas	Dominion Pleasants Inc.	300
Mt. Storm Station	Coal - Bituminous	Dominion Resources	1,681
Mountaineer Wind Energy	Wind	Florida Power and Light	66
Longview Station	Coal - Bituminous	Longview Power LLC	780
Mount Storm Wind	Wind	Nedpower Mount Storm	264
Pleasants Station	Coal - Bituminous	Allegheny Energy Supply	1,368

The second category of companies in the PJM region for capacity purposes are the Fixed Resource Requirement (FRR) companies. Unlike an RPM Company, a FRR Company does not sell all its capacity into the market and buy back the capacity requirements of its customers. Rather, these companies self-supply and are obligated to either own physical generating capacity assets or have owned capacity assets plus sufficient additional capacity under bilateral contract to meet their customer's peak load, plus an adequate reserve margin. To the extent that an FRR Company has capacity in excess of its peak load requirement, it may be able to sell some of its excess capacity into the RPM market. The following table identifies those generating plants located in West Virginia that participate in the capacity market as FRR resources.

Table 9: Generating Plants Located in West Virginia that Participate in the Capacity Market as Fixed Resource Requirement Companies

Generating Plant	Fuel Source	Ownership	Capacity Rating in MW
Amos Station	Coal - Bituminous	Appalachian Power	2,932
Mountaineer Station	Coal - Bituminous	Appalachian Power	1,300
Mitchell Station	Coal - Bituminous	50% Wheeling Power 50% Kentucky Power	816 816
Ceredo Station	Natural Gas	Appalachian Power	450
Beech Ridge *	Wind	Beech Ridge Energy	100
Summersville Hydro *	Hydro	Gauley River Power Partners	80
Marmet Hydro	Hydro	Appalachian Power	14
London Hydro	Hydro	Appalachian Power	14
Winfield Hydro	Hydro	Appalachian Power	15

* Power sold to Appalachian Power Company under a bilateral contract

Both RPM and FRR companies sell their available energy into the PJM regional energy market on a day-ahead, hour by hour, basis throughout the day. Prices in this market are based on generator sell offers and PJM projections of day-ahead hourly energy requirements. PJM accepts sell offers starting with the blocks of lowest priced power offered into the market and then stacking the next higher priced blocks until it has accepted enough energy to meet expected day-ahead hourly energy requirements. PJM's real-time energy market operates to fine tune energy needs as load varies from the projections that had been made on a day-ahead basis, and generation availability are affected by unexpected outages, or re-dispatch of plants due to transmission outages or overloads.

b. Comprehensive Analysis of 11 Criteria Identified in HB2004

Before discussing each of the eleven factors identified in W.Va. Code § 22-5-20(g), the WVDEP provides a brief discussion of the process it used to perform the analysis, some background on modeling and makes general observations concerning the feasibility study, comprehensive analysis and report. This information should be useful to an understanding of the discussion of the eleven factors that follows.

1. WVDEP's Process for the Analysis

On August 3, 2015, the President announced the finalization of the EPA 111(d) rule. Even though this rule was not formally finalized until October 23, 2015, WVDEP immediately began to gather information for the HB2004 feasibility study and comprehensive analysis. Much of the information needed resides with the state's power generators. A request for information pertinent to the requirements of HB2004 was drafted and sent to the six owners of the electric generating facilities on August 18, 2015. After several subsequent conversations between the WVDEP and the power companies, the WVDEP hosted a meeting of the state's power generators on September 14, 2015 to layout the scope of the study and respond to questions about the study and information request. Representatives of the West Virginia Division of Energy and WV PSC staff also attended. At this meeting, it was agreed that responses to the WVDEP's request would be submitted two weeks after publication of the final §111(d) rule in the Federal Register. Follow-up meetings have been held with individual power companies.

To analyze economic issues, the WVDEP contracted with CBER. CBER in turn subcontracted with EVA for analysis of power markets. CBER has backgrounds in regional economic development, labor economics, and energy and resource economics. EVA is an energy consulting firm in Arlington, Virginia which focuses on economic, financial and risk analysis for the electric power, coal, natural gas, petroleum, and renewable, and emissions sectors. EVA provided analysis on the energy market impacts of potential compliance, including levels of electricity generation, wholesale electricity prices, natural gas and carbon prices. CBER took EVA's energy market projections and used them to model the resulting economic impact of four different state plan scenarios.[59]

In early October, 2015, the WVDEP identified 26 entities from government, industry, labor, environmental and public interest groups that might be stakeholders or that otherwise might have information that would be useful in the feasibility study, comprehensive analysis and eventual state plan development. Input was solicited from each of these entities in the first week of October.

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[59] There are a multiplicity of potential compliance scenarios. Rather than attempt to model all of them, which would involve considerable expense and require some degree of pure speculation as to the actions of others, the WVDEP chose to model four major scenarios that are believed to represent the outward bounds of potential impact of state plan approaches.

Table 10: Organizations from which WVDEP Solicited Information, October 2015

<u>Power Sector Management</u> NERC - North American Electric Reliability Corporation PJM Interconnection ReliabilityFirst	<u>Trade Groups</u> IOGAWV WV Chamber of Commerce WV Coal Association WV Manufacturers Association WVONGA
<u>Government</u> FERC - Federal Energy Regulatory Commission U.S. Department of Energy - National Energy Technology Laboratory WV Attorney General WV Department of Commerce WV Department of Revenue WV Department of Health and Human Resources Bureau for Public Health WV Division of Energy WV PSC Utilities Division WV PSC Consumer Advocate Division	<u>Environmental and Public Interest Groups</u> Ohio Valley Environmental Coalition People Concerned About Chemical Safety WV Chapter, Sierra Club WV Citizen Action Group WV Council of Churches WV Environmental Coalition WV Highlands Conservancy WVU College of Law - Center for Energy & Sustainable Development <u>Labor</u> UMWA - United Mine Workers of America

In mid-October, 2015, WVDEP reached out to the general public through several means and invited them to provide their input. Responses from stakeholders and the public were requested by December 31, 2015, although the WVDEP has accepted responses and supplemental information received since then. A page was also established on the WVDEP website to provide information on the Clean Power Plan the feasibility study: http://www.dep.wv.gov/pio/Pages/Clean-Power-Plan.aspx

A team of seven WVDEP staff members have been dedicated to the feasibility study effort. The WVDEP team has reviewed the information received from a wide variety of interests and points of view. It has also engaged in some independent research. The analyses within this report are based on the most recent and relevant information available.

2. Electric Sector and Economic Modeling

The comprehensive analysis presented here relies heavily on modeling of the electric sector and regional economy. Analyses of the impact of the 111(d) rule being conducted by others also relies heavily on modeling results. The results of different modeling efforts do not readily allow for an "apples-to-apples" comparison of seemingly similar results. This section provides an overview of the types of electric sector models that are available in order to provide some insight into the types of models chosen and the analysis performed by CBER, EVA and others.

Basically, models are mathematical representations of systems, which provide estimates for key elements of interest. For example, given the appropriate inputs, meteorological models may predict near term temperatures, estimate precipitation and forecast the development of weather fronts. Likewise, models exist to provide insight into the behavior of the electric sector under given input assumptions and various system constraints. Electric sector models may be broadly classified into five groups:[60]

Production Cost Models. Tools that determine the optimal output of the EGUs over a given timeframe (one day, one week, one month, one year, etc.) for a given time resolution (sub-hourly to hourly). These models generally include a high level of detail on the unit commitment and economic dispatch of EGUs, as well as on their physical operating limitations. They are not, however, designed to determine the optimal addition of new EGUs to meet future capacity requirements or the retirement of noneconomic EGUs. E.g., PROSYM, PLEXOS, AURORAxmp, and GE-MAPS

Utility-Scale Capacity Expansion and Dispatch Models. Tools that determine the optimal generation capacity and/or transmission network expansion in order to meet an expected future demand level and comply with a set of regional/state specifications (reliability requirements, renewable portfolio standards, CO_2 emissions limits, etc.). These models operate at the resolution of individual EGUs. E.g., System Optimizer, Strategist, PLEXOS-LT, AURORAxmp, RPMI

National-Scale Capacity Expansion and Dispatch Models. Tools that determine the optimal generation capacity and/or transmission network expansion in order to meet an expected future demand level at a national (or large regional) scale. As a result of the higher dimensionality, these models typically exhibit a lower resolution than utility-scale models (e.g., demand represented in "blocks" as opposed to using an hourly resolution; aggregation of similar EGUs into model plants). E.g., IPM. ReEDS, NEMS, HAIKU, POM

Multi-Sector Models. Tools that explore the interaction between different sectors of the energy system, as well as macroeconomic factors, using either a general equilibrium or partial equilibrium approach. These models typically include transportation, industry, commercial, and residential sectors, in addition to electricity production. These models generally operate at an aggregate level of model plants or technology types, similar to the national-scale capacity expansion models. E.g., MARKAL, NE-MARKAL, NEMS, EPPA, NewERA

Non-Optimization Approaches. Tools that develop approximate predictions of future production and/or investment decisions, or provide detailed bookkeeping of user-based decisions. These tools may make decisions based on expert judgement, heuristic rules, scenario analysis, or statistical analysis). These tools often rely on external projections of supply, demand, and other economic conditions; and they do not explicitly optimize the

[60] Fisher, Sisternes et al. February 1, 2016, "A Guide to Clean Power Plan Modeling Tools, Analytical Approaches for State Plan CO_2 Performance Projections". Note, some models may fall into multiple groups.

operation of a power system or simulate economic equilibrium conditions. E.g., ERTAC, AVERT, CP3T, CPP Planning Tool, CPP Evaluation Model, SUPR, STEER, LEAP

The figure below table below provides a comparison of the trade-offs among the various electric sector models. A particular model may fall into multiple classifications depending on initial set-up or "mode" that it is run in.

Figure 9: Summary of Modeling for Five Classifications

		Features represented			
		Generation	Transmission	Demand and Renewable Resources	Geographic scope
Production Cost Models *e.g., PROSYM (ABB), PLEXOS (Energy Exemplar), PCI Gentrader, AURORAxmp (EPIS), and GE-MAPS*		Output decision at the individual EGU level	Major transmission lines and nodes represented	Chronological, hourly resolution or less	Regional to interconnect
Utility-Scale Capacity Expansion Models *e.g., System Optimizer (ABB), Strategist (ABB), PLEXOS-LT, AURORAxmp, RPMI (NREL)*		Investment and dispatch decisions at the individual EGU level	Discrete/selected transmission lines represented	Non-chronological, Hourly (typical week) or coarser resolution	Utility, state or discrete region
National-Scale Capacity Expansion Models *e.g., IPM (ICF), ReEDS (NREL), NEMS EMM (EIA), HAIKU (RFF), POM (Navigant)*		Aggregated capacity buildout by technologies (generally does not incorporate individual EGU granularity)	Representation of transmission capacity limits between major zones	Non-chronological, demand in multi-hour blocks Poor representation of extreme events	Interconnect to national
Multi-Sector Models *e.g., MARKAL (IEA ETSAP), NE-MARKAL (NESCAUM), NEMS (EIA), EPPA (MIT), NewERA (NERA)*	*General equilibrium*	Model plants representing individual technologies.	No representation of transmission	Large demand blocks	Regional to national
	Partial equilibrium	Model plants representing individual technologies.	No representation of transmission	Demand blocks/hourly resolution	Varies
Non-Optimization Approaches *e.g., EGU Growth Tool (ERTAC), AVERT (EPA), CP3T (Synapse), CPP Planning Tool (MJ Bradley), CPP Evaluation Model (Energy Strategies)* *SUPR (ACEEE), STEER (AEEI), LEAP (SEI)*	*Screening curves-based heuristics*	Model plants representing individual technologies.	No representation of transmission	Demand blocks/hourly resolution	Varies
	Net present value (NPV) calculations [13]	EGUs are price takers Simulation of the cash-flows of an individual EGU	Representation of transmission congestion through historical locational marginal prices	Hourly resolution	Varies
	Merit order-based heuristics	Variable cost-based dispatch of the EGUs in the system	No representation of transmission	Hourly resolution	Varies

Note: Many models listed here by name can span more than one classification, depending on the features selected in a particular model run or the "mode" the model is run in. For ease of exposition, the model has been classified using its most commonly designated category. Therefore, the listed features do not necessarily perfectly apply to each individual model in that is provided as an example for a given model classification. The list of specific models show here is representative and non-exhaustive.

Source: Fisher, Sisternes et al. February 1, 2016, "A Guide to Clean Power Plan Modeling Tools, Analytical Approaches for State Plan CO_2 Performance Projections," p. 7 .

There are nearly always tradeoffs among the various available models, the level of detail needed and the resources required to gather the inputs and run the models. The non-optimization models may be attractive as "screening level tools" for their ease of use and fairly low computational requirements. However, it has been noted, "One risk in using these tools alone is that states may substantially over- or underestimate compliance requirements and costs. Therefore, in many cases it may be in a state's best interest to ultimately use more detailed, industry standard models, populated with accurate data, to ensure that a compliance plan is cost-effective, equitable, and achievable."[61]

Different models have different primary focuses and overlapping functionality. They may yield different results, even when applied with good intent and due diligence. All models have limitations and have inherent simplifying assumptions. Further, in simulating real world conditions there are nearly always significant uncertainties in key input assumptions. Therefore, model results should be interpreted with care. Actual outcomes may be quite different than predicted, even when adequate care has been taken to develop reasonable inputs and the model(s) have been properly run.

Many of the above models have the capability to calculate certain economic information of interest such as natural gas prices ($/mcf) and carbon dioxide allowance prices ($/ton). For this report, it was necessary to further explore downstream economic impacts. Hence, the modeling conducted in support of this report was conducted by EVA and CBER in two phases[62]:

1. The impact of compliance on the performance of West Virginia-based EGUs in the wholesale electricity market

2. The impact of any changes to plant output and associated changes in electricity supply, including cost of supply, on the economy of West Virginia

The first phase was performed by EVA which has extensive experience using AURORAxmp. It is capable of simulating the electric sector on a national scale while retaining output data at the regional and state scale. The modeling produces estimates of total generation (GWh) for West Virginia EGUs and potential carbon prices (for allowances or ERCs depending on mass- or rate-based compliance), as well as wholesale electricity prices (PJM West) and natural gas prices (Henry Hub).

The second phase was performed by CBER using outputs of AURORAxmp to determine key input assumptions for economy-wide model developed by Regional Economic Models Incorporated (REMI), PI+, to estimate the economic impact to the state of West Virginia of the changes to electricity generation. REMI PI+ is a proprietary, dynamic model widely used in the assessment of policy and economic changes to capture potential changes in employment, earnings, and output. More details of the modeling are contained in the full CBER economic study contained in the appendix.

61 Ibid

62 Shand, J., Risch, C., et al. "EPA's Carbon Dioxide Rule for Existing Power Plants: Economic Impact Analysis of Potential State Plan Alternatives for West Virginia," (CBER Report) March 2016, p. 29.

3. Analysis of the Eleven Factors Listed in W.Va. Code § 22-5-20(g)

Among other things, W.Va. Code § 22-5-20(c)(1) directs the WVDEP to report to the Legislature regarding the feasibility of the state's compliance with EPA's 111(d) rule and to include a comprehensive analysis of this rule's effect on the state, including the need for changes in state law and the eleven factors referenced in W.Va. Code § 22-5-20(g). The analysis provided below assumes that the changes in state law recommended above have been made and the full range of compliance options contemplated by the EPA rule are available to West Virginia.

The economic modeling and analysis CBER performed examined four possible compliance approaches: the rate-based approach, both with instate-only trading and with national trading, and the mass-based approach, both with instate-only trading and with national trading. These four analyses do not represent every possible compliance scenario, but they do fairly represent the outer boundaries of the range of impacts from potential state plan decisions. The modeling of each of the two national trading scenarios presumes that all states engage in the same national trading scheme. In reality, all states are unlikely to choose the same compliance pathway. Therefore, what happens in reality is unlikely to exactly mirror the modeled results.[63] The modeling is nonetheless useful in projecting the direction and magnitude of impacts, thereby informing decisions on state plan development.

Based on the CBER – EVA comparison of these four scenarios to modeling of the business-as-usual (BAU) approach, it appears that West Virginia could comply with the 111(d) rule with the least possible disruption to the state's economy by adopting a mass-based compliance plan and participating in a national, or otherwise similarly robust, market for trading allowances. Their modeling also shows that a rate-based plan with trading of ERCs in a robust market might also be feasible with relatively small disruptions. The CBER – EVA modeling for both the mass-based and rate-based scenarios with national trading project that West Virginia electric generation will actually exceed 2014 levels for most of the time from initial implementation of the 111(d) rule in 2022, through 2030 and beyond.

Although it is stated above, in a comprehensive analysis of section 111(d) impacts, it bears repeating that decisions the WVDEP and the Legislature can make on a state plan have limited impact on the state's coal production. Only 15% of the coal produced in the state is consumed in the state's electric generating units. Accordingly, the effect on the West Virginia coal industry from decisions the state makes on a 111(d) compliance approach is limited to this portion of our coal production. West Virginia's 111(d) decisions cannot impact the 85% of our coal production that leaves the state. The effect CO_2 regulation will have on the 55% of West

[63] For modeling to better reflect reality, projections as to the types of compliance plans individual states might choose would have to made and included in the model. However, In light of the additional time the Supreme Court's stay provides, states that are still considering 111(d) options are carefully considering the best compliance approach, should development of a state plan still be required after litigation is complete. Under these circumstances, any attempt to project compliance decisions other states might make for use in a model would require pure speculation. Because it would be based on speculation, any effort to more precisely model the consequences of EPA's 111(d) regulation would be unlikely to produce results that have any utility.

Virginia's coal production that is exported to other states will be determined by decisions other states make on their 111(d) state plans. The remaining 30% of the state's coal production that is exported to other countries may be affected by CO_2 reduction efforts those other countries make.

A last general observation the WVDEP will make before examining the eleven factors identified in W.Va. Code § 22-5-20(g) is that the discussion of consumer impacts and market based considerations and part of its discussion on the impacts from hypothetical power plant closures (items 1, 4 and 9, respectively, of the eleven factors WVDEP must examine) are based primarily on the work CBER and its contractor, EVA, performed. CBER's full report of its efforts is included with this report in the appendix. The WVDEP urges readers to consult the CBER report for a more complete discussion of these and other economic impacts.

Comprehensive Analysis Factor 1: Consumer Impacts, Including Any Disproportionate Impacts of Energy Price Increases on Lower Income Populations

If the EPA's rule goes into effect, generators of the electricity used in West Virginia will need to acquire a sufficient number of allowances or ERCs to enable them to comply. The cost of these allowances/ERCs will determine which efficiency improvements that might reduce emissions at individual electric generating units are cost effective to make. The cost of allowances/ERCs and any efficiency improvements needed to comply will be passed on to consumers.

Under each of the four state plan pathways modeled, CBER and EVA projected compliance costs arising from West Virginia EGU's acquisition of allowances/ERCs. They also projected the resultant increases in electricity costs for West Virginia consumers. The assumptions they made in this analysis were: (1) that the state distributes allowances to EGU owners, free of charge, in the mass-based case with national trading and the EGU owners purchase additional allowances on the market; and, (2) in the mass-based instate-only case, compliance is attained by reducing generation to the level allowed by the number of allowances the state has to distribute. The following text and tables show projected costs of compliance that are passed on to West Virginia consumers under different compliance scenarios. It is repeated from pages 41 – 42 of CBER's report (footnotes not included).[64] See the Appendix for the complete CBER report.

