THE STATE OF WYOMING

GOVERNOR
Matthew H. Mead

Public Service Commission

COMMISSIONERS
Alan B. Minier, Chairman
William F. Russell, Deputy Chairman
Kara Brighton, Commissioner

SECRETARY AND CHIEF COUNSEL
Christopher Petrie
COMMISSION ADMINISTRATOR
Darrell Zlomke

November 21, 2014
PSC LETTER NUMBER 14-178

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Docket ID No. EPA-HQ-OAR-2013-0602. Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Dear Administrator McCarthy:

The Wyoming Public Service Commission appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA or Agency) proposed rule to limit carbon dioxide emissions from existing power plants (Proposal). Our comment is principally focused on Wyoming's emission performance goal. We are mindful of EPA's position that it will not adjust a state's goal "unless the state also demonstrates that it could not get additional reductions from application of" other building blocks. Federal Register notice, p. 90. Accordingly, it is our intention to demonstrate that all four building blocks overestimate what is technically feasible, and/or entail costs significantly higher than those projected by EPA. It follows that, with respect to each of the building blocks, "the application of the other building blocks would not result in greater emission reductions than are reflected in EPA's quantification for [Wyoming]." Id., p. 91. We also disagree that "the building blocks are based on a reasonable degree of stringency." Id. Collectively, the blocks are far too stringent.

We will comment in passing on some of the specific issues for which EPA sought comment. These issues will principally relate to Wyoming's goal.

Block 1 – Heat Rate Improvements

The goal for heat rate reduction is too high. We believe that 2% is a more realistic challenge for the Wyoming coal-fired EGU fleet. However, there is a threshold issue which becomes apparent once the

Hansen Building • 2515 Warren Avenue • Suite 300 • Cheyenne, Wyoming 82002
Ph. (307) 777-7427 • Fax (307) 777-5700 •TTY (307) 777-5723 • www.psc.state.wy.us

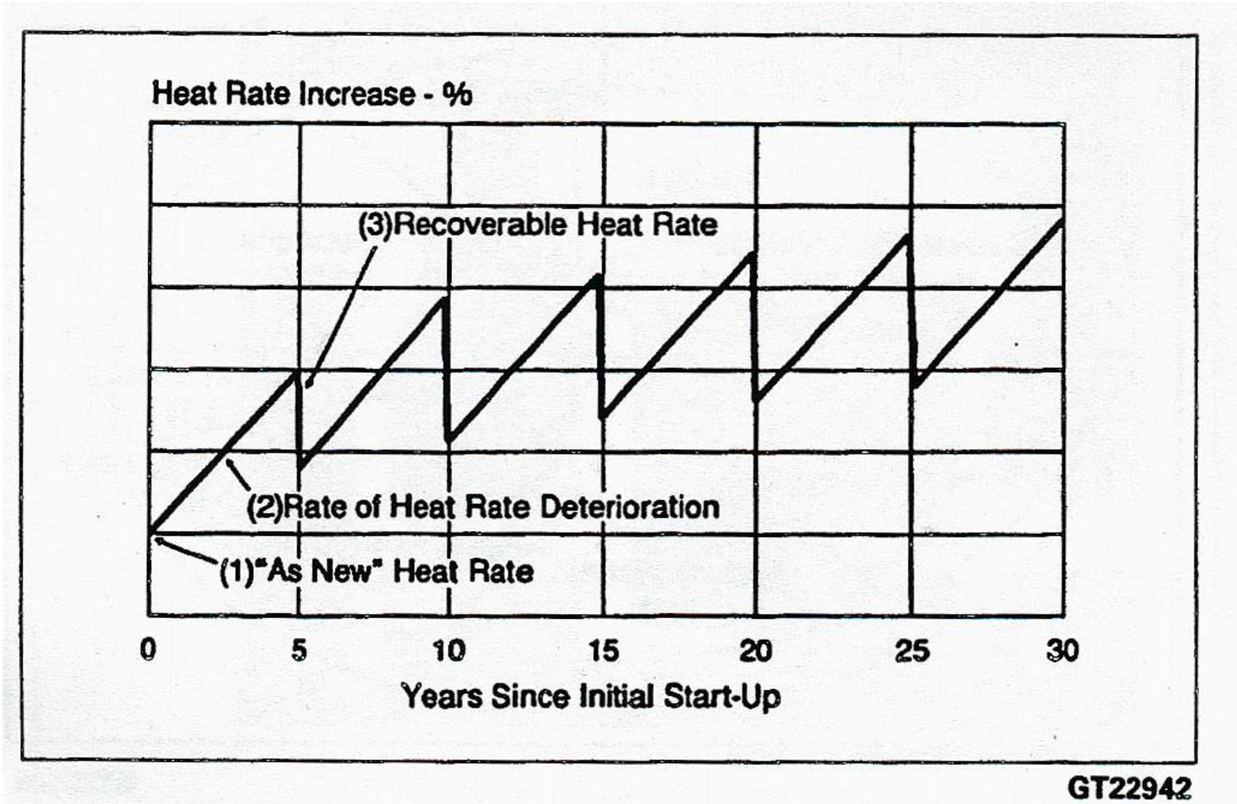
other three blocks are considered. EPA's BSER works at cross-purposes with itself. EPA intends success in Blocks 2, 3, and 4 to displace coal-fired generation, which will make existing plants less efficient.

We know EPA intends this displacement from express statements in the GHG Abatement Measures TSD ("TSD") and from EPA's spreadsheets. The effect of substituting gas-fired generation under Block 2 is depicted in Steps 3a and 3b of the EPA spreadsheet of calculations for state targets; as an extreme example, Block 2 re-dispatch eliminates Arizona's 24 million megawatt hours of 2012 coal generation entirely. EPA's explanation of Block 3 calls for reducing carbon dioxide emissions from EGUs "through the substitution of electricity generated from renewable sources." TSD, p. 4-1. The explanation of Block 4 describes energy efficiency as "an abatement measure" for reducing emissions from EGUs. TSD, p. 5-1.