> Table [11] displays the estimated allowance prices and total values under a mass-based national trading scenario. Allowance prices, and associated total cost to EGUs and West Virginia consumers, rise throughout the compliance period as the emissions target becomes more stringent. Total allowance value is the value of allowances the affected EGUs must purchase, and can afford to purchase and still

[64] Here, and elsewhere in this report where portions of the CBER Report are quoted extensively, the WVDEP has substituted its own Table and Figure numbers for those used in the CBER Report in both the titles of these tables and figures and in references to them in the accompanying text. This is done so the quotation of sections of the CBER Report herein does not cause two different tables or figures to be assigned the same number. Where WVDEP has done this, the substituted WVDEP numbers appear in brackets. Beneath each of the tables or figures where WVDEP has done this, WVDEP identifies the source table or figure from the CBER Report by the number assigned to it in the CBER report.

remain competitive electricity suppliers. This value increases from $112 million in 2022 to $324 million in 2030. The estimated cost to West Virginia consumers from carbon allowances, as determined by the share of electricity generated that is consumed within the state, is initially $47 million and increases to $138 million under this scenario. The remaining value is assigned to wholesale generation or to retail customers in other states. As mentioned previously, if fewer states participate in mass-based trading then the number of available allowances is likely to be lower, and the allowance price higher which would result in higher cost of allowances.

Table 11: Projected CO_2 Costs and Allowances Needed Under Mass-Based National Trading

	2022	2023	2024	2025	2026	2027	2028	2029	2030
U.S. Allowance Price ($2015/short ton)	$4.35	$4.76	$5.44	$5.65	$6.21	$6.89	$7.46	$8.24	$9.43
# Allowances Needed by WV EGUs (million)	25.7	25.3	25.8	32.1	31.8	31.0	34.0	33.4	34.4
Total Allowance Cost/Value ($2015M)	$112	$121	$140	$181	$197	$214	$254	$275	$324
Cost to WV Consumers ($2015M)	$47	$51	$59	$76	$83	$90	$107	$116	$138

Source: Allowance prices are EVA projections. Allowances needed are CBER calculations.

[Reproduced from CBER Report Table 19]

Due to the nature of coal-fired generation, ERCs must be purchased in both rate scenarios, although the levels are fewer in the no-trading case because generation is much lower. Tables [12] and [13] display the estimated ERC prices resulting from the rate-based scenarios with and without national trading. In a rate-based scenario with national trading, West Virginia-based EGUs remain competitive in the wholesale market and maintain fairly high levels of generation with emission rates (lb/MWh) that exceed the standard. ERC prices, and associated total cost to EGUs and West Virginia consumers, rise throughout the compliance period as the emissions target becomes more stringent.

Table 12: Projected CO_2 Costs and ERCs Needed for West Virginia under Rate-Based National Trading

	2022	2023	2024	2025	2026	2027	2028	2029	2030
U.S. ERC Price ($2015/MWh)	$11.41	$12.52	$13.72	$15.02	$16.47	$18.22	$19.64	$21.72	$24.68
# ERCs Needed by WV EGUs (million)	19.8	19.6	19.2	30.8	30.7	30.3	39.3	38.3	43.6
Total ERC Cost/Value ($2015M)	$226	$246	$264	$462	$506	$553	$773	$831	$1,075
Cost to WV Consumers ($2015M)	$78	$82	$84	$163	$175	$187	$271	$285	$377

Source: ERC prices are EVA projections. ERCs needed are CBER calculations.

[Reproduced from CBER Report Table 20]

Under the rate scenario without trading, ERC sales are confined to state borders. This restriction causes ERC prices to be much higher as opportunities for trade are very limited. This scenario reduces the competitive position of West Virginia-based EGUs, causing several units to close and total generation to be greatly reduced to a level that is less than in-state demand. This reduction causes the amount of ERCs needed to be much lower than the rate scenario with trading and thus results in lower CO_2 costs to consumers. **However, evaluation of this scenario based solely on CO_2 costs is not complete because the additional cost complexities of procuring replacement energy and capacity required to meet in-state demand under this scenario are not included. As such, there may be additional costs as electricity must be imported or new facilities constructed to satisfy in-state demand.**

Table 13: Projected ERC Values and ERCs Needed Under a Rate Scenario Without Trading

	2022	2023	2024	2025	2026	2027	2028	2029	2030
WV Demand[92] minus Total Generation (GWh)	(4,427)	(11,979)	(17,467)	(19,874)	(20,015)	(21,473)	(21,951)	(21,438)	(22,993)
ERC Price in WV ($2015/MWh)	$102.62	$94.67	$86.50	$84.58	$80.70	$69.64	$68.85	$65.15	$65.58
# ERCs Needed (million)	7.3	5.6	4.4	6.2	6.2	5.7	7.4	7.6	8.2
Total ERC Cost/ Value ($2015M)	$750	$531	$379	$522	$499	$397	$507	$498	$536
Cost to WV Consumers ($2015M)	$162	$62	$(7)	$41	$22	$(11)	$21	$13	$14

Source: ERC prices are EVA projections. ERCs needed are CBER calculations.

[Reproduced from CBER Report Table 21]

The following discussion of impacts on retail electricity prices and illustrative tables are repeated from pages 45-46 of the CBER report (footnotes not included).

Changes to retail electricity prices in West Virginia are estimated for the national trading scenarios based on EIA data for electricity sales revenue from sales to West Virginia-based customers in 2014 and the additional costs of acquiring allowances or ERCs. To estimate changes in electricity prices, the value of allowance or ERC costs accruing to West Virginia were added to 2014 electricity sales revenue. This comparison to 2014 is a simplifying assumption that real electricity prices are unchanged over the study period. Table [14] contains the results.

Estimated retail prices in West Virginia increase under both mass- and rate-based national trading scenarios, however the increase is more pronounced for rate-based. These price increases are estimated gross effects of the consumer-borne costs of CO_2 compared to current electricity expenditures. The net effects of future price changes are not evaluated, including any price increases from ordinary changes in the cost of delivering electricity. These prices changes are calculated outside the impact analysis and are not inputs to the REMI PI+ model.

Table 14: Estimated Changes to West Virginia Retail Electricity Prices Under National Trading

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Mass-Based	1.9%	2.0%	2.4%	3.1%	3.4%	3.6%	4.3%	4.7%	5.6%
Rate-Based	3.1%	3.3%	3.4%	6.6%	7.1%	7.5%	10.9%	11.5%	15.2%

Source: CBER calculations from REMI and EVA data

[Reproduced from CBER Table 22]

The following discussion and table, which are repeated from page 69 of the CBER report (footnotes not included) illustrate the disproportionate impact projected increases in retail electricity prices will have on low income households.

> To the extent that electricity rates may rise, lower income households may be relatively more impacted than higher income households. National data illustrate the significance of electricity spending to households of different income levels. As noted in Table [15], households in the lowest income quintile spend approximately 10 percent of their income before taxes on electricity. This share is more than twice that of households in the second quintile, and 10 times that of the wealthiest households. These data do not account for any tax credits or incentives households may receive to offset energy expenditures.

Table 15: U.S. Total Income and Electricity Spending by Quintile, 2014

Year	Lowest 20	Second 20	Third 20	Fourth 20	Highest 20
Total Income before taxes	$10,308	$27,028	$47,056	$76,988	$172,952
Electricity Expenditures	$ 1,066	$ 1,328	$ 1,483	$ 1,611	$ 1,932
Percent of Income before taxes spent on electricity	10.34%	4.91%	3.15%	2.09%	1.12%

Source: US Bureau of Labor Statistics, Consumer Expenditure Survey

[Reproduced from CBER Report Table 34]

Personal income in West Virginia is lower than the national average, while the state's poverty rate is higher than the national average.[65] West Virginia's overall per capita personal income is $36,132, with 18.4 percent of all ages in poverty. Compare this to the United States' overall per capita personal income of $46,049, with 15.8 percent of all ages in poverty. Based on

65 CBER Report, Table 52, pp. 97-98

higher levels of poverty and lower average income in West Virginia, increases to electricity rates will have a greater impact on a greater number of our citizens in comparison to the impact nationally.

Note: The potential impact on consumer's electric bills from premature closure of coal fired electric generating units is discussed below in connection with Comprehensive Analysis Factor 9 (impacts of plants closures), starting at page 70.

Comprehensive Analysis Factor 2: Nonair Quality Health and Environmental Impacts

Under section 111(a)(1) of the Clean Air Act, nonair quality health and environmental impacts are required to be taken into account in determining a BSER. The Clean Air Act assigns the responsibility for determining a BSER to EPA. In EPA's discussion of its BSER in the preamble to its final 111(d) rule, the only mention of non-air quality health and environmental impacts EPA makes is a simple assertion that there are no adverse impacts from its BSER.[66] However, as noted above in the summary of the 111(d) rule WVDEP has provided, EPA intends the BSER to have a transformative effect in the area of energy generation. The 111(d) rule is meant to bring about a transition from high carbon energy sources to low carbon sources. As a state with the second highest coal production in the nation, where over 95% of the electric power is generated from coal, West Virginia can expect to be one of the places that is most negatively impacted by this transition. People in the coal and power sectors who become unemployed as a result of this transition and are unable to find other work will also lose health insurance coverage their employers had provided. The potential increase in poverty carries with it the negative health impacts associated with poverty. These impacts are difficult to quantify but are nonetheless real. EPA fails to acknowledge these non-air quality health impacts in its BSER determination.

A non-air quality environmental impact EPA's BSER determination fails to consider is that the transition it seeks to effect may reduce or eliminate the environmental benefit derived from the power generators that use abandoned coal waste as their fuel source. Historic mining activity in West Virginia and surrounding states has left behind many abandoned coal waste piles that are sources of Acid Mine Drainage (AMD). As mentioned earlier, there are two EGUs in West Virginia – Morgantown Energy Associates and Grant Town – that utilize abandoned coal waste as their fuel source. Burning this coal waste provides an environmental benefit by eliminating existing sources of AMD. Also, the alkaline ash both of these facilities produce is used in remediation activities to further aid in elimination of AMD. In addition to the immediate benefit to the environment from elimination of AMD, the elimination of abandoned coal waste piles also reduces the amount of money that WVDEP's Office of Abandoned Mine Lands may otherwise have to spend on remediation of these piles. Choosing one of the state plan options that CBER – EVA models to most closely approximate business as usual – either of the options with national trading – may enable the state to avoid loss of the environmental benefit these two facilities provide. It may also enable the state to avoid the employment and associated impacts described in the paragraph preceding this one. If West Virginia chooses a state plan with instate

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[66] 80 Fed.Reg. 64709 (October 23, 2015).

trading, large employment losses and elimination of the environmental benefit these two facilities provide is much more likely.

Against these negative non-air quality and environmental impacts, the alleged positive impacts must be considered. EPA claims a variety of health benefits will accrue from reducing the impact of climate change which may be considered non-air quality impacts.[67] EPA has found that climate change may cause an increase in: heat-related mortality and morbidity; storm-related fatalities and injuries, and diseases; respiratory illness through exposure to aeroallergens; infectious diseases; stress-related disorders and other adverse effects associated with social disruption and migration from more frequent extreme weather; and, expanded ranges of vector-borne and tick-borne diseases.[68] EPA believes a reduction of the impact from climate change may result in a reduction of these negative effects.

A basic problem with EPA's forecasted benefits is that they cannot be derived from a single action, such as a decision on a West Virginia state plan, or even from adoption of EPA's 111(d) rule. Control of greenhouse gas emissions by one country has little effect on worldwide concentrations if other countries make no effort to control them. Consider that, in 2013, the United States produced 15% of the greenhouse gases emitted globally.[69] In the same year, electric generating units made up 30% of American greenhouse gas emissions[70] and West Virginia electric generating units made up 3.37% of American EGU emissions.[71] This means that, in 2013, West Virginia electric generating units comprised about 0.19% of the worldwide total emissions and American electric generating units comprised about 5.8% of worldwide total emissions. Even if all of America's CO_2 emissions from EGUs were somehow entirely eliminated (EPA's rule only seeks a 32% reduction), the difference in worldwide greenhouse gas emissions would be minimal. At the recent rate of increase in greenhouse gas emissions across the world (2 – 3% per year), increases elsewhere would more than make up for the absence of American EGU emissions in a very short time. If the goals of EPA and the UNFCCC to control the atmospheric concentration of greenhouse gases at some level they believe is necessary to prevent impacts of climate change is to be accomplished, it will take a worldwide effort directed at a much wider array of generators than just the U.S. EGU sector. The benefits EPA forecast will not result from its 111(d) rule or any decision West Virginia makes on a state plan.

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[67] The so-called, co-benefits from reductions of "criteria pollutants" that EPA has determined will come with reductions in CO_2 emissions cannot be deemed "non-air quality" impacts. These co-benefits arise from elimination of negative health impacts that result from breathing air that contains harmful concentrations of these criteria pollutants. These health benefits are derived directly from a projected improvement in air quality and, thus, are not "non-air quality health impacts" for purposes of this analysis.

In addition, the WVDEP believes EPA's claim of co-benefits to be somewhat dubious. Criteria pollutants are governed by national ambient air quality standards (NAAQS) which are required to be set at concentrations that protect public health with an adequate margin of safety. Clean Air Act § 109(b)(1). If NAAQS are set at appropriate concentrations and the programs for the control of the pollutants covered by a NAAQS are working, there should not be any "co-benefits" to public health to be derived from control of CO_2 emissions.

[68] Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, Technical Support Document, December 7, 2009, p. 82; 80 Fed.Reg. 64682 – 83.

[69] PBL Netherlands Environmental Assessment Agency, Trends in Global CO_2 Emissions, 2014, Report, p. 13, http://www.pbl.nl/en/publications/trends-in-global-co2-emissions-2014-report, Last visited April 14, 2016.

[70] EPA DRAFT Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Table 2-10. February 22, 2016. Last visited April 14, 2016.

[71] EIA Energy-Related Carbon Dioxide Emissions at the State Level, 2000-2013, Table 3, www.eia.gov/environment/emissions/state/analysis/ Last visited April 14, 2016.

Comprehensive Analysis Factor 3: Projected Energy Requirements

In this section, the WVDEP will address the ability of state power generation to meet the state's energy requirements. Issues related to the impact of the 111(d) rule on capacity and reliability, grid-wide, will be discussed below in connection with Comprehensive Analysis Factor 10: Reliability of the System.

West Virginia power producers generate nearly two and a half times more power than is consumed in the state, making West Virginia a net exporter of electricity. In 2014, West Virginia power plants generated 79.2 million MWh of electricity while in comparison, West Virginia customers consumed 32.7 million MWh. The remaining 46.5 million MWh was exported. The table below shows the total electrical generation from West Virginia in 2014.[72]

Table 16: West Virginia Electricity Generation and Capacity by Resource, 2014

Resource	MWh	Share MWh	MW Summer Capacity	Share MW
Coal	76,244,260	96.2%	13,538	87.7%
Hydro	713,154	0.9%	198	1.3%
Natural Gas	653,291	0.8%	1,071	6.9%
Other	162,125	0.2%	47	0.3%
Wind	1,451,383	1.8%	583	3.8%
Total	79,224,213	100.0%	15,437	100.0%

Source: EIA-923 and Inventory of Operating Generators (as of September 2015).

[Reproduced from CBER Report Table 5]

The projections EVA made for CBER predict somewhat of a decline in power generation by West Virginia's generating units through 2018, followed by a sharp increase from 2018 through 2020. See, Figure 10, below. According to CBER and EVA, this increase is due to the effect of projected rises in natural gas prices due to increased demand for gas from existing and new electric generating units and the export market that is expected to develop following the opening of several new LNG export facilities over the next three years. They expect higher gas prices, in turn, to make West Virginia's coal fired generation more competitive in regional electricity markets from 2018, forward, leading to higher output from West Virginia units.

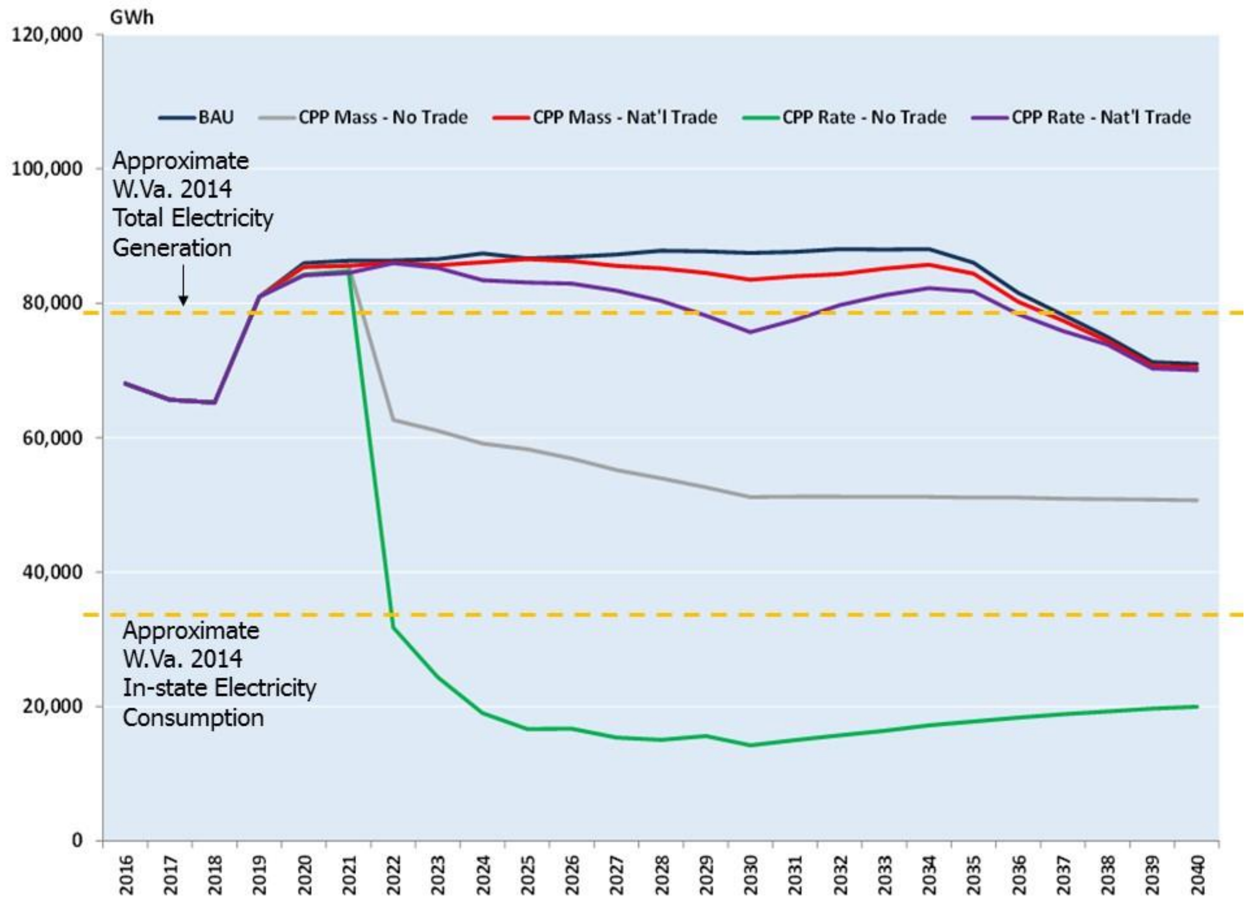
Following implementation of the 111(d) rule in 2022, the CBER – EVA projections for West Virginia power generation vary widely, based on which approach the state takes to compliance. Projections for both the mass-based and rate-based 111(d) compliance scenarios involving national trading have the state's level of generation above or near the 2014 level (79 million MW) through 2034, when generation is expected to decline. WVDEP understands the decline that CBER - EVA project to come after 2034 results from some West Virginia power units nearing the end of their useful lives at that time, rather than from the impact of this 111(d) rule. Unless there is an unforeseen spike in power demand or a cold spell of catastrophic

[72] Shand, J., Risch, C., et al. "EPA's Carbon Dioxide Rule for Existing Power Plants: Economic Impact Analysis of Potential State Plan Alternatives for West Virginia," March 2016 (CBER Report), p. 20.

proportions, West Virginia power production should more than meet West Virginia's energy needs under either of these projections involving national trading.

The CBER - EVA projection for the state plan scenario involving a mass-based plan with instate-only trading shows a fairly sharp decline in generation beginning with implementation of the 111(d) rule in 2022. Thereafter, generation levels off at a rate well above West Virginia's 2014 power usage (32 million MW) for the duration of the projections. Based on the CBER – EVA projections, state power generation under this scenario should be capable of meeting the state's energy requirements, although generation at a level well below historic levels may have many negative economic impacts. Under the CBER – EVA projection for the rate-based state plan scenario involving instate-only trading, state generation drops precipitously beginning with implementation of the 111(d) rule in 2022 and, thereafter, remains below the level of the state's 2014 power usage. If this state plan option is chosen and no new generation capacity is added, West Virginia power generation does not appear to be sufficient to meet the state's needs.

Figure 10: West Virginia Coal-Fired Power Generation Projections (GWh), BAU compared to Compliance Scenarios



Source: EVA Analysis
[Reproduced from CBER Report, Figure 5 – modified by WVDEP, to show West Virginia 2014 Electricity Generation and Consumption. CBER calls the instate-only trading options "No Trade."]

Comprehensive Analysis Factor 4: Market-Based Considerations in Achieving Performance Standards

Economic and market considerations are the primary reason WVDEP engaged CBER to assist in this comprehensive analysis. They are the main thrust of CBER's and EVA's modeling and CBER's report. Although WVDEP sets forth some important points below from CBER's analysis and from other sources, readers should consult CBER's report for a thorough exposition of these issues.

- Although West Virginia is one of the states that is most dependent on coal in its economy and as a source of power and can be expected to be among the most heavily impacted by the 111(d) rule, the state is not alone in feeling its impact. The cost of electricity and the economies of other states will also be impacted by the rule.

- West Virginia's remaining coal fired units are the second most efficient in the country, as a group.

- CBER – EVA's projections show the mass-based compliance approach with national trading is the least impactful one for West Virginia. It compares most favorably to business as usual (no EPA rule) and would have the least negative impact on state GDP, income, jobs, etc.

- According to CBER – EVA's projections, the rate-based approach with national trading also compares reasonably favorably with business as usual (no EPA rule).

- Based on these projections, West Virginia units could remain competitive in regional electricity markets past final implementation of the EPA rule in 2030 under either of the state plan approaches with national trading.

- One of the keys to these projections or any other modeling results concerning the impact of the EPA rule, in general, and on coal units, in particular, will be the price of natural gas.

- Gas units compete directly with coal units in regional energy markets. Overcapacity to produce gas as a result of the recent shale gas boom and other energy market conditions have combined to make gas very inexpensive, enabling it to displace coal's share in the generation of electricity in recent years.

- CBER – EVA predict gas prices will rise, enabling the remaining, efficient coal plants to be more competitive in energy markets. They base this prediction on: (1) increased demand for gas as a result of the opening of new LNG export terminals over the next three years, (2) demand from increased utilization of existing natural gas combined cycle (NGCC) units under the 111(d) rule, and (3) demand for gas from newly constructed NGCC units.

- Another key to these projections and any other modeling results concerning the impact of the EPA rule will be the robustness of the markets for trading allowances in the mass-based approach and ERCs in the rate-based approach.

- "National" trading in CBER – EVA,'s modeling includes 47 states. Alaska and Hawaii are not subject to the EPA rule. Vermont and the District of Columbia do not have any generating units affected by it.

- National trading is not necessarily required for a sufficiently robust market to support the continued competitiveness of West Virginia units in the electricity markets. WVDEP has seen modeling by some groups that actually project lower allowance prices in certain regional combinations of states than in a national trading scenario.

- The state plan choices made by other states are very significant. If West Virginia's choice of a state plan approach causes it to find itself with few other states as viable trading partners, the resultant impacts will more closely resemble the projections for the instate-only plans than the projections involving national trading.

- Coal unit retirements coming up in other states could free up allowances for the trading market, resulting in lower prices for allowances for remaining efficient coal units. If the states where such retirements occur elect to adopt rate-based plans, however, any "spare" allowances from the retirements will not be available for trading with units in states with mass based state plans.

- The northeastern and mid-Atlantic states that have been a part of the Regional Greenhouse Gas Initiative (RGGI) – Maryland, Delaware, New York, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire and Maine – may continue this regional compliance approach under the 111(d) rule and engage trading only among themselves. If most states form regional alliances like this, any state that is left out of a regional group may have a small market in which to trade, resulting in high compliance costs.

- States with new nuclear power generation coming online are believed to have an incentive to choose rate-based plans.

- The EM&V requirements that are a required part of a rate-based plan are so bureaucratically rigorous as to provide a disincentive to adoption of a rate-based plan. This EM&V would also be required in mass-based state plans which elect to adopt the Clean Energy Incentive Plan or Renewable Energy set-asides.

- Under any scenario in a rate-based plan, a coal fired unit will need ERCs to comply for its very first hour of operation. A significant number of ERCs will be needed for each and every hour of operation, thereafter. This is because the rate-based limit for coal, 1,305 lb CO_2/MWh, is well below the best rate a coal fired unit can attain. (Compare this rate to the aggregate rate for West Virginia units in the 2012 baseline year, 2,064 lb CO_2/MWh.)

- In contrast, in a mass-based plan where allowances might be distributed to West Virginia electric generating unit owners free of charge, these units will be able to produce a significant amount of electricity before they will need to incur compliance costs from the acquisition of additional allowances. Note: There is a more detailed discussion of choices to be made in allocation of allowances, starting at page 94.

- Costs of allowances or ERCs or other compliance costs will be passed on to customers.

- Any reductions in electric generation are likely to result in higher wholesale electricity costs that will, in turn, result in higher costs for customers.

- Should there be premature closure of a unit subject to regulation by the WV PSC, owners of those units will continue to recover the remaining undepreciated capital investment in that unit, plus a rate of return approved by the WV PSC, from ratepayers until the unit is fully depreciated. This means that electricity customers will continue to pay for units that no longer provide electricity, well after these units are prematurely closed. This is discussed in greater detail under Factor 9 below.

- Industrial, commercial and residential customers absorb different shares of costs, based on the share of variable generation revenue utilities receive from each customer class.

- Among residential electricity customers, lower income households spend a much higher proportion of household income for electricity costs. In West Virginia, a greater percentage of the population is low income than nationally. These consumers are particularly vulnerable to impacts from increased energy prices resulting from the EPA rule's impact.

In addition to modeling and analysis CBER and EVA performed for the WVDEP, Duke University's Nicholas Institute for Environmental Policy Solutions (Nicholas Institute) provided the WVDEP with some regional level results from modeling of the final EPA rule it conducted using its Dynamic Integrated Economy/Energy/ Emissions Model (DIEM). The Nicholas Institute had previously evaluated the proposed rule and offered preliminary analysis of the final 111(d) Rule. The component of the DIEM model used is a detailed electricity dispatch and capacity expansion model of U.S. wholesale electricity markets and represents intermediate- to long-term decisions about generation, capacity investments and dispatch. The Nicholas Institute's model and approach differ from CBER's and EVA's, however, on a broad scale, many similar conclusions can be made:

- Mass-based compliance scenarios with trading across the PJM region involve the lowest policy costs to the state for implementation of the EPA rule.

- Consistent with CBER – EVA's modeling, instate-only approaches have the highest costs to the state for implementation of the EPA rule.

- Mass-based compliance scenarios provide smaller reductions in coal generation across the region. However, the smallest reduction in coal generation modeled occurs in rate-based trading across the entire Eastern Interconnect.

As stated above, PJM Interconnection is performing modeling on the final 111(d) rule that will not be completed until a few months after this report is due. PJM believes that the directional magnitude of its modeling of the proposed 111(d) rule will prevail in its modeling of the final rule. Therefore, PJM's modeling of the proposed rule within its region provides some information that is useful in this analysis. As noted in the PJM analysis, PJM used the production cost simulation model known as PROMOD. This model simulates only the PJM energy markets under assumptions such as coal and gas prices, available generation resources, energy demand profiles, and transmission infrastructure in service. The model can incorporate variable costs for environmental compliance such as the price of sulfur dioxide, nitrogen oxide, and carbon dioxide allowances needed for compliance under the 111(d) rule. Notable points from this PJM analysis are:

- PJM projects lower wholesale electricity prices under regional rate based compliance than under regional mass-based compliance.

- More or less consistent with the CBER – EVA analysis, coal fired generation in West Virginia is 9 – 14% lower under rate-based compliance than in mass-based compliance.

- Compliance on a regional basis has the following advantages for West Virginia over instate-only compliance:

    - Lower overall wholesale energy prices for West Virginia;
    - Greater coal generation output;
    - Less overall coal capacity at risk for retirement in PJM; and
    - Lower overall compliance costs as measured by fuel and variable operation and maintenance costs.

- In the instate-only compliance scenario, West Virginia has the highest compliance costs in the PJM region.

- Increasing the amount of zero emitting renewable power, reducing demand for electricity through energy efficiency measures and increasing new natural gas combined cycle generation, which are not subject to the 111(d) rule:

    - Reduces the need to dispatch gas-fired power in place of coal fired power in order to comply;
    - Reduces demand for emission allowances, thereby reducing the cost of compliance; and,
    - Reduces the amount of coal fired generation at risk for retirement.

- Consistent with the CBER – EVA results, coal generation is much lower in West Virginia in an instate-only approach to compliance than it is in a regional compliance scenario.

- West Virginia clearly fares better in a regional compliance approach than in an instate –only approach.

- The judgment as to whether a rate-based or mass-based compliance scenario is better for West Virginia depends upon which course nearby and surrounding states take. The state would be well-served by coordination with these other states.

- Consistent with all other analyses, the price of natural gas makes a big difference in the outcome of the analysis.

Comprehensive Analysis Factor 5: Costs of Achieving Emission Reductions Due to Factors Such as Plant Age, Location or Basic Process Design

Comprehensive Analysis Factor 6: Physical Difficulties With or Any Apparent Inability to Feasibly Implement Certain Emission Reduction Measures

Comprehensive Analysis Factor 7: The Absolute Cost of Applying the Performance Standard to the Unit

Comprehensive Analysis Factors 5, 6 and 7 all require discussion of issues related to implementation of emissions reductions measures at individual electric generating units. Because of the interrelatedness of these issues, the WVDEP will discuss these three factors as a group. First, the WVDEP will provide an overview of CO_2 measures that may potentially be considered at individual electric generating units that will inform the discussion of factors 5, 6 and 7 that follows.

Heat Rate Improvements

In seeking CO_2 emissions reductions under the 111(d) rule, EPA's greater focus has been on sector-wide emissions reductions from fossil fuel-fired generators than on unit specific emissions reduction measures. The limits EPA established for coal and gas-fired units were based on three building blocks that, in combination, are intended to reduce CO_2 emissions. Of these, Building Blocks 2 and 3 reflect the sector-wide focus by aiming to force dispatch of the power necessary to supply the grid away from high CO_2 emitting coal units toward lower and zero CO_2 emitting generators of electricity. Building Block 1 was the only element EPA used in calculation of the limits which attempts to reduce CO_2 emissions from individual units.

In Building Block 1, EPA determined that 4.3% heat rate improvements were available from existing electric generation units. The problem with this conclusion is that these units have faced a steady stream of new environmental regulations over the years and one option for electric generating unit owners in response to these new regulations has always been to reduce emissions by improving the efficiency of these units in converting fuel into electric power. As new pollution control equipment has been installed to meet various requirements, including most recently the mercury rules, sources have had to consider any economically viable heat rate improvements. Not surprisingly, the owners of West Virginia EGUs have concurred that the potential for additional efficiency upgrades is very limited. The most efficiency improvement that can be expected at individual units is in the range of 1 to 2 percent.

Even these heat rate improvements may not be feasible if EPA's Building Blocks 2 and 3 are successful in directing generation away from coal fired units to low and zero emitting power producers. The 1 to 2 percent improvements that may be possible at individual EGUs are premised on the ability to operate at capacity. If coal units are forced to cycle in and out of full operating capacity, they are not nearly as efficient as when they are operating continuously at or near capacity. Building Blocks 2 and 3 are in tension with Building Block 1 because they aim to force coal units into cycling. If EPA is successful, any potential benefit from heat rate improvements made under Building Block 1 may be lost. Even if non-continuous operation does not make potential heat rate improvements unachievable, under the trading scheme envisioned by the 111(d) rule, analysis of the economic viability of making heat rate improvements will be judged against the cost of compliance by simply acquiring the ERCs or allowances necessary to comply. This will be discussed further below.

Fuel-Switching and Co-Firing[73]

Another approach to compliance through measures taken at individual units might involve alteration of existing coal units to burn natural gas instead or to co-fire with gas. The Integrated Resource Plan (IRP) Monongahela Power filed with the WV PSC in December, 2015 discusses the possibility of co-firing one or more of its coal fired units with natural gas. Monongahela Power's units are all located in proximity to the parts of the state that have experienced the shale gas boom that has exposed so much gas to the market that prices have fallen to near historic lows. According to the IRP, for every 10% of heating value the co-fired gas comprises, CO_2 emissions are reduced by 4%. The design under consideration would not require a large capital investment. It would allow up to 30% co-firing with gas, but Monongahela Power said it expected the actual range of its fuel mix to be closer to 80 – 90% coal. Monongahela Power anticipates that it would still need to purchase ERCs or allowances to comply, but fewer than if it remains 100% fueled by coal. An additional benefit foreseen from co-firing might be a reduction in certain pollutants other than CO_2. Although a reduction in the market for coal as a result of one or more units choosing to co-fire with gas would be disruptive to this already ailing industry, some suggest that co-firing may actually preserve some market for coal that might otherwise be lost upon implementation of the 111(d) rule, by reducing the compliance cost at the units that co-fire and by reducing the demand for allowances or ERCs, making them less expensive and compliance more affordable for units that continue to utilize coal for 100% of their fuel requirements.

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[73] W.Va. Code § 22-5-20(e)(3) prohibits WVDEP from imposing a standard of performance which requires fuel switching. However, this section leaves owners of electric generating units free to a make business decision to switch fuel sources as a compliance strategy, if they choose to do so.

Reducing Power Generation[74]

A simplistic approach to compliance in a mass-based plan might be to limit output in order to reduce the number of tons of CO_2 emitted. However, reduced operation is likely to radically change the economics of any unit's continued operation. Some units may no longer be viable. This approach would also be detrimental to both a unit's thermal efficiency and its ability to operate pollution control equipment optimally. Although operating at reduced generation may reduce the mass of CO_2 emitted, it would likely increase the CO_2 emissions rate. In addition, reduced operations are not in the interest the unit owners who have invested billions of dollars in capital in these facilities who wish to make a profit. Neither would it be in the interests of rate payers from whom the unit owners will recover the capital they have invested.

Carbon Capture and Storage (CCS)

While CCS is a unit-specific measure, it has not been proven to be commercially or economically feasible for existing electric generating units. There are no existing EGUs anywhere in the country that use CCS technology. Even the EPA acknowledges that it is not appropriate to require CCS at existing EGUs. However, as more CCS projects are developed around the world and as energy prices rise in a world constrained by carbon regulation, it is possible that a viable technology will be developed in the future. A number of obstacles to development of this technology will have to be resolved if this is to occur. Beyond the cost,[75] there is insufficient development of key legal issues, such as: the property rights that must be secured for utilization of the requisite pore space for CO_2 storage; the procedures for acquiring rights to pore space; long-term care liability; the process by which rights-of-way for CO_2 pipelines are acquired; and liability issues arising from the potential for induced seismicity from underground injection of fluids.[76]

Response to Factors 5, 6 and 7

All of these factors contemplate unit-specific measures to comply with the 111(d) rule. However, as this rule is written, the primary means of complying is more likely to be through acquisition of a sufficient number of ERCs or allowances in the broader marketplace to enable them to comply. The absolute cost of compliance is determined, in the first instance, by the number of allowances or ERCs needed and the unit prices for allowances or ERCs. The cost of this compliance currency in the market will determine whether it is economical to pursue heat rate improvements, to co-fire, to switch fuels or pursue other measures.

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74 W.Va. Code § 22-5-20(e)(3) prohibits WVDEP from imposing a standard of performance which limits economic utilization of a unit. This prohibition applies to WVDEP, but, again, does not prevent unit owners from reducing operations or closing units as a compliance strategy.

75 The flagship unit for CCS implementation, Southern Company's Kemper Plant, has been under construction since 2010 and its price tag now exceeds $6.6 Billion, $4.2 Billion over its original estimate. It is not expected to go into operation until at least the third quarter of 2016.

76 Petersen, M.D., Mueller, C.S., Moschetti, M.P., Hoover, S.M., Llenos, A.L., Ellsworth, W.L., Michael, A.J., Rubinstein, J.L., McGarr, A.F., and Rukstales, K.S., 2016, 2016 One-year seismic hazard forecast for the Central and Eastern United States from induced and natural earthquakes: U.S. Geological Survey Open-File Report 2016–1035, 52 p., http://dx.doi.org/10.3133/ofr20161035.

A first step in calculating compliance cost is to determine the value to be used for the costs of allowances and ERCs to use in the calculation. There will be a different cost of compliance for each of the four compliance scenarios CBER – EVA modeled. CBER and EVA projected prices for ERCs in both a national trading scenario and in a state only scenario. They also projected per-unit costs for allowances in the national trading scenario. In their analysis of the mass-based instate-only trading scenario, they assumed that allowances were given to EGU owners free of charge. So, while there is not a projected price for the allowances assumed to be given away, CBER-EVA calculated a shadow price of carbon that they believe represents the cost of compliance in this scenario.

The next step in this calculation requires values for electric generation and CO_2 emissions during the time period for which the calculation is performed. To provide some real world perspective instead of basing the calculation of compliance costs entirely on projections of future allowance prices, future ERC prices, future emissions and future generation, WVDEP decided to use information for actual emissions and generation for each West Virginia generating unit during EPA's baseline year of 2012 that remain in operation. The tables below show an illustrative calculation of what the absolute cost of compliance would be for the 2012 emissions and generation from each West Virginia unit if those emissions and that generation occurred in each of 2022, 2025, 2028 and 2030. These years are the first years in EPA's Step 1, Step 2, Step 3 and final compliance periods, respectively. Again, the values for allowances, shadow price of carbon and ERCs used in the calculations for each of these years are those projected by CBER – EVA.