EPA intends the rate of this displacement to increase during the glide path compliance period running through 2029. EPA energy efficiency modeling depicts a .97% annual average growth rate for Wyoming intrastate sales of megawatt hours. Data File: GHG Abatement – Scenario 1 (XLS). Blocks 3 and 4 are depicted as growing far faster than 1%. The mathematical result is an escalating reduction in coal-fired generation.

Displacement of coal-fired generation means that existing plants will be operated at reduced capacity. While all EGUs are not alike, EPA has stated what this means: "Coal-fired units are designed to operate most efficiently at full capacity. As a unit drops below this level, in general, heat rate will increase." TSD, p. 2-23. In contrast, the 4% best practices piece of EPA's target assumes a static operating environment: "Reducing heat rate variability will generally also improve heat rate performance, *other factors held equal*." TSD, p. 2-34. For Wyoming, a state with ample coal-fired generation, this is not a minor inconsistency. The state cannot possibly meet its target without pursuing Blocks 1, 2, 3, and 4, and cannot meet Block 1 if it succeeds with the other three Blocks.

EPA has also assumed that projects to improve heat rate, once complete, can be sustained through 2029, which is improbable. One example is replacement of original turbine steam path components with state of the art technology (turbine replacement). The Sargent & Lundy report identifies this measure as the one which offers the greatest potential benefit, in the range of 100 to 300 Btu/kWh. TSD, p. 2-8. A General Electric technical document, "Steam Turbine Sustained Efficiency," GER-37 50C, includes a figure depicting the typical progression of heat rates following installation. Best results will be achieved when the turbine is brand new and must meet manufacturer specifications on commissioning. Heat rate rises thereafter with use, with partial recovery of the original rate after first overhaul. The pattern recurs with subsequent use and overhaul, each time recovering only partially from the preceding overhaul. Here is the figure:



The illustrated five-year cycle is not the same for all plants. For practical and economic reasons, turbine overhauls are integrated into unit major maintenance overhaul cycles and return only a fraction of the heat rate improvement that a turbine replacement project (i.e., new technology) does. As an example, the four units at PacifiCorp's Jim Bridger EGU undergo plant-wide major maintenance overhauls in four year cycles, with turbine overhauls being made at 8 or 12 year intervals, depending on turbine performance and the economics of the specific measures.

Turbine replacement projects for individual units of the type that Sargent & Lundy refers to are justified on a case by case basis, as they entail extended planning, detailed design, long lead-time component manufacture, and significant expenditures. PacifiCorp completed turbine steam path replacement projects at Jim Bridger Units 1 and 2 in 2010 and 2013, respectively. Turbine replacement projects at Units 3 and 4 are not currently planned. It is worthwhile noting that in 2015 and 2016, Units 3 and 4 are being retrofitted with SCRs for regional haze compliance.

The problem of heat rate degradation during the fifteen year cycle of the proposed rule is in the very nature of operating a coal-fired EGU. It is a problem EPA seems to have either overlooked or ignored.

Although advocating that EPA recalculate Wyoming's compliance goal using a heat rate improvement of 2% or less, we also suggest that EPA allow states to assess measurable heat rate improvements available to the plants in the Wyoming fleet and then to develop a composite compliance goal. The State could designate the measurement period for each unit at each plant. Maintaining flexibility in timing the measurement of best effort is a practical necessity. For example, turbines at Laramie River Station were replaced before those at Jim Bridger, which means that the benefits of turbine replacement at the two plants will be on a different cycle. A broad window should also be available to accommodate existing overhaul schedules which tend to avoid making more than one unit unavailable at a time, and to accommodate compliance with environmental upgrades.

In response to a request for comment in the Notice of Data Availability (NODA) of October 27, 2014, we consider a phase-in of Block 1 to be essential. In plants with multiple units, the cumulative stress to the grid may be unmanageable if all units are taken off line at once, particularly if plants at different locations are attempting to comply at the same time (a more detailed discussion of the application of the numerous Sargent & Lundy technologies to Wyoming EGUs follows below). Further, utilities may not have the managerial capacity to take on multiple upgrades and complex environmental compliance projects at the same time.

There may also be insufficient contracting capacity nationally and regionally to undertake too much work at once; and there can be no question that costs escalate with expedited schedules, or when contracting capacity is strained. Recent capital projects in Wyoming have had the advantage of occurring when pricing has been restrained by the financial shock of 2008 and slow growth since then, cushioning ratepayers from the effect of MATS and regional haze compliance. This Commission has also observed the ratepayer benefits of being patient with implementation. We nonetheless do not claim to have a regional or national perspective that would allow us to advise EPA on the duration or design of a phase-in period. However, an added concern – one we anticipate has already been raised by other commenters – is the prospect of triggering time consuming NSR/PSD review for major and minor modifications.