Table 17: Absolute Cost of Compliance for 2012 Emissions & Generation in a Mass-based Plan with National Trading in 2022, 2025, 2028 and 2030 (*$ shown in millions except allowance unit cost*)

Company	Plant	Unit	2012 Generation^ (MWh net)	2012 CO_2 Emissions+ (tons)	2022 Allowance Cost* @ $4.35	2025 Allowance Cost* @ $5.65	2028 Allowance Cost* @ $7.46	2030 Allowance Cost* @ $9.43
AEP	John E. Amos	1	3,865,506	3,937,978	$17.1	$22.2	$29.4	$37.1
		2	3,592,334	3,586,863	$15.6	$20.3	$26.8	$33.8
		3	5,511,206	5,536,156	$24.1	$31.3	$41.3	$52.2
	Mitchell	1	4,055,621	4,166,944	$18.1	$23.5	$31.1	$39.3
		2	3,488,717	3,528,856	$15.4	$19.9	$26.3	$33.3
	Mountaineer	1	8,292,574	8,716,837	$37.9	$49.3	$65.0	$82.2
First Energy	Ft. Martin	1	3,694,783	3,686,690	$16.0	$20.8	$27.5	$34.8
		2	1,859,912	1,892,934	$8.2	$10.7	$14.1	$17.9
	Harrison	1	3,030,458	3,193,111	$13.9	$18.0	$23.8	$30.1
		2	3,203,134	3,157,607	$13.7	$17.8	$23.6	$29.8
		3	3,774,607	3,997,839	$17.4	$22.6	$29.8	$37.7
	Pleasants	1	4,113,316	4,149,695	$18.1	$23.4	$31.0	$39.1
		2	3,868,524	3,849,537	$16.7	$21.7	$28.7	$36.3
Dominion	Mt. Storm	1	3,471,365	3,668,691	$16.0	$20.7	$27.4	$34.6
		2	3,388,956	3,599,082	$15.7	$20.3	$26.8	$33.9
		3	1,673,384	1,763,648	$7.7	$10.0	$13.2	$16.6
GenPower	Longview	1	4,167,850	3,816,811	$16.6	$21.6	$28.5	$36.0
NRG	MEA	1A&1B	408,719	714,917	$3.1	$4.0	$5.3	$6.7
AmBit	Grant Town	1A&1B	660,511	1,000,609	$4.4	$5.7	$7.5	$9.4
Total			**66,121,477**	**67,964,805**	**$295.6**	**$384.0**	**$507.0**	**$640.9**

^U.S. DOE, EIA-923 Monthly Generating Unit Net Generation Time Series File, 2012 Final_Release, http://www.eia.gov/electricity/data/e

+ EPA Clean Air Markets Division, http://www.epa.gov/airmarkets

*Allowance Cost is the projected U.S. Allowance Price from CBER Report, Table 19.

Table 18: Absolute Cost of Compliance for 2012 Emissions & Generation in a Mass-based Plan without Trading in 2022, 2025, 2028 and 2030 *($ shown in Millions except allowance unit cost)*

Company	Plant	Unit	2012 Generation^ (MWh net)	2012 CO_2 Emissions+ (tons)	% 2012 Generation from Units Operating in 2016	2022 Allowance Cost* @ $10.70	2025 Allowance Cost* @ $12.68	2028 Allowance Cost* @ $15.24	2030 Allowance Cost* @ $16.69
					**Mass Limit (tons of CO_2)	66,557,024	56,762,771	53,352,666	51,325,342
					++Change in Generation from 2012 Levels (MWh)	-1,369,599	-10,898,215	-14,215,831	-16,188,171
AEP	John E. Amos	1	3,865,506	3,937,978	5.85%	$41.6	$42.1	$47.5	$50.1
		2	3,592,334	3,586,863	5.43%	$38.7	$39.1	$44.2	$46.5
		3	5,511,206	5,536,156	8.33%	$59.4	$60.0	$67.8	$71.4
	Mitchell	1	4,055,621	4,166,944	6.13%	$43.7	$44.1	$49.9	$52.5
		2	3,488,717	3,528,856	5.28%	$37.6	$38.0	$42.9	$45.2
	Mountaineer	1	8,292,574	8,716,837	12.54%	$89.3	$90.3	$102.0	$107.4
First Energy	Ft. Martin	1	3,694,783	3,686,690	5.59%	$39.8	$40.2	$45.4	$47.9
		2	1,859,912	1,892,934	2.81%	$20.0	$20.2	$22.9	$24.1
	Harrison	1	3,030,458	3,193,111	4.58%	$32.6	$33.0	$37.3	$39.3
		2	3,203,134	3,157,607	4.84%	$34.5	$34.9	$39.4	$41.5
		3	3,774,607	3,997,839	5.71%	$40.7	$41.1	$46.4	$48.9
	Pleasants	1	4,113,316	4,149,695	6.22%	$44.3	$44.8	$50.6	$53.3
		2	3,868,524	3,849,537	5.85%	$41.7	$42.1	$47.6	$50.1
Dominion	Mt. Storm	1	3,471,365	3,668,691	5.25%	$37.4	$37.8	$42.7	$45.0
		2	3,388,956	3,599,082	5.13%	$36.5	$36.9	$41.7	$43.9
		3	1,673,384	1,763,648	2.53%	$18.0	$18.2	$20.6	$21.7
GenPower	Longview	1	4,167,850	3,816,811	6.30%	$44.9	$45.4	$51.3	$54.0
NRG	MEA	1A&1B	408,719	714,917	0.62%	$4.4	$4.4	$5.0	$5.3
AmBit	Grant Town	1A&1B	660,511	1,000,609	1.00%	$7.1	$7.2	$8.1	$8.6
Total			**66,121,477**	**67,964,805**	**100%**	**$712.2**	**$719.8**	**$813.1**	**$856.6**

^U.S. DOE, EIA-923 Monthly Generating Unit Net Generation Time Series File, 2012 Final_Release, http://www.eia.gov/electricity/data/eia923/

+ EPA Clean Air Markets Division, http://www.epa.gov/airmarkets

*Allowance Cost is the projected WV Allowance Price from CBER Report, Table 18.

**Assumes all allowances are used, unit allocation is based on percentage of 2012 generation. Total generation is reduced to level of the budget.

++Assumes percentage decrease in emissions as result of budget equals the same percentage decrease in generation.

Table 19: Absolute Cost of Compliance for 2012 Emissions & Generation in a Rate-based Plan with National Trading in 2022, 2025, 2028 and 2030
($ shown in millions except ERC unit cost)

Company	Plant	Unit	2012 Generation^ (MWh net)	2012 CO_2 Emissions+ (tons)	2012 CO_2 Emission Rate (lb CO_2/MWhnet)	2022 ERC Cost* @ $11.41	2025 ERC Cost* @ $15.02	2028 ERC Cost* @ $19.64	2030 ERC Cost* @ $24.68
					State Emission Rate Goal (lb CO_2/MWhnet)	**1,671**	**1,500**	**1,380**	**1,305**
AEP	John E. Amos	1	3,865,506	3,937,978	2,037	$9.7	$20.8	$36.2	$53.5
		2	3,592,334	3,586,863	1,997	$8.0	$17.9	$31.5	$47.0
		3	5,511,206	5,536,156	2,009	$12.7	$28.1	$49.3	$73.4
	Mitchell	1	4,055,621	4,166,944	2,055	$10.6	$22.5	$39.0	$57.5
		2	3,488,717	3,528,856	2,023	$8.4	$18.3	$31.9	$47.4
	Mountaineer	1	8,292,574	8,716,837	2,102	$24.4	$50.0	$85.2	$125.0
First Energy	Ft. Martin	1	3,694,783	3,686,690	1,996	$8.2	$18.3	$32.4	$48.3
		2	1,859,912	1,892,934	2,036	$4.6	$10.0	$17.4	$25.7
	Harrison	1	3,030,458	3,193,111	2,107	$9.0	$18.4	$31.4	$46.0
		2	3,203,134	3,157,607	1,972	$6.6	$15.1	$27.0	$40.4
		3	3,774,607	3,997,839	2,118	$11.5	$23.4	$39.7	$58.1
	Pleasants	1	4,113,316	4,149,695	2,018	$9.7	$21.3	$37.3	$55.4
		2	3,868,524	3,849,537	1,990	$8.4	$19.0	$33.6	$50.1
Dominion	Mt. Storm	1	3,471,365	3,668,691	2,114	$10.5	$21.3	$36.2	$53.1
		2	3,388,956	3,599,082	2,124	$10.5	$21.2	$35.9	$52.5
		3	1,673,384	1,763,648	2,108	$5.0	$10.2	$17.3	$25.4
GenPower	Longview	1	4,167,850	3,816,811	1,832	$4.6	$13.8	$26.8	$41.5
NRG	MEA	1A&1B	408,719	714,917	3,498	$5.1	$8.2	$12.3	$17.0
AmBit	Grant Town	1A&1B	660,511	1,000,609	3,030	$6.1	$10.1	$15.5	$21.5
Total			**66,121,477**	**67,964,805**	**2,056**	**$173.7**	**$368.0**	**$635.9**	**$938.8**

^U.S. DOE, EIA-923 Monthly Generating Unit Net Generation Time Series File, 2012 Final_Release, http://www.eia.gov/electricity/data/eia923/

+ EPA Clean Air Markets Division, http://www.epa.gov/airmarkets

*ERC Cost is the projected U.S. ERC Price from CBER Report, Table 20.

Table 20: Absolute Cost of Compliance for 2012 Emissions & Generation in a Rate-based Plan without Trading in 2022, 2025, 2028 and 2030 *($ shown in Millions except ERC unit cost*)

Company	Plant	Unit	2012 Generation^ (MWh net)	2012 CO_2 Emissions+ (tons)	2012 CO_2 Emission Rate (lb CO_2/MWhnet)	2022 ERC Cost* @ $102.62	2025 ERC Cost* @ $84.58	2028 ERC Cost* @ $68.85	2030 ERC Cost* @ $65.58
State Emission Rate Goal (lb CO_2/MWhnet)						1,671	1,500	1,380	1,305
AEP	John E. Amos	1	3,865,506	3,937,978	2,037	$87.0	$117.2	$126.8	$142.3
		2	3,592,334	3,586,863	1,997	$71.9	$100.7	$110.6	$124.9
		3	5,511,206	5,536,156	2,009	$114.4	$158.2	$173.0	$195.0
	Mitchell	1	4,055,621	4,166,944	2,055	$95.6	$126.9	$136.6	$152.8
		2	3,488,717	3,528,856	2,023	$75.4	$102.9	$111.9	$125.9
	Mountaineer	1	8,292,574	8,716,837	2,102	$219.7	$281.6	$298.8	$332.3
First Energy	Ft. Martin	1	3,694,783	3,686,690	1,996	$73.7	$103.3	$113.5	$128.2
		2	1,859,912	1,892,934	2,036	$41.6	$56.2	$60.8	$68.3
	Harrison	1	3,030,458	3,193,111	2,107	$81.2	$103.8	$110.0	$122.2
		2	3,203,134	3,157,607	1,972	$59.1	$85.2	$94.5	$107.3
		3	3,774,607	3,997,839	2,118	$103.7	$131.6	$139.0	$154.3
	Pleasants	1	4,113,316	4,149,695	2,018	$87.6	$120.1	$130.9	$147.3
		2	3,868,524	3,849,537	1,990	$75.8	$106.9	$117.8	$133.2
Dominion	Mt. Storm	1	3,471,365	3,668,691	2,114	$94.4	$120.1	$127.1	$141.1
		2	3,388,956	3,599,082	2,124	$94.3	$119.2	$125.8	$139.5
		3	1,673,384	1,763,648	2,108	$44.9	$57.4	$60.8	$67.5
GenPower	Longview	1	4,167,850	3,816,811	1,832	$41.1	$77.9	$93.9	$110.3
NRG	MEA	1A&1B	408,719	714,917	3,498	$45.9	$46.1	$43.2	$45.0
AmBit	Grant Town	1A&1B	660,511	1,000,609	3,030	$55.1	$57.0	$54.4	$57.3
Total			**66,121,477**	**67,964,805**	**2,056**	**$1,562.4**	**$2,072.1**	**$2,229.2**	**$2,494.6**

^U.S. DOE, EIA-923 Monthly Generating Unit Net Generation Time Series File, 2012 Final_Release, http://www.eia.gov/electricity/data/eia923/

+ EPA Clean Air Markets Division, http://www.epa.gov/airmarkets

*ERC Cost is the projected ERC Price in WV from CBER Report, Table 21.

Comprehensive Analysis Factor 8: The Expected Remaining Useful Life of the Unit

One of the things the WVDEP sought from West Virginia electric generating unit owners when it began this feasibility study was information regarding the remaining useful life of their units. The table below summarizes the response received concerning the remaining useful life of the West Virginia units. Based each unit's first year in operation and the information provided on useful life, where possible, estimates of remaining life is provided in brackets.

Table 21: West Virginia Unit Owner's Response Regarding Remaining Useful Life of Units

Company	Response on Remaining Useful Life of Units
Appalachian Power; Wheeling Power	None of the units has an anticipated retirement date prior to 2030
First Energy	First Energy coal-fired power plants have historically been deactivated within a 70-year lifetime [for Ft. Martin - through 2037, for Harrison - through 2042, and Pleasants - through 2049]
Dominion	Currently, there are no plans to prematurely retire the units [Mt. Storm's first unit was built in 1965]
Longview	It is reasonable to project that the useful life of the Longview unit is between 45-60 years [the earliest date would be 2056]
MEA	MEA estimates that the existing facility will be useful through 2050.
Grant Town	The current Power Purchase Agreement runs to 2036. The remaining useful life of the unit is about that time frame

Depending on the state plan approach taken, CBER – EVA's projections show that the 111(d) rule may not force premature closure of West Virginia units. The EVA projections for both of the 111(d) compliance scenarios involving national trading show the state's level of generation above or near the 2014 level of 79.2 Million MWh through 2034, when generation levels start to decline. According to CBER – EVA, the decline at that time is a result of some West Virginia units reaching the end of their useful lives rather than from the impact from the 111(d) rule. See Table 5 and Figure 10. Of course, their modeling of both of the instate-only plan scenarios show significant drops in West Virginia electricity generation, beginning with implementation of the 111(d) rule in 2022. If these state plan approaches are taken, electric generating units in the state could be at risk of retirements before the end of their remaining useful lives.

Comprehensive Analysis Factor 9: The Impacts of Closing the Unit, Including Economic Consequences Such as Expected Job Losses at the Unit and Throughout the State in Fossil Fuel Production Areas Including Areas of Coal Production and Natural Gas Production and the Associated Losses to the Economy of Those Areas and the State, if the Unit is Unable to Comply With the Performance Standard

If the state choses one of the plan alternatives with national trading, based on CBER – EVA's modeling, closure of electric generating units in West Virginia appears to be unlikely. In the state plan scenarios without trading, the CBER – EVA projected impacts are great and some unit closures may be expected. Because decisions the owners of these plants might make in such scenarios are likely to take into account factors that are unique within their corporate structure which are unlikely to be apparent to those outside that structure, the WVDEP cannot speculate as unit closure decisions. To provide the analysis this factor seeks, the WVDEP asked CBER to analyze the impacts of a hypothetical closure of each electric generating unit in the state. None of the information presented should be interpreted as a projection that any particular unit will close. The CBER analysis of hypothetical plant closures is presented below from pages 54 to 64 of its report (footnotes not included).

9.1 Approach

To provide information regarding potential impacts from unit closure in the sub-regions surrounding the power plants, CBER utilized the EMSI's input-output model. EMSI produces estimates of employment and sales impacts for the sub-regions based on 2013 national input-output (I-O) tables. As these areas are defined as those surrounding the power plants, effects for other regions of the state are not included. The model only considers purchases and spending effects within the defined sub-region. Even though many of the power plant sub-regions include portions of neighboring states, only the West Virginia portions were considered in the analysis. Further, power plants may draw labor or supplies from other parts of West Virginia beyond their sub-region borders. With the exception of statewide coal employment impacts, the hypothetical closure analysis does not consider impacts outside of these sub-regions.

Power plant local sub-regions were determined using United States Census Bureau data on Commuting (Journey to Work) Flows. Sub-regions were defined on the basis of where workers reside. Closures were simulated as a reduction in employment of the affected industry, Fossil Fuel Electric Power Generation sector (NAICS 221112). Estimates of EGU direct employment and industry employment were used to approximate complete closure. Please see the appendix for more detail.

Impact estimates are illustrative and should be interpreted with care. The estimates thus reflect the potential impact of complete plant closure to the extent permissible by the data. For plants consisting of more than one unit, partial closure would result in smaller impacts than estimated. The analysis also assumes that individuals do not find other employment elsewhere within the sub-regions. Re-employment potentially mitigates overall estimated impacts by generating replacement jobs and income.

As noted previously, power plant sub-regions overlap and counties may be represented multiple times. As such estimated impacts for individual plants should not be aggregated as double counting will occur overstating aggregating impacts. Also, impacts consider only the loss of these individual sources of coal demand. As noted previously, West Virginia-based EGUs account for about 15 percent of demand for West Virginia coal. Dynamics in external markets are not captured in the analysis and may offset or exacerbate estimated impacts.

National I-O tables may underestimate in-state linkages between fossil fuel power generation and mining sectors for West Virginia. To address this limitation, potential reductions in statewide coal sales were used to estimate employment impacts to the fossil fuel production industries resulting from potential plant closure.

As noted in Table [22], the employment sub-regions of most of the power plants stretch into surrounding states. Power plant sub-regions were defined based on worker flow data, which is described in greater detail subsequently. Also noted in the table, several counties appear in more than one region – Harrison, Marion, Monongalia, Preston, and Taylor. Thus, power plant regions are not mutually exclusive and a county may be impacted by a change in operations by more than one power producer.

Table [22]: West Virginia Coal-Fired Power Plant Sub-regions

County	Power Plant	Counties in Region	State
Putnam	John E Amos	Cabell, Jackson, Kanawha, Lincoln, Mason, Putnam	WV
		Gallia	OH
Monongalia	FirstEnergy (FE) Fort Martin Power Station, Morgantown Energy Facility (MEA), Longview Power LLC	Harrison, Marion, Monongalia, Preston, Taylor,	WV
		Fayette, Greene	PA
Harrison	FirstEnergy (FE) Harrison Power Station	Barbour, Doddridge, Harrison, Lewis, Marion, Monongalia, Taylor, Upshur	WV
Marshall	Mitchell	Marshall, Ohio, Wetzel	WV
		Washington	PA
		Belmont, Jefferson, Monroe	OH
Grant	Mt. Storm	Grant, Hardy, Mineral, Pendleton, Randolph, Tucker	WV
Pleasants	FirstEnergy (FE) Pleasants Power Station	Pleasants, Ritchie, Tyler, Wood	WV
		Washington	OH
Mason	Mountaineer	Jackson, Mason, Putnam	WV
		Gallia, Jackson, Meigs	OH
Marion	Grant Town Power Plant	Harrison, Marion, Monongalia, Preston, Taylor	WV

[Reproduced from CBER Report Table 28]

Table [23] contains socioeconomic characteristics for the West Virginia sub-regions surrounding the power plants. The region around Mitchell Power Plant is the smallest in terms of population but the highest in terms of per capita personal income, which includes all sources of income such as transfer payments and dividends for example. The sub-region for John E. Amos is the largest, with nearly 422,000 people and is situated within the largest labor market with almost 250,000 workers. With the exception of the Mountaineer sub-region, all of the power plan sub-regions have poverty rates in excess of the national average; although all are below the statewide average. Please see the appendix for a distribution of employment by industry within each sub-region.

Table [23]: Socioeconomic Characteristics of Power Plant Sub-Regions, 2014

Power Plant	Population	Total full-time and part-time employment	Average wages and salaries	Per capita personal income	Poverty Rate
Mt. Storm	96,915	46,539	$ 34,071	$ 32,688	17.4%
FE Harrison	312,398	179,330	$ 43,690	$ 38,310	17.7%
Grant Town	279,884	161,440	$ 43,956	$ 39,411	17.2%
Mitchell	91,732	56,572	$ 40,912	$ 40,907	16.6%
Mountaineer	112,912	47,396	$ 43,524	$ 36,207	15.5%
FE Fort Martin; MEA; Longview	279,884	161,440	$ 43,956	$ 39,411	17.2%
FE Pleasants	112,980	62,134	$ 39,109	$ 36,241	17.9%
John E. Amos	421,805	248,161	$ 42,816	$ 39,567	17.6%
West Virginia	1,850,326	914,071	$ 40,589	$ 36,132	18.4%
United States	318,857,056	185,798,800	$ 51,552	$ 46,049	15.8%

Source: CBER calculations from Bureau of Economic Analysis, Regional Economic Accounts, Census Bureau, Small Area Income and Poverty Estimates

[Reproduced from CBER Table 29]

9.2 Results

Figures [11] through [14] contain the results from the sub-regional hypothetical plant closure impact analysis. In general, the majority of impacts within each region consist of the direct effect, or the loss of sales and employment at the plant itself. Regional sales multipliers range from 1.14 to 1.25, indicating that within a given region the sales lost at additional businesses constitutes an additional $0.14 to $0.25 of lost economic activity for every dollar of lost power plant sales within the region. Sales impacts are based on the portion of industry sales retained within the sub-region.[77] Magnitude of multiplier effects, also known as the indirect and induced effect, depend on the size of the sub-regions and existence of supplier industries within the region.

[77] As noted previously, industry earnings for power generation exceed wages partly due to the inclusion of profits. Sales generated by West Virginia-based EGUs are not necessarily retained entirely within West Virginia and are likely distributed as earnings to other locations, such as where company headquarters are located. Sales not retained within the state, or power plant sub-region, constitute leakage and do not generate local economic impacts.

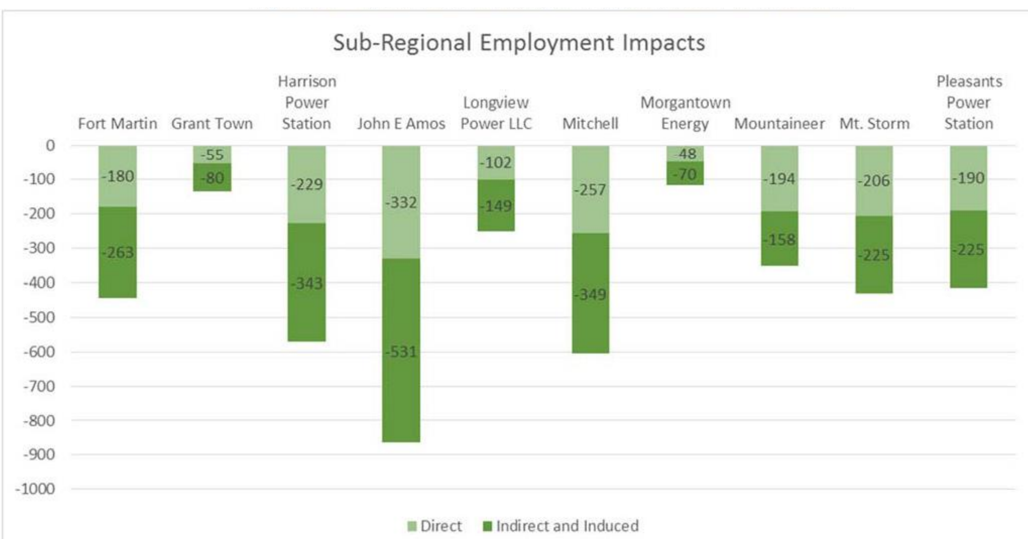
Figure [11]: Total Sub-Regional Sales Impacts from Hypothetical Plant Closures

Source: EMSI, 2015 Q3 Estimates and CBER calculations. Based on 2013 national Input-Output tables.

[Reproduced from CBER Report Figure 15]

Indirect and induced employment impacts within the sub-regions are generally larger than the direct impacts, or loss of plant employment, as displayed in Figure [12]. Multipliers associated with job impacts range from 1.8 to 2.6. As with sales, larger sub-regions generally see larger impacts in absolute terms.

Figure [12]: Employment Impacts from Hypothetical Plant Closures

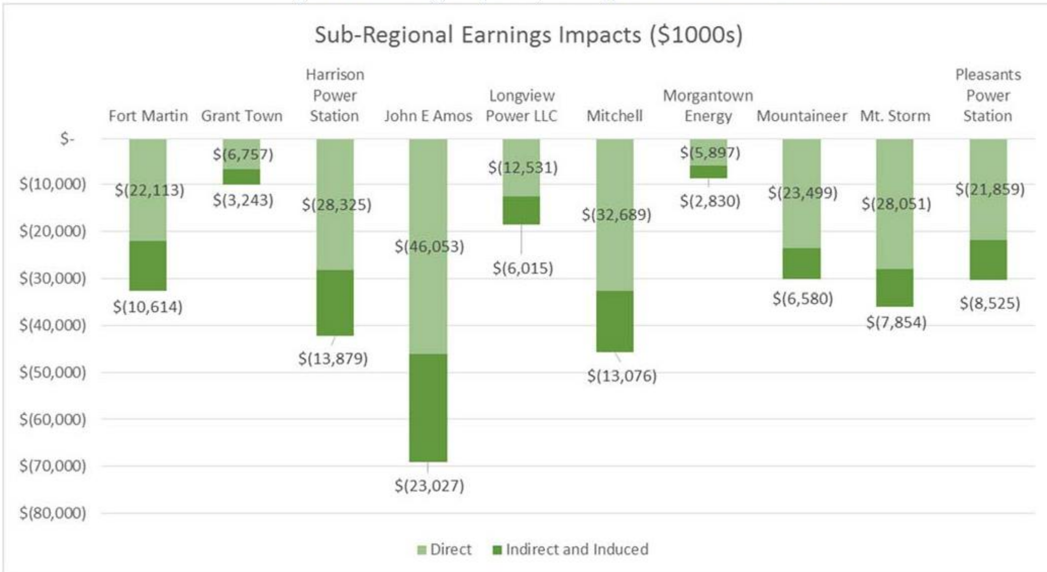


Source: EMSI, 2015 Q3 Estimates and CBER calculations. Based on 2013 national Input-Output tables.

[Reproduced from CBER Report Figure 16]

Similar to output impacts, earnings impacts are dominated by the direct effect or loss of earnings from the power plants directly. Recall that earnings includes benefits and profits. Figure [13] displays the results.

Figure [13]: Earnings Impacts from Hypothetical Plant Closures

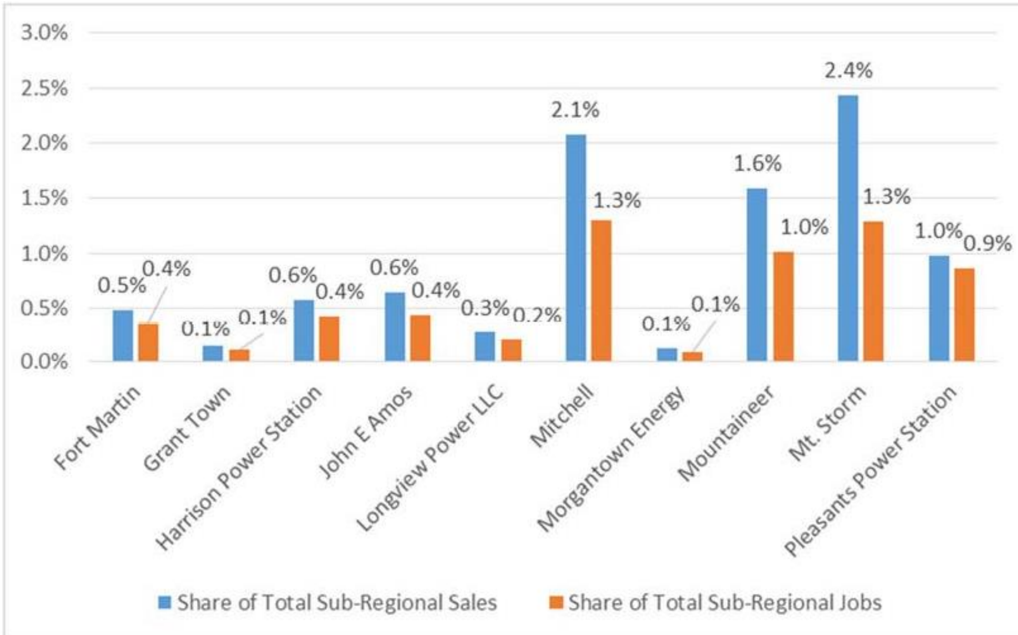


Source: EMSI, 2015 Q3 Estimates and CBER calculations. Based on 2013 national Input-Output tables.

[Reproduced from CBER Report Figure 17]

To provide additional context for evaluating hypothetical closures, losses within each sub-region were compared with the area totals. While the absolute numbers range from $35 million to $284 million in lost sales, generally representing less than 3 percent of total economic output of each sub-region. Job loss estimates range from 120 to 870 jobs, accounting for less than 1.5 percent of total sub-regional jobs. The relative magnitude of impacts vary across each sub-region. Generally speaking, for sub-regions that are relatively small in economic terms the hypothetical closure exhibits a larger proportional impact than within sub-regions that represent larger or more diverse economic areas.

Figure [14]: Impacts as Share of Sub-Regional Totals



Source: CBER calculations from EMSI, 2015 Q3 Estimates. Based on 2013 national Input-Output tables

[Reproduced from CBER Report Figure 18]

In general, the affected industry exhibits the largest individual job impact, with remaining jobs lost occurring across industries within the sub-regions. Across all sub-regions, job loss is greatest in the Government sector consistent with existing research (see Table 51 in the appendix). Lost employment within Government constitute 10 to 15 percent of the job loss within each sub-region. Health Care and Social Assistance and Retail Trade are also heavily affected sectors. Retail employment accounts for between 4 and 8 percent of lost jobs, and similarly for Health Care and Social Assistance.

These patterns are generally consistent with the distribution of employment by industry within the sub-regions (See Table 50 in the appendix.) Government tends to have the largest share of total employment, from about 15 to 22 percent across the sub-regions, followed by Health Care and Social Assistance and Retail Trade. Within the Pleasants and Mountaineer sub-regions Manufacturing also represents a substantial share, accounting for more than 10 percent of total employment in each region.

Impacts on State Fossil Fuel Industry

The potential impact hypothetical individual plant closures may have on the state's mining economy was assessed by reducing sales of bituminous coal by the estimated value of annual purchases of West Virginia coal. The estimated annual value of West Virginia coal sales to each plant was estimated using the annual average of coal consumption and delivered prices for the years 2010-2014. Table

[24] contains the estimated coal sales reductions used to model the impact of each hypothetical closure at an average delivered price of $56/ton. Sales were then allocated to the Bituminous Underground Coal Mining (NAICS 212112) (70 percent) and Bituminous Coal and Lignite Surface Mining industries (212111) (30 percent).

West Virginia Coal Sales and Severance Tax Revenues

EGU annual purchases of West Virginia coal range from $4 million to $282 million. Associated severance tax revenues range from about $248,000 to $14 million. Hypothetical premature plant closures represent a one-time permanent reduction in coal sales and severance tax revenues from a BAU scenario.

Table 24: Estimated Annual Purchases of West Virginia Coal

Power Plant	Reduction in Coal Sales	Associated Severance Tax Revenues
FirstEnergy Fort Martin Power Station	$100,985,768	$5,049,288
FirstEnergy Harrison Power Station	$282,154,231	$14,107,712
FirstEnergy Pleasants Power Station	$11,384,672	$569,234
John E Amos	$156,370,238	$7,818,512
Mitchell	$164,528,854	$8,226,443
Mountaineer	$85,776,175	$4,288,809
Mt Storm	$43,800,594	$2,190,030
Morgantown Energy Facility[113]	$4,953,995	$247,700

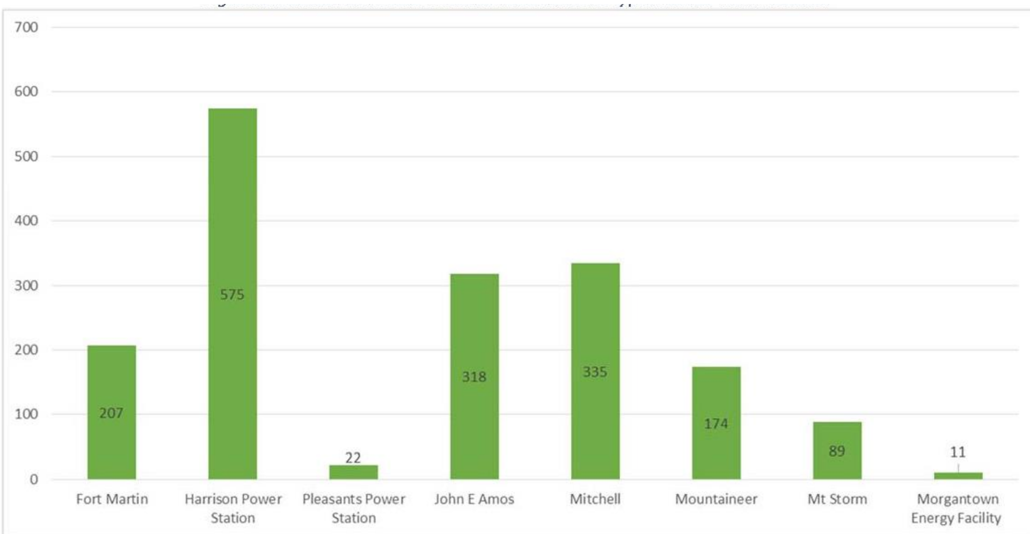
Source: CBER calculations from EIA-923 and EIA-860 Reports.

[Reproduced from CBER Report Table 30]

Employment Impacts

Within West Virginia, reductions in power generation sales lead to losses predominantly in coal mining, with Support Activities for Oil and Gas being the other affected industry within the supersector. Losses in coal mining account for 99 percent of all estimated fossil fuel-related job losses within the state. Job losses are greater for plants like Harrison that purchase larger amounts of West Virginia coal.

Figure 15: Statewide Fossil Fuel Jobs Lost due to Hypothetical Plant Closure



Source: EMSI, 2015 Q3 Estimates. Based on 2013 national Input-Output tables

[Reproduced from CBER Report Figure 19]

9.4 Coal-Fired Power Plant Depreciation

In states like West Virginia, where electricity supply remains a vertically-integrated service, the capital costs of utility power plants are paid for by ratepayers over a schedule that is determined at the time of investment. For many existing coal-fired power plants, these capital costs include fairly recent and large-scale investment in pollution control equipment made to comply with requirements of the Clean Air Act in the 2000s.

In the year 2030, all of West Virginia's remaining regulated coal-fired generating units will have about $1 billion of undepreciated book value tied to West Virginia electricity customers. Most of the units are scheduled to be fully depreciated in 2040, with a few units scheduled to be depreciated in the 2030s. For compliance scenarios where plants are closed prior to full depreciation, the remaining book value is a continuing cost to customers. The following table provides estimates of West Virginia customers' jurisdictional share of the remaining book value of regulated coal-fired power plants in the state. A portion of value is assigned to electricity customers in neighboring states and is not paid for by WV customers. These values do not include the rate of return allowed to regulated utilities on capital investment or the cost of tearing down the plants, and can thus be considered conservative in that actual post-closure costs would likely exceed book value. Table [25] displays the total value of projected remaining value.

Table 25: Projected Remaining Book Value of Active Regulated Coal Plants in West Virginia

Year End	Projected Remaining Value ($Billion) - WV Jurisdictional	Year End	Projected Remaining Value ($Billion) - WV Jurisdictional
2015	$3.163	2028	$1.316
2016	$3.021	2029	$1.174
2017	$2.879	2030	$1.032
2018	$2.736	2031	$0.890
2019	$2.594	2032	$0.748
2020	$2.452	2033	$0.635
2021	$2.310	2034	$0.528
2022	$2.168	2035	$0.421
2023	$2.026	2036	$0.314
2024	$1.884	2037	$0.207
2025	$1.742	2038	$0.117
2026	$1.600	2039	$0.039
2027	$1.458	2040	$ 0

Source: WV PSC, Utilities Division.

[Reproduced from CBER Report Table 31]

9.5 Potential tax impacts and considerations

The effects upon state and local taxation from EGU closure or a reduction in generation are difficult to quantify due to a variety of valuation approaches, rates and applicable tax credits. Effects can be broadly characterized as impacts arising from changes in revenues associated with reduced industry worker income taxes, ad valorem property taxes of utility properties and business and occupation taxes. As noted previously, reduction in state coal sales may also result in severance tax revenue losses.

Sales of electricity are exempt from the WV Sales Tax to avoid double taxation of those sales in conjunction with the (B&O) Tax.

While power plant closure may have fiscal impacts related to the value of the property and sales, income tax revenue may also decline due to employment losses, assuming individuals do not find new employment elsewhere within the state. Average wages and salaries within the power plant sub-regions range from about $39,000 to $44,000, as reported previously (see Table 29). This value falls within the 6 percent income tax bracket for West Virginia, thus the 6% rate is applied to total estimated wage and salary losses. Total wages and salaries lost for each hypothetical closure are approximated by applying the average wages and salaries within each region to the total estimated job loss.

As displayed in Table [26], total lost personal income tax revenue ranges from about $311,000 to $2.2 million. Hypothetical closures associated with larger employment losses are associated with larger losses to income tax revenue. When compared with the total personal income tax revenue collected by the state, about $1.81 billion in FY15, the losses comprise from 0.02 to 0.12 percent of total personal income tax revenues.