In an effort to determine what a reasonable one-time heat rate improvement for the State's coal-fired EGU fleet might be, i.e., setting aside the question of whether any such improvements could be sustained, the Wyoming Public Service Commission and the Wyoming Department of Environmental Quality consulted with the operators of Wyoming's coal fleet. We asked these operators to ascertain what heat rate improvements were feasible, and more specifically, to review the applicability of available technologies listed by Sargent & Lundy – all of them, not just the technologies highlighted by EPA. We viewed the technologies in that report as an exhaustive list covering the entire range of possibilities for EPA's 6% improvement, through both best practices (4%) and equipment upgrades (2%). The TSD adopted a more limited focus on technologies of interest as best practices and equipment upgrades. TSD, pp. 2-5 to 2-11, 2-33. The Sargent & Lundy report identified the potential ranges of improvements, expressed in Btu/kWh and broken out by 200 MW, 500 MW, and 900 MW parameters. The list of thirteen technologies and potential improvements EPA singled out, with lowest to highest Btu/kWh regardless of plant size, was:

Best Practices S&L Reference	Subject Matter	Low Value	High Value
2.3	neural network	0	150
2.4	intelligent soot blowers	30	150
2.5.1	air heater and duct leakage control	10	40
3.3	condenser cleaning	30	70
3.4	boiler feed pump rebuild	25	50
5.1	modify flue gas desulfurization system	0	50
5.2	electrostatic precipitator modification	0	5
5.3	SCR system modification	0	10
6.3	cooling tower advanced packing	0	70
	Best practices total	**95**	**595**
Upgrades			
2.2	economizer replacement	50	100
2.5.2	acid dew point control	50	120
3.1	turbine overhaul	100	300
4.2	combined VFD and fan	10	150
	Upgrades total	**210**	**670**
	Combined total	305	1265

We realize that the listed range of values in this chart, 305 to 1265, is not the same as the range of 415 to 1205 which appears in the Federal Register Notice, p. 52, but cannot account precisely for EPA's tally and have referred directly from the specified sections of Sargent & Lundy.

Taking everything into account, we believe a statewide improvement of 2% is the best that could be achieved. Because the operators reviewed specific measures in the context of specific plants, they could make specific judgments about whether costs aligned with benefits. This information is superior to the broad ranges on which EPA has premised its proposed rule.

PacifiCorp concluded that an overall improvement of 2.8% for its fleet might be economically practicable and technically feasible over a period of years, but this number depends heavily on turbine upgrades to Units 3 and 4 at Jim Bridger. Otherwise, PacifiCorp identified improvements ranging from .3% to 2.5% for each unit, subject to offsetting reductions for environmental compliance upgrades.

Black Hills contracted with Black & Veatch for a report concluding that net unit heat rate improvements of 1.8% were feasible for each unit of its four plants.

Basin Electric estimated improvements of less than 2% were possible at Laramie River Station, subject to a degradation of .5 to 1.5% related to SCR installation, a potential modification now in dispute under EPA's regional haze regulations. Basin Electric estimates the potential for the much newer Dry Fork Station to be no more than 1%.

Aside from the threshold issues mentioned above, what reasons account for the difference between EPA's 6% and our estimate of 2%?

The first reason is EPA's unorthodox approach to cost estimates. The Wyoming operators accepted Sargent & Lundy's recommendation that they conduct "site-specific evaluations and cost analyses based on actual market conditions for any and all required equipment, material, and labor at the time of the project." S&L report, p. 1-3. In other words, the Wyoming operators considered fuel costs as they normally would and do, together with other features of a normal project evaluation. The most common reason for PacifiCorp and Black Hills to reject a proposed Sargent & Lundy measure was that it was not economic.

EPA gives a nod to conventional cost evaluation by computing a supposed breakeven cost for heat rate improvement measures, TSD, p. 2-37 to 2-38, but this is only a nod. EPA argues that the carrying cost of heat rate improvements can largely be met through fuel cost savings, and what is unmet should be small enough for the utility to absorb. EPA illustrates its argument mathematically with calculations in the text associated with footnote 119 to the Federal Register notice. The key is EPA's calculation and use of a national average coal price of $2.62 per MMBtu. Footnote 119 and TSD, p. 2-39. Using this average price, and assuming a capital cost rate of 14.3%, EPA calculates that its 6% heat rate improvement would produce fuel savings of $11.20 per kW-year for a capital investment of $100 per kW, leaving "approximately $3.10" per kW-year not covered by fuel costs. Federal Register notice, p. 52. By a further calculation, EPA concludes that the average cost of carbon dioxide reductions not covered by fuel cost savings would be approximately $7.75 per metric ton. Id.

EPA's approach heavily discriminates against western utilities, as EPA's own modeling suggests. Consider these results for 2016 coal prices from EPA's Integrated Planning Model, EPA Base Case v.5.13:

Mine Mouth Coal Prices	
Region	*2011 $/MMBtu*
Appalachia	2.38
Imports	3.39
Interior	2.20
Waste Coal	1.38
West	**0.91**
National (weighted average of regions)	1.63

It immediately becomes apparent that a western mine mouth EGU has far lower fuel costs than EPA assumes. This has a dramatic impact on EPA's calculations, an impact that EPA cannot gloss over by recognizing that its simplified cost analysis "will represent costs for some EGUs better than others because of differences in EGUs' individual circumstances." Federal Register notice, p. 52.

When we substitute an actual 2012 fuel cost for the Wyodak mine from FERC Form 1, $0.804 per MMBtu, into EPA's calculation, fuel costs cover only $3.44 of the $14.30 carrying cost, leaving $10.86 not recovered. EPA's unrecovered cost of $7.75 per metric ton rises to $27.13 per ton, or an increase of three and a half times EPA's value. In the chart below, using the calculation explained in footnote 119 of the Federal Register notice, p. 194, the fuel cost per kW-year is the product of the six items which precede it. The carrying cost reflects EPA's assumed capital cost rate, referenced above. The 0.4 metric tons of reduced emissions are calculated by EPA, and the price of a metric ton of carbon dioxide is the result of dividing unrecovered cost by metric tons of reduced emissions as explained in the Federal Register Notice, p. 52. The complete calculation is:

Btu/kWh	10450	10450
Hours/year	8760	8760
Utilization	0.78	0.78
$ per MMBtu	$2.62	**$0.804**
Heat rate improvement	0.06	0.06
MMBtu/Btu	0.000001	0.000001
Fuel cost $ per kW-year	$11.22	**$3.44**
$ carrying cost	$14.30	$14.30
$ not recovered from fuel	$3.08	**$10.86**
reduced CO_2 emissions	0.40	0.40
$ value of metric ton of CO_2	$7.69	**$27.13**

This irrationally discriminates against western mine mouth EGUs. It contradicts EPA's expectation that "the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings." Federal Register notice, p. 52.

This is more than just another statistic. The design of every generating unit was originally based on a balance of such factors as the required output, available fuel quality and cost, site conditions, and water supply. Mine mouth EGUs located near Gillette, Wyoming, depended on low cost fuel to offset the expense of air cooling. Measures which undermine an original cost advantage undermine the economics of the entire plant. To a greater or lesser degree, EPA's economic analysis undermines the economics of every plant with a fuel cost more favorable than EPA's calculated average.

The operation of an EGU normally accounts for similarly embedded costs which are constantly considered as part of a balance. The operation of an EGU typically is based on optimizing unit availability, heat rate, and expenditures (for operations and maintenance and for capital investment) to produce the lowest net power cost. EPA should regard with suspicion any explanation of substantial change which ignores this balance. For example, the average heat rate can be improved by increasing the frequency of turbine overhauls, but it is always a question whether the cost of doing so can be supported, and particularly doubtful that, for the diverse national fleet, fuel savings alone can cover that cost. EPA should question the premise that it should interfere with established economically driven operating practices without a clear identification of benefits.

EPA has also ignored the problem that every aging plant eventually reaches the point at which costly environmental compliance upgrades or equipment investments cannot be recovered during the remaining useful life of the plant. Not every plant is ready for immediate retirement, although EPA notes that, of its study population of 884 plants, TSD, p. 2-16, 233 EGUs "have announced they will retire before 2016." TSD, p. 2-35. We previously advised EPA that premature closures would have significant financial consequences for Wyoming ratepayers. (Letter to Janet McCabe, December 16, 2013, posted at psc.state.wy.us, under "Hot Topics"). EPA has also recognized the problem of remaining useful life in the regional haze context. In a final determination dated January 10, 2014, EPA provided the option of either closing Dave Johnston Unit 3 in 2027, when scheduled to be fully depreciated, or installing SCRs within five years. Here is a list of the Wyoming plants subject to Section 111(d), with their December 2013 full depreciation dates and their operators[1]:

1 On January 30, 2014, EPA promulgated a federal implementation plan requiring Basin Electric to install selective catalytic reduction technology as BART at each of the three units at the Laramie River Station. This decision was based in significant part on NO_x reductions EPA calculated could be achieved over a twenty year remaining life of the units, making the capital

Plant	Retirement	Operator
Dave Johnston	2027	PacifiCorp
Naughton	2029	PacifiCorp
Jim Bridger	2037	PacifiCorp
Wyodak	2039	PacifiCorp
Laramie River Station	2040	Basin Electric
Dry Fork Station	2044	Basin Electric
Neil Simpson II	2045	Black Hills
Wygen 1	2048	Black Hills
Wygen 2	2053	Black Hills
Wygen III	2060	Black Hills

Finally, EPA may wish to consider whether the studies it reviewed, TSD, Table 2-3, were too narrowly focused to provide an adequate perspective on setting a target heat rate, particularly with respect to the economics of doing so. In November 2012 the Union of Concerned Scientists published a paper entitled, "Ripe for Retirement: The Case for Closing America's Costliest Coal Plants." That study concluded with a high estimate of 353 plants located in thirty-nine states that should be closed. Not one of those plants was located in Wyoming.

The cure for EPA's approach to cost estimates is to eliminate reliance on the national average and to embrace standard cost evaluation practices. If elaborate calculations from an extensive dataset must be made, they should include more accurate fuel cost data, some of which is available from the FERC Form 1.

The second reason for the disparity between EPA's 6% estimate and our 2% estimate is EPA's flawed rationale for the 4% best practices improvement. EPA's logic rests on improvements to the national fleet of coal-fired EGUs, rather than the much smaller fleet that will be regulated by each state. The smaller state fleet does not share the same characteristics as the national fleet. EPA nonetheless reasons that "if each unit achieved heat rate performance equal to its best three-year moving average [out of eleven years of data], the study population as a whole would post a 3.9% heat rate improvement….EPA believes that the minimum three-year moving average heat rate is a reasonable target for the improvement potential from applying best practices." TSD, p. 2-34. While "[t]he heat rate improvement for the study population is derived from the performance of each individual EGU as compared to its own record," TSD, p. 2-31, the proposed rule does not consider each individual plant or the statewide fleet of plants, but instead computes a single national target based on a single national average.

This creates a severe prejudice for a state with a fleet of EGUs largely or exclusively in the first and second quartiles. If the plants are already within a limited range of variability, EPA cannot reasonably require a percentage improvement based on the entire national fleet which, by definition, is characterized by substantially greater variability. At the very least, EPA's state targets should begin with disclosure of

---

cost of these newly imposed technologies reasonable in EPA's view. The effective date for these control technologies, if affirmed on appeal, begins in approximately 2020, demonstrating that EPA has already determined that Basin Electric should be committed to enormous capital expenditures based on operations until at least 2040 for Laramie River Station. See, 79 Fed. Reg. 5032 (Jan. 30, 2014). Similar logic should apply to PacifiCorp investments in the same technology, but for the sake of consistency with our earlier letter and with an illustrative purpose in mind, we have only changed Laramie River Station.

the results of its calculations for individual plants or units, including the three-year moving average of each plant or unit, then rank order each plant or unit. Those results should be provided with sufficient context to consider what a fair target for individual plants or units might be, and with that, what a fair composite target for a state might be. EPA's approach to Block 1, which was to simply adjust the combined state-level emissions rate for all state coal-fired EGUs by 6%, is arbitrary.

With specific information about where these plants fall on EPA's continuum, the state would be in a position to address specific issues that might warrant adjustment in a proposed heat rate for an EGU, and for the state fleet as a whole. The EPA should be considering just such a process. The consequences for the state and the utility are too dire to rush to judgment on an erroneous target, as we will discuss in further detail below in the conclusion section of these comments.