Table 26: Estimated Potential State Income Tax Impact from Hypothetical Plant Closure

Power Plant Sub-Region	Lost Income Tax Revenue	Share of Total State Income Tax Revenues for FY15
Fort Martin	$1,168,364	0.06%
Grant Town	$ 356,048	0.02%
Harrison Power Station	$1,499,442	0.08%
John E Amos	$2,216,994	0.12%
Longview Power LLC	$1,698,479	0.09%
Mitchell	$1,487,570	0.08%
Morgantown Energy	$ 311,212	0.02%
Mountaineer	$ 919,223	0.05%
Mt. Storm	$ 881,082	0.05%
Pleasants Power Station	$ 973,811	0.05%

Source: CBER calculations from US BEA, EMSI, WV Dept. of Revenue, and Tax Foundation data

[Reproduced from CBER Report Table 32]

For the most part, the CBER Report focuses on broader impacts to the state's economy from hypothetical plant closures. In addition to these broader impacts, pre-mature closure of coal fired units in West Virginia will impact what consumers pay for electricity. In section 9.4 of its Report, CBER provides Table 31 (Table 25 in this report) which shows, by year, the undepreciated value of West Virginia power plants that remains to be recovered from consumers through their monthly electric bills. The WV PSC allows electric utilities to recover their capital investments in generation facilities that are used to provide utility service. Recovery of the capital invested in generation facilities is factored into the rates the WV PSC sets as an allowance for depreciation and amortization of the facility that is intended to provide its owner with recovery of the full value of the asset over its useful remaining life. In addition to recovery of capital invested in generation facilities, the WV PSC also allows the owners to recover a rate of return on the net unrecovered investment in utility property. This rate of return is also included in what consumers pay for electricity.

In the event a regulated generating plant supplying electricity to West Virginia consumers is prematurely retired due to unanticipated events, the usual treatment of the unrecovered investment in that plant (the undepreciated balance) is to allow continued recovery of the unrecovered balance plus a rate of return, amortized over the original life expectancy of that plant.[78] The following table provides a further breakdown of these undepreciated balances for each the coal fired plants owned by Appalachian Power Company, Wheeling Power Company and Monongahela Power Company as of December 31, 2015.

Table 27: Undepreciated Value by Plant

Utility Company Coal Plant	Original Cost as of 12/31/2015	Reserve for Depreciation as of 12/31/2015	Total Net Unrecovered Balance as of 12/31/2015 -	West Virginia Jurisdictional Responsibility for the Unrecovered Balance as of 12/31/2015
Appalachian Power				
John Amos 1&2	$1,545,000,000	$ 502,000,000	$1,043,000,000	$ 449,000,000
John Amos 3	$1,738,000,000	$ 490,000,000	$1,248,000,000	$ 537,000,000
Mountaineer	$1,529,000,000	$ 585,000,000	$ 944,000,000	$ 406,000,000
Total APCo	**$4,812,000,000**	**$1,577,000,000**	**$3,235,000,000**	**$1,392,000,000**
Wheeling Power				
Mitchell *	**$ 973,000,000**	**$ 380,000,000**	**$ 593,000,000**	**$ 593,000,000**
Monongahela Power				
Ft. Martin	$1,073,000,000	$ 470,000,000	$ 603,000,000	$ 603,000,000
Harrison	$1,539,000,000	$ 892,000,000	$ 647,000,000	$ 647,000,000
	$2,612,000,000	**$1,362,000,000**	**$1,250,000,000**	**$1,250,000,000**
Total Regulated WV Plants	**$8,397,000000**	**$3,319,000,000**	**$5,078,000,000**	**$3,235,000,000**

* The values shown for the Mitchell Station reflect only Wheeling Power Company's 50% ownership share of the plant.

If all of these facilities were forced to close for reasons beyond the control of the utility companies, West Virginia electric consumers could be required to pay for the amortization of the outstanding $3.2 billion jurisdictional balance of the investment, plus a rate of return on this balance, even though the consumers are no longer deriving any benefit from those plants. In addition, if the utilities build new plants to replace this lost generation, customers may also be required to provide a recovery of the capital invested in the replacement generation, plus a rate of return.

On a levelized basis, recovery of the undepreciated balance for existing plants is estimated to comprise $14.75 of the monthly cost of electricity to a typical residential customer using 1,000 KWh by per month, or $177 per year. As rates are currently set, consumers will continue to pay this amount per month through the year, 2040, when this obligation will be fully recovered.[79] The following table shows the total of unrecovered investment amounts and

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78 This may be tempered by facts and circumstances that might lead the WV PSC to disallow recovery of a portion of the unrecovered cost, or to spread out the recovery over a longer period of time. Normally, disallowances would be based on some concern about the prudence of utility actions leading up to the premature retirement.

79 Foreseeably, if a number of West Virginia power plants are forced to close and replacement generation needed to be built, new rates reflecting the changes would need to be set by the WV PSC. At that time, the WV PSC might consider the appropriate way to allow recovery of the outstanding jurisdictional balance for existing plants being shut down to proceed, in addition to its consideration of capital recovery for any new plants that are built.

associated rate of return (carrying charges) that would remain at various points in time over the projected twenty-five year remaining useful life of the plants. Column 5 in the table shows the total cost this typical residential consumer (using 1,000 KWh per month of electricity) will be paying for these plants in their monthly electric bills from the year shown in column 1, through 2040.

Table 28: Total of Unrecovered Investment Amounts and Associated Rates of Return (Carrying Charges) Over the Projected Twenty-five Year Remaining Useful Life of Power Plants

1	2	3	4	5
Year Ending	**West Virginia Jurisdictional Unrecovered Balance**	**Estimated Carrying Costs Obligation**	**Total Cost to Consumers for Amortization and Carrying Cost of Unrecovered Balances**	**Cost From Retirement Year to 2040 For WV Residential Consumers Using 1,000 KWh per Month of Electricity**
2016	$3.089,000,000	$3,858,000,000	**$6,947,000,000**	$4,248
2020	$2,508,000,000	$2,351,000,000	**$4,859,000,000**	$3,540
2025	$1,784,000,000	$1,224,000,000	**$3,008,000,000**	$2,655
2030	$1,059,000,000	$ 477,000,000	**$1,536,000,000**	$1,771
2035	$ 434,000,000	$ 96,000,000	**$ 530,000,000**	$ 885
2040	$ -	$ -	**$ -**	-

Electric bills in West Virginia already include the cost of electric units that have previously been withdrawn from service. In June 2015, APCo (AEP) closed the Kanawha River, Glen Lyn and Sporn generating plants after more than 60 years of continuous operation. At the time of closure the West Virginia jurisdictional responsibility for these plants was approximately $40 million. The WV PSC allowed rate recovery to amortize the unrecovered balances, plus carrying costs, for these plants over the next twenty-four years. Because these plants were much closer to the end of their useful lives and the investment cost of these plants had been substantially recovered as of the date of closing, the levelized impact on the typical APCo customer is approximately $3.84 per year, or an aggregate total cost of $92 over the next twenty-four years.

Comprehensive Analysis Factor 10: Impacts on the Reliability of the System

EPA has projected that 45% of the coal fired generation that existed in 2012 will no longer be available by 2030.[80] In West Virginia, six electric generating units have retired since 2012, removing almost 2,300 MW from the state's capacity.[81] Ordinarily the reliability planning

80 AEP's "Response to the Clean Power Plan Data Request from the WVDEP," November 6, 2015, p. 19.

81 Against this lost capacity, it should be noted that a 631 MW gas-fired unit planned for Marshall County, West Virginia has obtained a permit from the WVDEP's DAQ. A permit application for another similarly sized gas-

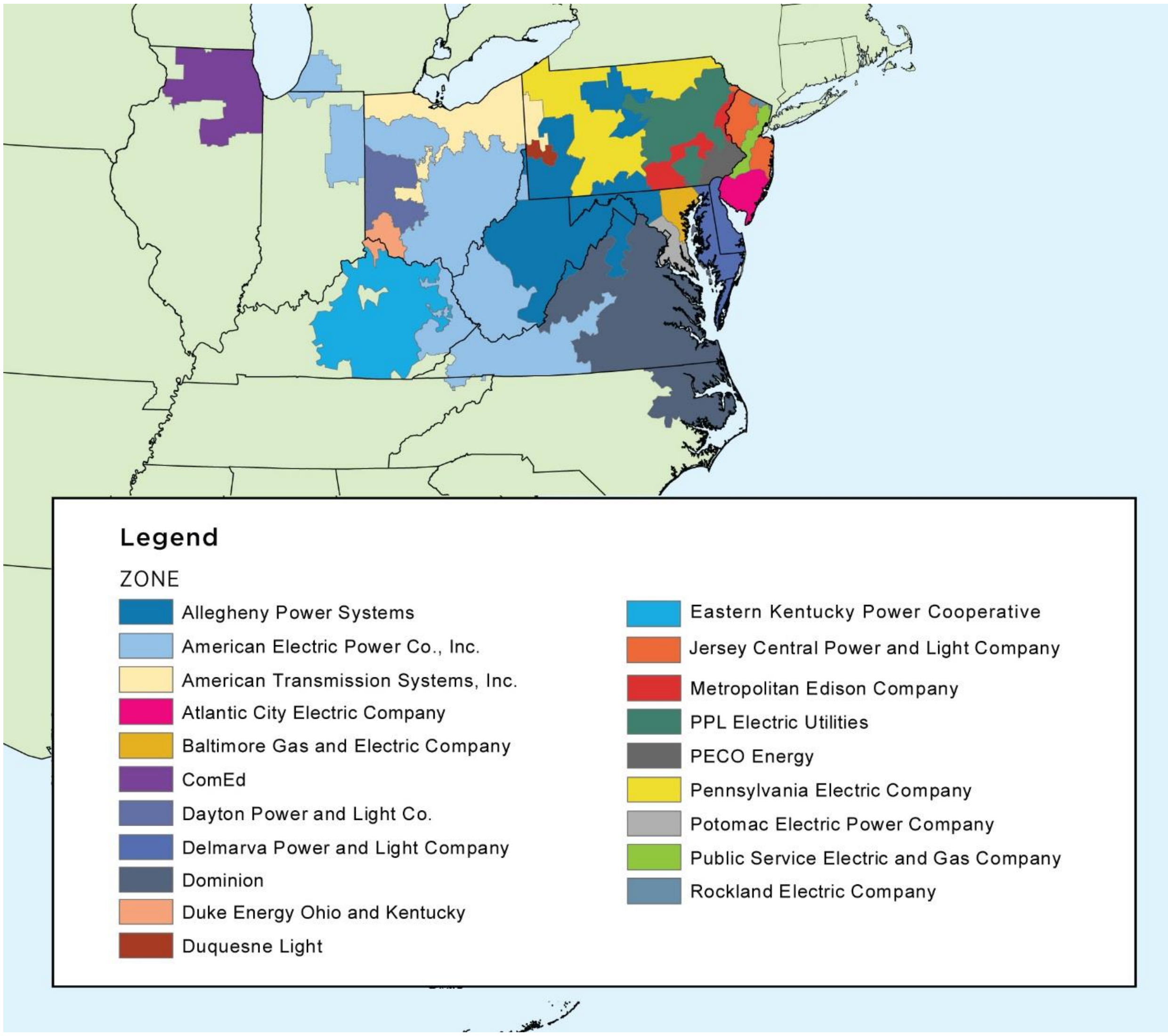
window for major utilities is a 10 – 12 year period or more for retirements, replacement generation, transmission lines, etc. Against this planning window, consider that EPA finalized the 111(d) rule in 2015 and established 2022 as the beginning of the interim compliance period allowing much less than the ordinary planning time to adapt and plan. The Supreme Court's stay of the rule has given the electric generation industry, the states and the various entities involved in assuring the reliability of the system additional time.

The "grid" in the lower 48 states is made up of the Eastern Interconnection, Western Interconnection and the Texas Interconnection. West Virginia is entirely within the area of the Eastern Interconnection that is operated by PJM, a regional transmission organization. PJM is subject to oversight by the Federal Energy Regulatory Commission (FERC). FERC is the federal agency with jurisdiction over grid reliability, interstate electricity sales and wholesale electric rates. FERC has oversight over North American Electric Reliability Corporation (NERC) in NERC's role as the electric reliability organization (ERO) for North America. On the state level, the WV PSC regulates electric utilities, as well. In terms of planning for reliability of the system, there are multiple reliability measures embedded in FERC, NERC, PJM and the WV PSC requirements that West Virginia's EGUs must meet.

The two main providers of electricity in the state are subsidiaries of American Electric Power and First Energy (Allegheny Power Systems) (see Figure 16 below for Map of PJM Interconnection Service Territories.

fired unit planned for Brooke County has been submitted. Developers of a gas-fired unit planned for Harrison County have had pre-application meetings with the DAQ.

Figure 16: Map of PJM Interconnection Territory



Source: PJM www.pjm.com/~/media/about-pjm/pjm-zones.ashx Last visited April 15, 2016

The current apparatus for assuring grid reliability in North America is the product of evolution over many years and many different challenges to the reliability of the system. The most recent significant challenge, the polar vortex in January, 2014, moved the region into the current paradigm in reliability and capacity planning. Arctic air swept across the eastern United States, bringing record cold temperatures, 20 – 30 ºF below normal for an extended time. Cold weather and fuel availability caused 35,000 MW of generation to be out of service. Despite these outages, the reliability of the system was, for the most part, maintained. However, this event did cause NERC, PJM and FERC to all produce assessments of the event, analyzing how reliability was maintained and making recommendations for the future. The polar vortex experience caused PJM to significantly restructure its regional capacity market, a mechanism it uses to assure generation capacity is available when needed. FERC approved most of the changes PJM proposed to its capacity market in the summer of 2015. An element of PJM's justification for the changes that FERC accepted was that the region is facing a large number of coal plant retirements. Although the changes to the PJM capacity market do not specifically account for changes induced by EPA's rule, they are an attempt to address issues posed by foreseeable coal retirements. Integrated Resource Plans (IRPs) West Virginia utilities filed with the WV PSC in December, 2015, illustrate the additional challenges to them posed by the restructured PJM capacity market. Both Appalachian Power and Monongahela Power forecast capacity shortfalls in the coming years. Monongahela Power expects a 700 MW shortfall by 2020. Appalachian Power expects a capacity shortfall as a result of the new PJM rules beginning in 2021. Both are planning to address these forecast shortfalls.

Those who are tasked with planning for grid reliability are actively examining the challenges posed by implementation of the EPA rule. In January, 2016, NERC released its "Reliability Considerations for Clean Power Plan Development", in which it acknowledges:

> Compliance with the CPP will accelerate an ongoing shift in the generation mix, with retirements of baseload generators or additions of variable energy resources. In order for Reserve Margin analysis to continue providing value as a resource adequacy metric, additional consideration is needed regarding how planning entities develop their Reserve Margin levels. The forced outage rates of a generation fleet will be impacted both by changes in the generation mix and by changes in the way the current resources are used, such as from increased cycling of coal units. These impacts need to be assessed and incorporated as Reserve Margin metrics are enhanced, and they should be considered as we develop more sophisticated reliability planning methods.[82]

NERC is working on modeling specifically to assess the impact of the EPA rule on reliability. Its final (Phase II) assessment on this subject was to be released at the end of March, 2016, but as of this writing, it has yet to be released. PJM is also actively engaged in modeling and assessing grid reliability specifically in light of the final 111(d) rule. PJM's reliability assessment in light of the final 111(d) rule is expected to be released in July, 2016.

The 111(d) rule includes a "reliability safety valve" (RSV).[83] However, the RSV appears to be of extremely limited utility. It only applies in emergency, catastrophic circumstances, requires notice to EPA within forty eight hours of an event triggering its use, and requires the units involved to have a sufficient number of allowances or ERCs to make their emissions legal in any event. Another concern about the RSV is that, in the proposed rule establishing a federal 111(d) plan and model state trading rules, EPA has made the observation that it believes an RSV is unnecessary in a federal plan:

> In the final Clean Power Plan EGs, the EPA laid out the availability of a reliability safety valve that could be used if an unanticipated catastrophic emergency caused a conflict between maintenance of electric reliability and inflexible requirements that a state plan might impose on an affected EGU or EGUs. Under the federal plan, inflexible requirements are not imposed on specific plants. Rather as explained earlier, the very

[82] NERC - Reliability Considerations for Clean Power Plan Development website, Jan 2016, pg. 12, retrieved March 14, 2016: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf

[83] 40 C.F.R. § 605785(e)(1).

> nature of the federal plan, in which affected EGUs can obtain allowances or credits if needed, supports reliability. Therefore, a reliability safety valve for the federal plan is not needed.[84]

The "flexibility" EPA believes to exist in a federal plan is simply the ability to engage in trading allowances/ERCs. This observation by EPA raises the question of whether the model trading rules it is developing for states to use will also embody the view that the ability to trade allowances/ERCs provides enough flexibility to obviate the need for a RSV and, therefore, will preclude use of the RSV by states that adopt trading rules.

From a state plan perspective, West Virginia can do its part to prevent the 111(d) rule from posing grid reliability issues by adopting a state plan approach that minimizes the impact on our electric generating units, in comparison to business as usual. Based on the projections from the CBER – EVA modeling, either of the state plan scenarios involving national trading should minimize these impacts.

Comprehensive Analysis Factor 11: Any Other Factors Specific to the Unit That Make Application of a Modified or Less Stringent Standard or a Longer Compliance Schedule More Reasonable

The language used in this factor follows that of one of EPA's regulations governing the general approval process for any section 111(d) state plan, 40 C.F.R. § 60.24(f)(3), which provides:

> Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities, States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> . . .
>
> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

The important limitation, here, is that a state's authority to prescribe less stringent standards or longer compliance schedules based on unit-specific characteristics exists, "*unless otherwise specified* in the applicable subpart".

In the applicable subpart for existing electric generating units, 40 C.F.R., Subpart UUUU, EPA specifies otherwise in a couple of ways. First, 40 C.F.R. § 60.5740(b) which governs content of a state plan submission precludes the application of 40 C.F.R. § 60.24(f): "the provisions of § 60.24(f) shall not apply." In addition, 40 C.F.R. §§ 60.5770(c) and (d) speak directly to the allowable length of a compliance period. In short, compliance periods longer than

[84] 80 Fed.Reg. 64981 – 2 (October 23, 2015).

the interim period, each interim step and the final step are prohibited. Accordingly, longer compliance schedules are not available under EPA's 111(d) rule. Another provision in Subpart UUUU, 40 C.F.R. § 60.5855(b), speaks to the possibility of less stringent standards. This rule permits a state to allow individual units to meet standards that differ from EPA's, "provided that you demonstrate that the affected EGUs in your State will collectively meet their CO_2 emission performance rate."[85] In other words, a state that allows a particular unit to meet a less stringent standard must make up for it by requiring its other units to meet more stringent standards so, collectively, all units meet the aggregate limit for the state. Any circumstances that might justify treating one unit more favorably at the expense of other units is a matter that may be better addressed at the time a state plan is actually developed rather than in the discussion of whether a state plan is feasible.

An alternative to less stringent standards for units whose circumstances may justify it exists under a mass-based plan. In a mass-based state plan, the state has great flexibility in the way in which it allocates allowances to the different units in the state. A variety of different policy outcomes can be encouraged in the way allowances are distributed. "Fairness" or other circumstances which may justify more favorable treatment of a particular unit can be addressed through the methodology for allowance allocation. There is a summary below in the section on policy decisions in adopting a state plan that presents information on different alternatives in distributing allowances.

c. Considerations in State Plan Development

This section provides information that may be useful to decision makers who will be considering the choices that would be made in adopting a state plan, should EPA's rule survive judicial review.

1. Policy Choices

There are a number of choices to be made in adopting a state plan. The merits of some of the major choices are discussed below. This discussion is meant to provide policy decision makers with a basic understanding of the major policy decisions involved should the state develop a state plan.

State Plan vs. Federal Plan

The first choice is whether to adopt a state plan. The state is forced to confront this issue only if the EPA rule survives the judicial challenges. At that point, West Virginia's choice is whether it will make the policy decisions that must be made in a state plan or allow EPA to make these choices for it, instead. EPA has proposed a rule for the adoption of a federal plan. It will be ready to finalize its federal plan for any state that either misses the deadline for making the initial submission to EPA under the 111(d) rule, fails to meet a subsequent deadline for state plan development, submits an un-approvable state plan or simply chooses to accept imposition of the federal plan. EPA's proposal includes rate- and mass-based federal plans. EPA will decide which one of these approaches it will take when it finalizes a federal plan. The choice among all

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85 Ibid.

of the plan approaches will be made by EPA. If West Virginia decides to develop a state plan, the choice among these approaches and on each of the other policy issues outlined below will be made by the state, not EPA, subject to approval by the Legislature under W.Va. Code § 22-5-20(b).

Although the approach EPA proposes in its federal plan rule may not necessarily be the one it will take, several of the choices it proposes in this rule may be important in considering whether to adopt a state plan. In the mass-based proposal, EPA would adopt all three of the set-aside programs it created in the 111(d) rule. For West Virginia, this means that the allowances that might otherwise be available to electric generating unit owners for the initial, 2022 – 2024, compliance period would be reduced by about 10% and for subsequent compliance periods, the available allowances would be reduced by 5%. Those who obtain the set-aside allowances (renewable energy developers and projects for energy efficiency in low income communities) could then sell them in the marketplace. There is no guarantee these set-aside allowances would make it into the hands of West Virginia EGU owners. EPA's proposed plan would also direct allowances for EGUs that cease operations into its RE set-aside program instead of allocating them to the remaining operating EGUs. An alternative EPA is considering would simply cancel such allowances. EPA has also indicated that its plan would not include the reliability safety valve.

Two Year Extension

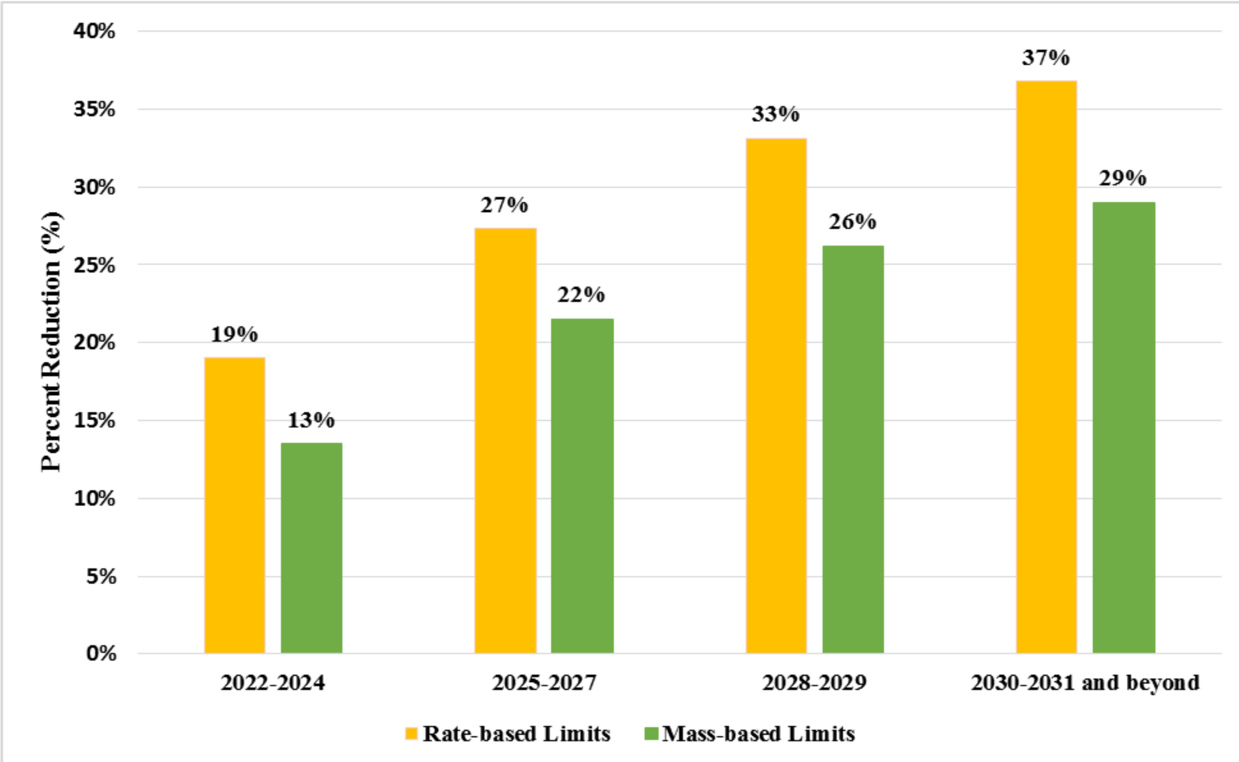
With the Supreme Court's stay of EPA's rule, all deadlines it contains are stayed. Should the rule survive judicial review unchanged, the WVDEP anticipates that EPA will be required to set new deadlines following the final court decision that will provide similar amounts of time to what EPA's rule originally allowed for state actions. An initial decision for a state under the EPA rule is whether to submit a complete state plan or make an "initial submittal" by EPA's initial deadline. In the rule, this initial deadline is September 6, 2016. The requirements for an initial submittal are minimal. If this submittal is made, the state gains a two year extension of the time to make a complete state plan submission. Although an initial submittal is intended to allow states additional time to develop a state plan, it does not bind the state to submit a plan at the end of the extension.[86] To have time to obtain the necessary changes to W.Va. Code § 22-5-20, promulgate legislative rules establishing the state plan requirements and obtain legislative approval of a state plan without a special session of the Legislature, the state will need a two year extension and probably longer, if a state plan is to be developed. There do not appear to be any drawbacks from obtaining a two year extension.

Mass-based Plan vs. Rate-based Plan

The chart below depicts the percentage reduction limits EPA's rule establishes for West Virginia for both the rate-based approach and the mass-based approach for each interim compliance period and final compliance beginning in 2030. Beneath it, are summaries of the various features of mass- and rate-based approaches to a state plan.

[86] If an extension is granted, the state is supposed to submit a report on its progress toward a state plan after one year. There are no consequences specified, however, for failing to make this report.

Figure 17: West Virginia Required Percent Reductions from Baseline: Rate-Based and Mass-Based Limits



Mass

- Cuts CO_2 emissions by reducing overall emissions by a set percentage. EPA intends to create room for lower and zero CO_2 emission generation in the market for electricity though the elimination of this percentage of coal emissions.

- For West Virginia, EPA's limit of a 29% reduction in the number of tons of CO_2 emitted from existing coal plants in the state by 2030 is equal to a reduction of 21 million tons from 2012 levels.

- West Virginia's CO_2 emissions have already been reduced by the closure of six coal plants that emitted 4.4 million tons of CO_2 in 2012. This provides a jumpstart toward meeting EPA's mass limit for the state. The 4.4 million tons of CO_2 these plants produced is 6% of the 2012 total. Assuming other coal plants in the state have not increased their output since then, the state will need additional reductions of 23% or 16.6 million tons from 2012 levels to reach EPA's final mass limit.

- In the absence of viable CCS technology for new coal units, this set percentage reduction compels an overall decrease in use of coal across states that choose a mass-based plan.

- Any growth in demand for electricity that might accompany economic expansion is likely to be met by sources of electricity other than coal.

- There is predictability that comes from knowing that an established quantity of compliance currency, i.e., allowances, will be available. This predictability does not exist in the market for ERCs in the rate-based scenario.

- If the state distributes allowances to electric generating unit owners free of charge (the merits of different approaches to allocation of allowances, including giving them away, is presented below), the portion of their emissions the free allowances will cover has no cost of compliance with the EPA rule attached to it. For emissions in 2022 – 2024, these “free” allowances would equal 87% of 2012 CO_2 emissions. For emissions in 2025 – 2027, these “free” allowances equal 78% of 2012 CO_2 emissions. For 2027 – 2029, these “free” allowances equal 74% of 2012 emissions. For 2030 and after, these “free” allowances equal 71% of 2012 emissions. Additional allowances would have to be purchased in order for emissions in excess of those levels to comply.

- Among those who have studied the 111(d) rule is some consensus that, generally, states whose electric generation is carbon intense, like West Virginia, fare better under a mass-based plan. This is very dependent, though, on how robust the market is for allowances.

- There are three set-aside programs in which states can elect to participate, only two of which apply to West Virginia, the CEIP and RE set-asides. A set-aside program involves removing some number of allowances from the quantity the state has to allocate and distributing them to others who generate revenue by selling the allowances to EGUs that need them for compliance. This is a means of subsidizing the activities in which those who receive the allowances are engaged, e.g., production of renewable energy and energy efficiency projects. States are free to craft set-aside programs other than those EPA has developed in the rule. Adoption of any of these set-aside programs will require adoption of the rigorous EM&V requirements that are discussed below in the *rate* section.

- The CEIP set-aside is an option for the state. It would take 5.6% of the state’s allowances for the initial compliance period (approximately 3.5 million allowances) from the pool of allowances the state would otherwise have to distribute for this period and dedicate them to: (1) new wind and solar projects (RE projects) during the 2020 – 2021 period, before the 111(d) rule is implemented or (2) projects to improve energy efficiency (EE) in low income communities during the 2020 – 2021 period. For each two allowances earned from the state’s CEIP set-aside by a qualifying RE project, EPA would provide that project with a one allowance match. For each two allowances that an EE project would earn from the state’s CEIP set-aside, EPA would provide a two allowance match. RE and EE projects could then sell the allowances they have earned. The EPA match would slightly inflate the number of allowances available for compliance in the initial 2022 – 2024 period and provide a ready source of available allowances for trading when the 111(d) program begins then.

- The RE set-aside is another option for the state. It would take 5% of the state's allowances from the pool of allowances the state would otherwise have to distribute and make them available to be earned by projects for new RE. Unlike the CEIP set-aside, the RE set-aside continues for the duration of the state program under 111(d).

- Due to the way EPA has structured the 111(b) and 111(d) rules, in a mass-based compliance approach, there is potential for a shift of emissions from the pool of existing sources regulated under 111(d) to new sources regulated under 111(b) that EPA calls "leakage". EPA is requiring the states where the potential for leakage exists to make a demonstration that this potential has been avoided in their state plans. One acceptable way of making this demonstration, according to EPA, is to adopt the RE set-aside. The WVDEP does not believe West Virginia has the potential for leakage and should not be compelled to address it in development of a state plan. However, EPA has yet to confirm this in writing.

- Another option in a mass-based program is whether to accept the "new source complement" (NSC). This would involve grouping new electric generating units with existing units and making this group subject to a limit on the mass of CO_2 emissions. To compensate for adding new sources of emissions to the pool of existing sources that need allowances in order to comply, a state would receive additional allowances called the NSC. West Virginia's NSC amounts to an increase of just 1.04% in the number of allowances it would have to allocate to all units. Acceptance of the NSC is another way a state that needs to do so can address "leakage", in addition opting for the RE set-aside.

- The WVDEP believes acceptance of the NSC would inhibit development of new gas-fired generation in the state. The DAQ has issued a permit for a new gas-fired power plant in Marshall County. DAQ has received a permit application for a new gas-fired plant in Brooke County and has had pre-application meetings with the developer of another proposed gas-fired power plant in Harrison County. The number of additional allowances West Virginia would receive via the NSC will not cover the emissions from the one unit for which a permit has been issued. If the state opts for the NSC, all of these plants would be additional competitors in the marketplace for allowances. If the state does not opt for the NSC, none of these plants would need allowances. Instead, all of them would be regulated under EPA's 111(b) rule as new sources. Because all of them will employ the newer, highly efficient natural gas combined cycle design that is capable of complying with the emissions rate limits of EPA's 111(b) rules for new gas-fired units, these plants would not be expected to face any difficulty in complying with the 111(b) rule.

- Air regulators and electric generating unit owners have over 20 years of experience in operating trading programs in a mass-based trading structure.

- A mass-based plan is much easier to administer than a rate-based plan, primarily because a mass-based plan does not required the rigorous EM&V that is necessary for a rate-based plan. However, EM&V is required in states with mass-based plans if those states choose to include the CEIP or RE set-asides as part of their state plans,

Rate

- Establishes an emissions rate limit that no coal fired unit can meet, but allows these units to comply by adjusting their emissions rate based on the number of ERCs they acquire. ERCs are generated by new zero or low CO_2 emissions power generation, or if a state chooses, by reduction of demand for electricity through energy efficiency measures.

- In this scenario, coal plants are forced to directly subsidize the renewable energy that replaces them by being required to purchase the ERCs the renewable energy generates.

- For West Virginia, EPA's rate-based limit is a 37% reduction from 2012 levels by 2030.

- Coal fired generation at existing plants can rise under a rate-based approach. The amount of coal generation is limited only by the numbers of ERCs that are available to yield a compliant emission rate.

- The amount of compliance currency, i.e., ERCs, which will be available is uncertain, particularly at initial implementation of the 111(d) rule. This may provide greater incentive to participate in the CEIP in order to generate a supply of available ERCs at initial implementation.

- A version of the CEIP (discussed above under *Mass*, starting at page 88) tailored to rate-based ERC trading is an option the state can elect to adopt in a rate-based program. This program would help develop a pool of ERCs that would be available when implementation of the 111(d) rule begins.

- The six coal plant closures since 2012 have no impact on electric generating units' ability to meet EPA's rate-based limit.

- Coal plants have compliance costs for every hour they operate because they will always be producing at a CO_2 emissions at a rate that exceeds the EPA limit, requiring the purchase of ERCs.

- The prevailing thought among those who have studied the 111(d) rule is that, generally, states with new nuclear generation coming online or large amounts of renewable energy fare better under a rate-based approach. If this line of thinking is borne out in state plan decisions, it could significantly curtail the number of allowances available for trading in mass-based plans because these states, which may have allowances to spare in a mass-based scenario, are believed to be likely to choose the rate-based approach.

- A rate-based plan is much harder to administer, primarily because of the rigorous EM&V requirements which will require creation of an entirely new bureaucracy to approve and track ERCs. The Division of Air Quality estimates that five new FTEs would need to be added to staff functions related to ERCs.

- West Virginia air regulators and electric generating unit owners have no experience operating a trading program in a rate-based regulatory structure.

- Part of the process for approval of ERCs is the right to appeal the decisions the state makes to award ERCs. Foreseeably, environmental groups could aggressively utilize the appeals process to keep ERCs that coal fired generation needs in order to be able to comply from being available on the market.

Emission Standards or State Measures Approach

The emission standards approach is considered "presumptively approvable" if it is based on the EPA's model trading rules. This is also the type of plans that historically have been implemented in West Virginia. Both WVDEP and the affected EGUs are familiar with how this type of plan is implemented. The emission standards approach also offers a degree of certainty that is missing from the state measures approach. In a state measures approach, state would chart its own course for achieving emissions reductions.

States that choose a state measures approach will have the burden of making an initial demonstration to EPA that the state measures will achieve the emissions reductions EPA seeks. A robust EM&V program is also a necessity in a state measures plan. If the state plan relies on the state measures approach, the state must also submit a federally enforceable "backstop" as part of its plan.[87] The backstop must include emission standards for affected EGUs that will be put into place if the state measures approach fails to achieve the required reductions. Essentially, a state that chooses a state measures approach must develop two state plans: the state measures plan that is its primary choice and an emissions standards plan that is implemented as a backstop should the state measures fail to achieve the required emissions reductions.

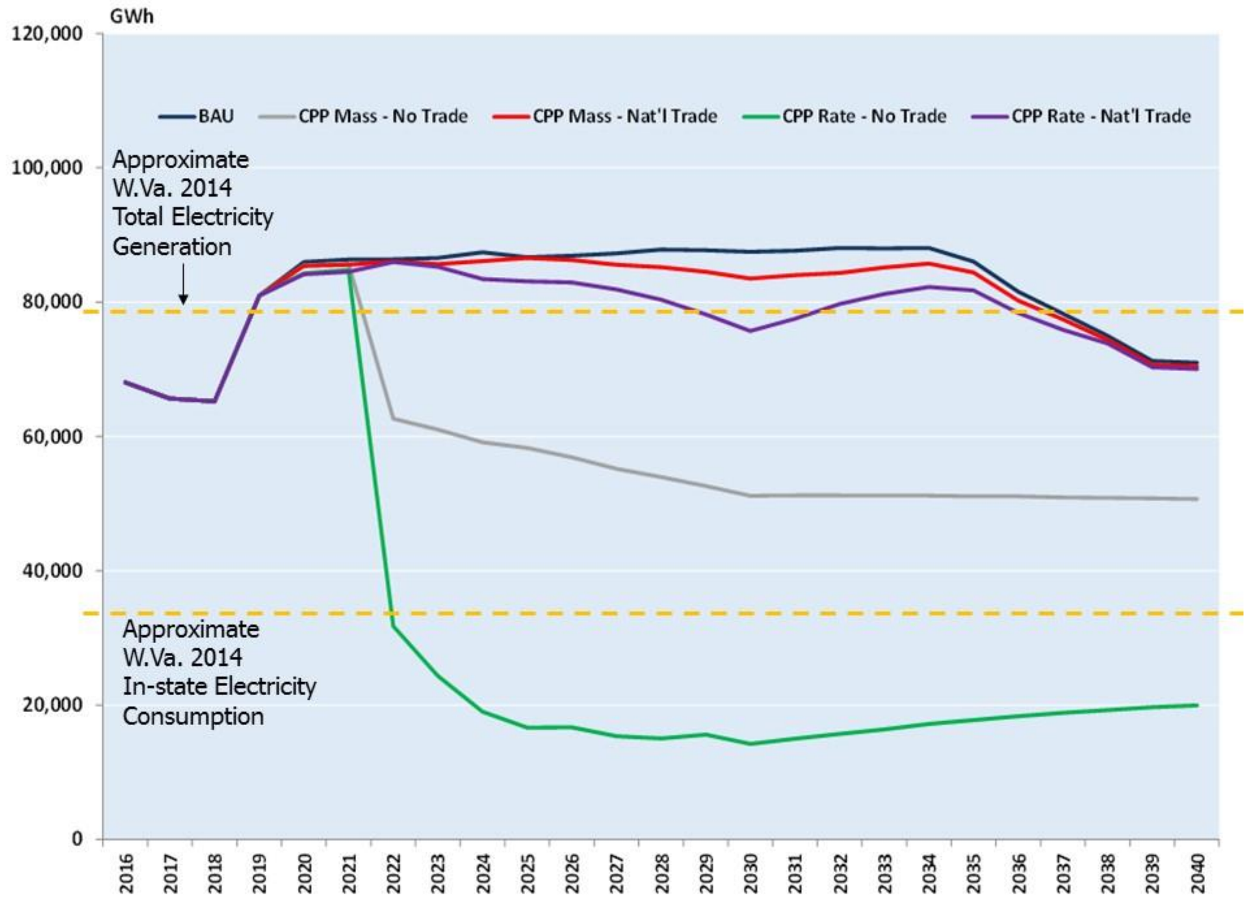
The state measures approach was designed primarily for states that have existing programs for renewable energy and energy efficiency or other existing or planned approaches to reduce carbon dioxide that are not limited to electric units. California and the Regional Greenhouse Gas Initiative (RGGI) states in the northeast may choose the state measures approach because they currently take a broader multi-sector approach to carbon regulation rather than focusing on solely on electric generating units.