We also question the notion that every EGU is in a position to achieve its best three year performance (out of eleven years) through the adoption of best practices. It is common knowledge in the industry that average capacity factors of plants and fleets decline with time, and the decline becomes more marked in the later years of the EGU's life. *E.g.*, Carl Bauer, presentation to Wyoming Infrastructure Authority, October 17, 2014, slide 9; Dr. Robert Peltier, Predicting U.S. Coal Plant Retirements, *Power*, May 1, 2011. Table 2-5 of the TSD directly reflects on this issue, showing reported annual capacity factors ranging from highs of 70-71% in 2004-2008 which declined to a low of 53% in 2012. EPA speculates that decline may be due to the economy in general or to competing sources of electricity, but does not meaningfully address the effect of aging. TSD, p. 2-20.

More important, EPA has not made any effort to understand the broader set of circumstances which have changed over eleven years, and which may prevent an EGU from returning to earlier heat rates. Examples from the Commission's experience readily come to mind. An EGU is served by a captive coal resource of declining quality. A base load coal-fired EGU is regularly backed down to accommodate and support radically increased wind generation. The EGU has been retrofitted to meet more stringent compliance standards. None of these causes will be found in the 61,848,580 hourly records found in EPA's datasets, even though effects may be reflected there.

A third reason for the disparity between EPA's 6% estimate and our 2% estimate is that EPA overstates the applicability of Sargent & Lundy technologies. EPA concluded a 2% improvement related to equipment upgrades was appropriate, having reduced a 4% estimate "because some EGUs may have already implemented some of these upgrades." Federal Register notice, p. 51. "Implementation" is a grossly insufficient explanation of why the Sargent & Lundy technologies may or may not apply. We first report on the four equipment upgrades, and then turn to the nine best practices. Where there has been agreement that a measure is appropriate, it has been included in our 2% estimate.

As noted above, only two turbines (Sargent & Lundy, Section 3.1, hereafter S&L 3.1) in the Wyoming fleet may satisfy the economic criterion for replacement between now and 2020, and neither is currently planned. In all other cases, the plants are new; the turbines have recently been replaced; or the plant is too old to replace or refurbish the turbines and recover costs. The replacement of those two turbines – again, the highest impact item on the Sargent & Lundy list – has already been accounted for in our estimate.

The installation of variable frequency drive (VFD) fans (S&L 4.2) is generally uneconomic unless the units are being operated at partial load, and most of the PacifiCorp units are base load. The only identified PacifiCorp opportunity is Naughton Unit 3 in 2018, when that unit will be converted to gas firing and hence used for partial load. Modifications to the induced draft fans at the four Black Hills units are included in our 2% estimate.

Regarding economizer replacement (S&L 2.2), the Black Hills plants are generally too new for the problem described by Sargent & Lundy to apply, and the issue has been deferred for a more nuanced engineering review. At Wyodak, the plant needs the heat for winter operations, so the modification is not suitable. At Naughton 1 and 2, the modification would not be economic within the plant's remaining book life ending 2029. Naughton 3 will be converted to gas in 2018. At Dave Johnston 1 and 2, the change would not yield substantial benefits due to the quality of coal being burned, and replacement is not necessary or appropriate due to the operation of new emissions control equipment. The S&L replacement already occurred at Dave Johnston 4 in 2009. Dave Johnston 3 is considering the improvement based on a 2014 study which did not find direct heat rate benefit, but indicated indirect potential for improvement by addressing existing problems with plugging and fouling. The improvement is under consideration but not budgeted. Modification is planned for the four units of Jim Bridger from 2015 through 2018, with an anticipated improvement of 21 Btu/kWh at each unit, that is, less than the range anticipated by S&L.

PacifiCorp generally characterized the acid dew point control (S&L 2.5.2) issue by reference to S&L's suggested remedy, which focuses on lowering outlet temperature by air heater modifications. For Dave Johnston 3 and 4, and Wyodak, the modification is not feasible because the plant needs existing exit temperatures to operate its scrubber during winter operations. For Dave Johnston 1 and 2, the change was uneconomical due to extensive changes that would be required for existing structures. Heaters have already been implemented in Bridger Unit 4, and are scheduled for the other three units from 2019 to 2022, during annual scheduled maintenance of individual units. Naughton Units 1 and 2, and the four Black Hills plants, are already operated near the acid dew point.

Black Hills and PacifiCorp both characterize the neural network issue (S&L 2.3) as a matter of boiler controls. Black Hills agrees that a potential modification could be made for an improvement of 8 Btu/kWh over its four plants, i.e., in the low end of the range anticipated by S&L. PacifiCorp has planned neural network upgrades for the four units of Jim Bridger from 2019 through 2022, and is contemplating further upgrades from 2023 through 2026. No change is possible at Dave Johnston 1 and 2 because these units do not utilize a distributive control system, so a complete change of the control system would be required, which is not economical. PacifiCorp recognizes the potential for a neural network improvement on Dave Johnston Units 3 and 4, at Naughton Units 1, 2, and 3, and at Wyodak, although the modifications are not currently planned.

Black Hills agrees to the potential for intelligent soot blowers (S&L 2.4) at all four of its plants, with anticipated savings of 35 to 41 Btu/kWh (the lower end of the S&L range). PacifiCorp has scheduled this improvement at Wyodak for 2022. At Naughton 1, the boiler is cleaned using existing procedures and there is no room for improvement; similarly, at Dave Johnston 1 and 2 there is not a significant problem. Intelligent soot blowers are scheduled for installation in Dave Johnston 3 in 2018 and Dave Johnston 4 in 2016. Intelligent soot blowers were installed in all four units of Jim Bridger in 2006. Naughton 2 installed a soot blower in 2009 which was re-commissioned in 2013. Naughton 3 will be converted to gas in 2018.

As a measure related to S&L's air heater and duct leakage control issue (S&L 2.5.1), Black Hills recognizes the potential for an air heater sealing system upgrade, at a collective improvement of 11

Btu/kWh for its four units, once more toward the lower end of the S&L range. PacifiCorp has scheduled the installation of duplex seals on the four units of Dave Johnston from 2015 through 2018. PacifiCorp has upgraded the seals at Naughton 1, but Naughton 2 and 3 were designed for low leakage and have been maintained at that level. Due to the design of air cooled Wyodak, no possible modification is economical. Pertinent modifications to Jim Bridger's four units are scheduled from 2015 through 2018.

PacifiCorp implemented modifications to Wyodak's condenser (S&L 3.3) in 2011. Black Hills considered adding five fans to its air cooled configuration, but found that doing so did not improve the heat rate. PacifiCorp determined the condensers at Dave Johnston 1 and 2 were performing well, so no modifications were warranted. It also determined that fouling in Dave Johnston 3 had been reduced by introducing stainless steel tubing in 1990, and concluded further changes were not economical. In a similar situation at Dave Johnston 4, modified in 1987, PacifiCorp may clean more frequently, i.e., quarterly rather than biannually. PacifiCorp replaced the original copper tubes of the four Jim Bridger units with titanium from 1996 through 1999, and no further changes are contemplated. Changes at Naughton 1 and 2 are not economical in view of its 2029 retirement date, and Naughton 3 will be converted to gas in 2018.

PacifiCorp has concluded that S&L's proposed boiler feed pump rebuild (S&L 3.4) would not be economical at the Dave Johnston units due to the low value of the potential heat rate improvement. They concluded the same for the four units of Jim Bridger. PacifiCorp notes that boiler pump overhaul frequency is already optimized at Naughton by reliance on flow performance testing. Both boiler feed pumps are already overhauled at Wyodak. Somewhat in contrast, Black Hills identified an opportunity to add variable speed couplings that would reduce boiler feed pump auxiliary power consumption.

None of the flue gas desulfurization system modifications (S&L 5.1) are applicable to the four Black Hills plants or Wyodak, all of which are air cooled. None of the modifications are applicable at the Dave Johnston units, which do not have the supposed scrubber. Gas distribution devices have been implemented at Dave Johnston 3 and 4, and Naughton 1 and 2. The scrubber at Naughton 1 and 2 is new and properly sized. Naughton 3 will be converted to gas in 2018. The proposed changes to the Jim Bridger are either inapplicable as the units are designed (removal of a non-venturi throat or shutoff spray level) or uneconomical (gas distribution devices).

The electrostatic precipitator modification (S&L 5.2) issue does not apply to Wyodak or the four Black Hills plants as they are designed. PacifiCorp has scheduled new ESP controls for the four units of Jim Bridger from 2014 through 2017, and new ESP transformers and reactors for 2018 through 2012, but no heat rate improvement is expected. Modifications to Dave Johnston Units 1 and 2 have already been implemented, and are inapplicable to Dave Johnston Units 3 and 4, which are equipped with bag houses. Modifications to Naughton Units 1 and 2 are uneconomic, since they are calculated to yield a maximum improvement of only 5 Btu/kWh, even though this is the upper end of the range anticipated by S&L.

PacifiCorp expects deterioration in heat rate, not improvement, with the mandated installation SCRs (S&L 5.3) on Jim Bridger Units 3 and 4 in 2015 and 2016, and Units 1 and 2 in 2021 and 2022, all related to regional haze compliance. The modification does not apply to any of the Naughton, Dave Johnston or Wyodak units, since none are equipped with an SCR. Black Hills also concluded this modification did not apply.

S&L's cooling tower advanced packing (S&L 6.3) issue does not apply to Wyodak or the four Black Hills plants, all of which are air cooled. Modifications have been made and are in progress at Jim Bridger. PacifiCorp replaced the Unit 1 cooling tower in 2014, and installed VFDs in 2006; replaced the Unit 2 cooling tower in 2013, and installed VFDs in 2005; has scheduled the replacement of the Unit 3 cooling tower in 2015, and installed VFDs in 2005; and has scheduled replacement of the Unit 4 cooling tower in 2016, and replaced the Unit 4 cooling tower and VFDs in 2004. PacifiCorp modified Naughton Unit 1 prior to 2012, but does not plan modifications to Unit 2 or Unit 3 due to the pending retirement date of the plant. The pertinent modifications have already been implemented at all Dave Johnston units.

After this review of the thirteen S&L measures, we agree with EPA's observation that, "The existing EGU design and other site-specific factors may prevent the technical feasibility of using a given technology." TSD, p. 2-6. We urge the EPA to give more consideration to the implications of that fact, and to further consider its list of factors affecting EGU efficiency at a given facility. TSD, p. 2-4 to 2-5. EPA's heavy reliance on its existing datasets – the 61,848,580 hourly records for 884 EGUs -- seems to have distracted its attention from the virtual absence of data that would provide more conventional insight into what modifications are possible and valuable as a practical matter.

EPA has noted significant gaps in its data. "In this analysis, units are not categorized by unit specific design characteristics or fuel because: (1) EGU-specific detailed design information on all factors that influence heat rate is not available, and (2) certain design characteristics are not easily categorized (e.g., EGUs use a large range of steam conditions)." TSD, p. 2-19. "The EPA does not have sufficient site specific information to accurately estimate what percentage of the fleet has adopted various HRI methods, nor how effectively, and is not aware of any other investigator having sufficient information." TSD, p. 2-36. EPA should be concerned that a large but incomplete data set can and will yield conclusions that are simply wrong.