[87] 40CFR § 60.5740(a)(3)

Trading, No Trading, Extent of Trading

Another policy decision is whether the state plan should include trading. If the state plan includes trading, the extent of trading must be decided. The EPA's rule contemplates instate-only, multistate and national trading. As discussed above, the CBER report modeled scenarios to demonstrate the impact of national trading for both the rate-based and mass-based options. Figure 18 shows that CBER – EVA's modeling of both of the national trading scenarios follow the business as usual scenario more closely than the non-trading (intrastate trading) scenarios. In the latter two scenarios, their modeling shows a considerable drop in generation after the EPA rule is implemented. Preliminary modeling results the WVDEP has seen from other groups also project much less impact if state plans include robust trading on a regional or national level.

Figure 18: West Virginia Coal-Fired Power Generation Projections (GWh), BAU compared to Compliance Scenarios



Source: EVA Analysis
[Reproduced from CBER Report, Figure 5 – modified by WVDEP, to show West Virginia 2014 Electricity Generation and Consumption. CBER calls the instate-only trading options "No Trade."]

EPA is expected to finalize model trading rules for states during the summer of 2016 for both rate-based and mass-based state plans. The rules are intended to provide a presumptively approvable trading regime for states. Absent restrictions imposed at the state level by other states, electric generating units in any state that adopts the model trading rules for mass-based state plans will be able to trade allowances with units from other states that have adopted these model rules. Similarly, absent state imposed restrictions, units in states that have adopted the model trading rules for rate-based state plans will be able to trade ERCs with units in other states that have adopted the rate-based model rules. As the state trading rules are proposed, units in mass-based programs would not be able to trade with units in rate-based programs. In comments on the proposed model trading rules, the WVDEP urged EPA to develop a means of converting allowances to ERCs, and vice versa. This would enable states to achieve the economies of scale that would be available from trading in the largest possible market. It would also avoid the scenario that might be possible if most carbon intense states chose mass-based state plans and most states with extensive portfolios of low or no carbon emissions generation chose rate-based state plans. In this scenario, the mass-based states might find the number of allowances available to meet demand small and the rate-based states might find an excess of ERCs on the market with few buyers. Trading between mass and rate-based plans would alleviate this problem.

It remains to be seen whether the model trading rules that EPA finalizes will contain any conditions that might make them undesirable. As discussed above in the section on reliability, starting at page 81, EPA has said that there is no need for a reliability safety valve (RSV) in the federal plan it has proposed because a robust trading market will provide sufficient flexibility to make the RSV unnecessary. The same robust trading opportunities that EPA believes make the RSV "unnecessary" in its federal plan are available to states in the model trading rules. Therefore, it is possible that EPA's thinking could on the lack of necessity for the RSV in a federal plan could carry over into the final model trading rules, which were proposed as part of the same rulemaking with the federal plan. Until the model trading rules are finalized, it remains to be seen whether this and other potentially undesirable policy choices EPA has proposed to make in the federal plan will find their way into the state trading rules as conditions on the ability of states to engage in trading under the model rules.

Multistate trading is available under EPA's rule. Some preliminary modeling WVDEP has seen suggests that West Virginia may fare better trading in certain select regional combinations of states than in a national trading scheme. Regional trading can be accomplished in a couple ways. One way is to develop a regional plan in which all individual state limits for the region would be melded into one limit for the region and all units in the region could trade with other units in the region. All states in the region would submit the same regional plan to EPA for approval. This would require extensive negotiations among states and the agreement of all states involved on each of the policy decisions that must be made in a state plan. This may be unwieldy and impractical. Such an agreement may also require the consent of Congress under the Compacts Clause of the United States Constitution. Another way to engage in regional trading would involve each state developing its own individual plan, but as to trading, all states would have identical provisions governing trading units (either allowances or ERCs) along with the agreement of all states to trade only among the states that are part of this regional arrangement. This situation may facilitate regional trading without requiring the consent of Congress.

Allocation of Allowances in a Mass-based Trading Plan

The most important policy decision the state will make in a mass-based trading program is how to distribute allowances. Allowances can be distributed free of charge, sold at auction or otherwise, placed in a set-aside program to provide a subsidy for desired policy outcomes (see the discussion of the CEIP and RE set-asides under *Mass*, starting at page 88), or be utilized in some combination of these approaches. The decision is important not just because of the ways allowance distribution can be used to encourage policy outcomes, but also because of the immense value involved. Even if allowances are distributed to electric generating unit owners free of charge, tremendous amounts of value will be changing hands. In 2022, the EPA rule gives West Virginia allowances for 62,557,024 tons of CO_2 emissions. Under a national mass-based trading program, EVA projects an allowance price of $4.35 in 2022,[88] which gives the state's 2022 allowances a value of $272.1 million. With declining numbers of allowances available to states over the course of implementation of the 111(d) rule through 2030, EVA projects the value of allowances will rise. In 2030, the EPA rule gives West Virginia allowances for 51,325,342 tons of CO_2 emissions. At EVA's projected 2030 allowance price of $9.43, the West Virginia 2030 allowances are valued at $484.0 million. From 2022 through 2030, the WVDEP will be distributing billions of dollars in value through the allocation of allowances. Different policy considerations in distribution of allowances free of charge versus selling them are identified below.

Distribution of Allowances Free of Charge

- The state is not increasing the cost of compliance for state electric generating unit owners by charging for allowances.

- Direct distribution of allowances to state EGU owners avoids the possibility that allowances sold at auction might be purchased by outsiders. Environmental groups could attain steeper reductions in emissions by acquiring allowances and holding them instead of allowing them to be used. Coal producers could buy them to bundle them with coal they are mining and selling out of state to try to assure that their coal remains marketable.

- The state can choose the basis for making the distribution, e.g., the available allowances can be distributed based on proportionate share of historic emissions, historic generation, heat input or some other basis.

- In distributing allowances, the state can choose a method that encourages certain activity, e.g., the two smallest generators covered by this rule, Grant Town and Morgantown Energy Associates (MEA), may be more vulnerable to the impacts from the 111(d) rule than larger generators. Both of them are providing an environmental benefit by burning waste coal that may be generating acid mine drainage. The alkaline ash they produce can also be used in AMD remediation. If the state wishes to assist smaller generators in compliance or encourage the environmental benefit they provide, the means of allocating allowances might be adjusted to favor them.

- MEA is the source of steam West Virginia University (WVU) uses for heating and hot water in about 80% of its buildings. WVU has no backup system or alternative at

88 Shand, J., Risch, C., et al. "EPA's Carbon Dioxide Rule for Existing Power Plants: Economic Impact Analysis of Potential State Plan Alternatives for West Virginia," March 2016 (CBER Report), p 41.

the present time and may face considerable difficulty if the impact of the 111(d) rule or other events caused a sudden interruption in the ability of MEA to produce steam. The means of allocating allowances could be adjusted to assure that an inability to obtain allowances does not cause this to happen.

Selling the Allowances

- If allowances are sold, the state is not giving billions of dollars in value to for-profit entities for free.

- Allowances have a value that the units receiving them will realize through their bids in the regional electricity markets, regardless of whether the allowances were acquired free of charge: "allowances have economic value given that they can be sold if not used and thus have opportunity cost associated with their use. Generators will normally add this cost to their other generation costs in their dispatch bid offers, just as they would reflect a fuel price change."[89] If the state sells allowances instead of giving them away, it can reap some of this value.

- There is no guarantee that, once given away to an electric generating unit's owner, an allowance will be used to support power production in West Virginia. Allowances can be transferred to affiliate companies elsewhere or simply sold in the market. If the state sells allowances, at least it receives some value for them before they may be used elsewhere.

- Revenue from sales of allowances could be used in a variety of ways:

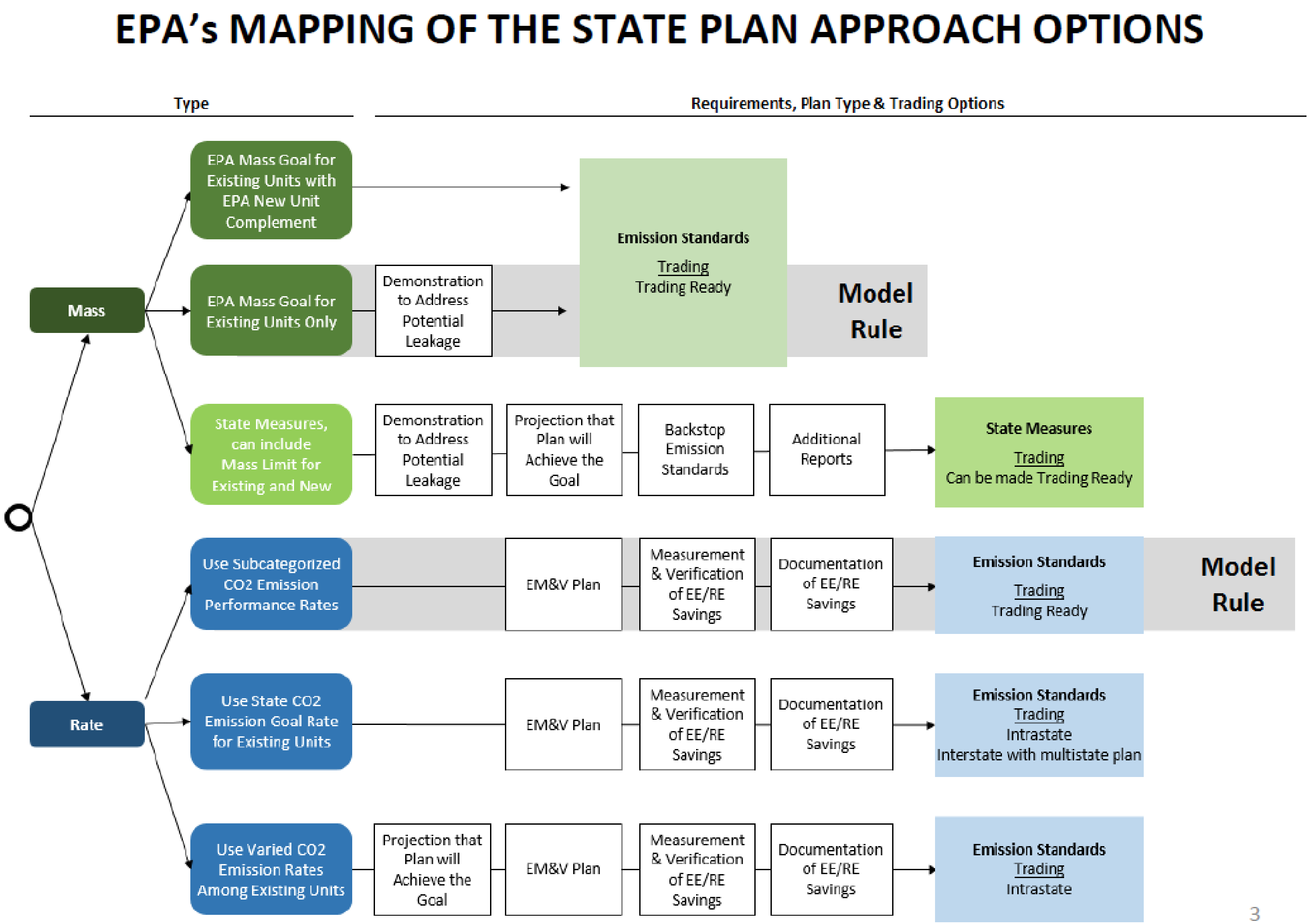
    - Provide rebates to West Virginia consumers to offset rising electricity prices – with a majority of West Virginia's power generation being sold outside the state, revenue from the allowances that support generation sold out of state sales could be used to subsidize instate electricity costs;
    - Subsidize installation of pollution control equipment at West Virginia EGU's to help prolong their ability to operate;
    - Fund job re-training programs for miners and electrical workers who might be displaced by the effects of the rule;
    - Help balance the state's budget; or
    - Any other purpose the Legislature desires.

2. State Plan Pathways

The figure below prepared by EPA provides a graphic illustration of the different state plan pathways described above. It may be helpful in visualizing the different issues that must be addressed and decision sequence for developing a state plan should one be necessary.

89 Franz Litz and Brian Murray. 2016. "Mass-Based Trading under the Clean Power Plan: Options for Allowance Allocation." NI WP 16-04. Durham, NC: Duke University, http://nicholasinstitute.duke.edu/publications, pp.8

Figure 19: EPA's Mapping of the State Plan Approach Options



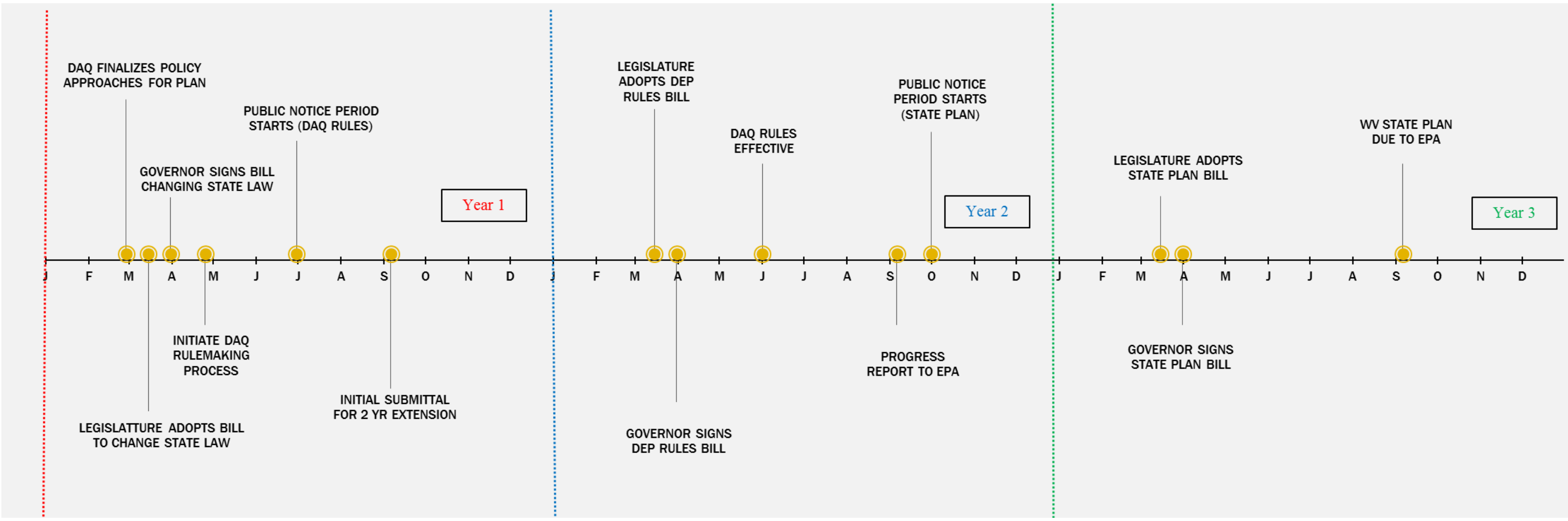
Source: Reproduced from EPA, modified to show compliance pathways only, https://www.epa.gov/sites/production/files/2015-08/documents/flow_chart_v6_aug5.pdf, Last Visited April 19, 2016

3. Timeline For Decision Making

To develop a state plan, legislative action to make the necessary changes to state law recommended above (see page 11) will be required in year one after a stay is lifted. Following these legislative changes, the WVDEP will have to promulgate rules establishing a state plan. To avoid losing a year in the rulemaking process, the WVDEP will need to have its proposal of the rules that will comprise the state plan written and ready to go in the rulemaking cycle that begins shortly after the legislative session in which the required legislative changes are made. In year two, WVDEP must obtain legislative approval of the state plan rules. In year three, the WVDEP must obtain legislative approval of its state plan submission to EPA as required by W.Va. Code § 22-5-20(b) in order to be able to submit a state plan. An important assumption in this timeline is that WVDEP does not need a specific legislative authorization to make a non-binding initial submittal to EPA in order to obtain a two year extension of time.

This three year timeline for all of the necessary legislative action on a state plan submission may exceed the time that will be available for state plan submission if the courts uphold the EPA rule, the stay of the rule is lifted and a new schedule for state plan submission comparable to the previous one is established. The previous schedule in the 111(d) rule provided thirty four and a half months between its publication in the Federal Register on October 23, 2015 and the September 6, 2018 final due date for a state plan submission, assuming the state obtained a two year extension.

Figure 20: Illustrative Timeline for West Virginia State Plan Development - Specific Dates to be Determined by the Courts



Year 1

Dates	Milestones
28-Feb	Policy Finalizers Policy Approaches for Plan
15-Mar	Legislature Adopts Bill to Change State Law
31-Mar	Governor Signs Bill Changing State Law
25-Apr	Initiate DAQ Rulemaking Process
30-Jun	Public Notice Period Starts (DAQ Rules)
6-Sep	Initial Submittal to EPA for a 2 yr. Extension

Year 2

Dates	Milestones
15-Mar	Legislature Adopts WVDEP Rules Bill
31-Mar	Governor Signs WVDEP Rules Bill
1-Jun	DAQ Rule Effective
6-Sep	Progress Report to EPA
1-Oct	Public Notice Period Starts (State Plan)

Year 3

Dates	Milestones
15-Mar	Legislature Adopts State Plan Bill
31-Mar	Governor Signs State Plan Bill
6-Sep	WV State Plan due to EPA

4. Future Developments that Will Inform State Plan Decisions

There are ongoing developments on at least three fronts that will inform decisions on a state plan that could not be taken into account in this comprehensive analysis. First, EPA continues to work on other rules and guidance that are ancillary to the 111(d) rule. Any developments on EPA's proposed federal plan rule and proposed model state rules will certainly supply useful information that should be considered in state plan decisions. It is not expected to finalize these rules until late summer. EPA also continues to work on the guidance that will provide greater detail and clarity on the CEIP and EM&V requirements that are both contemplated by its final 111(d) rule.

Second, different entities whose perspectives may be valuable continue to carry out analyses of the final 111(d) rule. NERC's final analysis of the impact of the 111(d) rule on reliability of the grid was expected to be released in late March 2016. This analysis may provide useful information when it is completed. PJM, the operator of the grid and wholesale power markets for this region of the country, is anticipated to complete its economic analysis of the 111(d) rule in June, 2016. PJM is also conducting an analysis of the impact of the 111(d) rule on the reliability of the grid. This analysis is expected to be released in July, 2016. These analyses by the operator of the grid for our area of the country will merit consideration in state plan development. Other entities continue to refine their modeling of the final 111(d) rule's impacts. With the time to consider these other analyses as a result of the Supreme Court's stay of the 111(d) rule, the state should be better equipped to make sound decisions on the various state plan options.

Third, the economics of decisions West Virginia might make will be affected by the pathways other states choose. Some other states are proceeding with state plan development notwithstanding the Supreme Court's stay. Other states have ceased state plan development but still maintain some level of communication regarding these issues. Continued dialog with as many other states as possible will keep West Virginia well informed and in a position to make the best decision possible should development of a state plan be required.

Appendix