What EPA has done resembles a mass real estate appraisal without having a sufficient universe of the supporting data that drive individual results, which are the purpose of conducting a mass appraisal. No assessor would use a mass appraisal approach to derive an average value for all of the real property in a city, and tax all of that property as if it were worth that average value. An average does not always achieve a fair or a wise result, and it will not do so if employed as EPA proposes.

EPA should also consider whether its conclusion that "a U.S. coal-fired EGU fleet-wide improvement ranging from 9% to 15% is *theoretically* possible," TSD, p. 2-13, is a firm ground for the target it proposes. For the Wyoming coal fleet, we see no evidence of an ample harvest of heat rate improvements that the utility industry has overlooked or ignored. Many of the S&L recommendations do not apply to Wyoming EGUs as they are designed and/or operated. Some problems identified by S&L do not in fact occur. In many instances, the improvement value associated with the measure is at the low end of S&L's scale. In most instances, the actual implementation of these measures is most wisely done consistent with a maintenance schedule that supports system reliability. It is only sensible, and more fair, to consider the practical realities of the state fleet when setting a binding target. It is not sensible, and not fair, to set a binding target based on averages for the national fleet; this is a large and diverse country, a reality which should be the foundation of any lasting effort to regulate greenhouse gas emissions from existing EGUs.

Finally, we urge EPA to consider whether it should re-conceive Block 1 from the bottom up, with an emphasis on engaging the utility industry to articulate a practical technical objective, and to arrive at a more complete understanding of how that objective can be achieved without undue detriment to ratepayers. Specifically, EPA may wish to consider whether it is desirable to micromanage plant operations by insisting on immediate implementation of the technologies assessed by Sargent & Lundy that have already been scheduled reasonably and with care. Accelerated schedules will increase costs to be passed on to ratepayers, and will likely strain the capacity of the utility industry for no compelling purpose, particularly if EPA anticipates continued displacement of coal fired generation by action of the other three Blocks. With so many moving parts in play, EPA should create a mechanism to reconsider the practical value of the portion of the overall target related to Block 1, once experience provides more insight into whether it can or will remain desirable as currently conceived.

Block 2 – Dispatch Changes

EPA has mistakenly identified the Under Construction Capacity of the Cheyenne Prairie Generating Station as 220 MW. As constructed and put into operation on October 1, 2014, the net output of the combined cycle (NGCC) unit is 95 MW. 95 MW is the net output adjudicated and authorized for inclusion in rate base in proceedings recently concluded before this Commission. Although the name plate capacity of the unit is 100 MW, its capacity has been adjusted to account for the fact that it will be operated at over 6000 feet above sea level, as both elevation and air density affect output. Wyoming's target should be corrected to accurately reflect the 95MW net output.

In its October 27 Notice of Data Availability, EPA solicited comment on whether to establish some minimum value as a floor for the purposes of Block 2, and comment on what such a value might be, specifically suggesting the lower quartile value of 12%. The NODA explained that the argument for doing so is:

> ….this expanded approach would be more consistent with historic NGCC deployment, better reflect growing geographic availability of natural gas supply, contribute to the expanded fuel diversity in states that currently have relatively little NGCC capacity, and offer more cost-effective emissions reductions.

NODA, III.B.1. The ostensible concern is for "significant disparities in state goals between those states with little or no NGCC generating capacity and those with significant amounts of NGCC capacity not currently being used fully." Id.

Wyoming is a state with little NGCC generating capacity. It is not clear, however, why this disparity should be an administrative priority. As a recent article in Public Utilities Fortnightly points out, success with Blocks 3 and 4 "would require much higher CO_2 prices than $50/ton" in Wyoming. Bellman, "EPA's Clean Power Plan: An Unequal Burden," October 2014. This is plainly a significant disparity as well. If the unstated premise of the Block 2 minimum is that EPA has failed to punish Wyoming enough, we respectfully disagree.

As we have previously explained to EPA in the letter dated December 16, 2013, the premature closure of coal fired EGUs will likely result in the construction of new NGCC capacity to meet existing demand, all to the detriment of ratepayers. What is not so clear is whether this new NGCC capacity would or should be constructed in Wyoming. The only natural gas conversion presently scheduled in Wyoming, the Naughton 3 unit in 2018, will simply fire the existing boiler with gas rather than coal. It is not a replacement of the existing unit with an NGCC unit, and it is not a use of gas that is in any way the efficiency equivalent of a new NGCC unit. (We have similar doubts about co-firing, a measure that may increase ratepayer costs without materially altering the scale of the task confronting the state.) The most recent construction by PacifiCorp of new NGCC capacity has been closer to load (in Utah), a reflection of the fact that existing transmission is not the dominant economic determinant. We think it far wiser to make these decisions in response to the myriad economic and practical considerations that have long been standard in the industry.

In fact, as we explain in further detail later in this comment, there are reasons to believe that the entire Section 111(d) program will cause a contraction of Wyoming's economy, due to its impact on Wyoming's coal industry, *infra*, pp. 21-22; to the premature retirement of a major portion of Wyoming's coal fleet, *infra*, pp. 36-38; and to the resulting increase in electricity rates, which will directly affect the state's economic base of industrial users, who accounted for 58.98% of Wyoming electricity sales in 2012.

If there are practical difficulties with Block 2, rather than spread further misery and practical difficulty by adopting an arbitrary minimum for gas consumption, it makes far more sense to develop a complete understanding of those difficulties and address them. We doubt that EPA will facilitate the success of its entire Section 111(d) proposal by raising more obstacles to successful state compliance.

Block 3 – Expanded Renewable Energy Generating Capacity

EPA explains that Block 3 focuses on renewable energy requirements "established through Renewable Portfolio Standards (RPS), which provide specific quantifiable RE generation requirements over time." TSD, p. 4-2. Generally speaking, an RPS requires a retail seller of electricity to supply its customers with a specified percent of its electricity originating from documented renewable energy sources. Further, states generally have jurisdiction over retail sales within their borders.

However, EPA started its Wyoming calculation with the wrong number, applied an unrealistic growth factor and reached a wrong conclusion. EPA relied on Energy Information Administration (EIA) data for Wyoming wind facilities to quantify Wyoming's 2012 renewable energy generation of 4,369,107 MWh. EPA then applied an annual escalator of 6.095% to this base number beginning in 2017. The escalator is said to reflect past performance in an eleven-state region designated as "the West." The resulting Block 3 portion of Wyoming's overall goal reaches 9,427,996 MWh in 2029.

EPA made no effort to determine what portion of the 4,369,107 MWh was Wyoming consumption subject to Wyoming jurisdiction over retail sales. With or without an RPS, Wyoming RE consumption would be the outer limit of achievable MWh consistent with an RPS theory.

It is not hard to derive a number for renewable energy sold at retail in Wyoming. To do so, Commission staff reviewed the same EIA data used by EPA. For 2012, the format of this data was entries listing Plant ID number, Plant Name, Operator Name, Operator ID number, State, and Net Generation in Megawatts. Commission staff verified the EIA totals for Wyoming wind plants, and readily found internet information to link listed facilities to their ownership and to the location where each facility's generation was consumed.

PacifiCorp facilities accounted for 3,753,653 MWh of the 2012 total (about 86%). The Commission confirmed its understanding that PacifiCorp treats this renewable production as a system asset for the utility's six-state system. As such, retail customers in all six states receive an allocated share of the electricity from the Wyoming wind generators connected to PacifiCorp's system. Commission staff determined the Wyoming share of wind production using a factor which four of the six PacifiCorp states used in 2012 to allocate system costs among themselves. (The 2012 allocation factor for Wyoming was 15.5220%; for Utah, 42.8146%; for Oregon, 25.9294%; for Washington, 7.9620%; for Idaho, 5.7832%; for California, 1.6015%. Less than 0.4% was allocated to another entity.) The factor reflects energy use and system demand, i.e., the system infrastructure required to meet peak demands in each state.

The Commission's result, with percentages showing the portion owned or held by the specified entity, was:

PacifiCorp:

Foote Creek I:	85,758 MWh (79% PacifiCorp)	
Dunlap:	387,973 MWh (100%)	
Glenrock:	427,130 MWh (100%)	
Rolling Hills:	292,022 MWh (100%)	
Seven Mile Hill:	414,750 MWh (100%)	
McFadden Ridge:	94,789 MWh (100%)	
High Plains:	316,599 MWh (100%)	
Campbell Hill:	339,071 MWh (100%)	Contracted
Casper Wind Farm:	45,768 MWh (100%)	Contracted
Rock River:	135,098 MWh (100%)	Contracted
Mountain Wind Power:	171,517 MWh (100%)	Contracted
Mountain Wind Power II;	227,793 MWh (100%)	Contracted
Top of the World Windpower:	660,722 MWh (100%)	Contracted
Foote Creek I:	22,797 MWh (21%)	Exchange
Foote Creek II:	5,498 MWh (100%)	Exchange
Foote Creek IV:	53,878 MWh (100%)	Exchange
Foote Creek III:	72,490 MWh (100%)	Exchange

PacifiCorp Totals: 3,753,653 MWh
3,171,011 MWh (84.4780%) exported
582,642 MWh (15.5220%) to Wyoming (2012 Allocation of 3,753,653 MWh)

Platte River Power Authority:

Silver Sage:	36,856 MWh (28.6%) all exported
Medicine Bow:	17,493 MWh (100%) all exported

Cheyenne Light Fuel & Power:

Happy Jack Wind Farm:	42,514 MWh (50%) all to Wyoming
Silver Sage:	30,670 MWh (23.8%) all to Wyoming

Black Hills Power:

Happy Jack Wind Farm:	42,514 MWh (50%)
Silver Sage:	61,341 MWh (47.6%)

BHP Totals: 103,855 MWh

93,469 MWh (90%) to South Dakota
10,386 MWh (10%) to Wyoming

Iberdrola:
Wyoming Wind Energy Center: 384,066 MWh (100%) all exported

Grand Totals:
Total Exported: 3,702,895 MWh 84.75%
Total Wyoming Consumption: 666,212 MWh 15.25%
Total: 4,369,107 MWh 100.00%

In these calculations, an Exchange refers to an agreement to purchase 100% of the power of a wind facility. However, if PacifiCorp does not need all the power being produced, it may give some power back to its counter-party in a different period. For example, when the facility is not running, the counter-party may give power back to PacifiCorp. The Exchange MWhs are a balance which accounts for these gives and takes. PacifiCorp also receives Network Resource designation for such generation, and as such sinks 100% of the output into Network Load.

We conclude the base for calculated growth of Wyoming renewables should be retail sales of 666,212 MWh, not total renewable generation of 4,369,107 MWh. Using EPA's annual growth factor of 6.095%, the 4,369,107 MWh grows by 5,058,889 MWh to reach the total of 9,427,996 MWh in 2029. As we will show below, this number comprises the single largest component of EPA's goal for Wyoming, and is large enough to frustrate any conceivable state effort to comply with that goal.

The other part of EPA's goal calculation is the regional RPS growth rate. We think it improbable for Wyoming or anyone else to achieve this growth rate. EPA's focus on a cocktail of state RPS goals ignores the forces that have both driven Wyoming wind development and stopped its growth. Consider the EIA data for wind production from 2008 through 2013:

Year	*Megawatt hours produced*
2008	962,542
2009	2,226,205
2010	3,246,793
2011	4,611,868
2012	4,369,107
2013	4,414,734

This is not a pattern of steady growth. Instead, it is a pattern of dramatic growth, followed by ongoing stasis. The reasons are not obscure. The growth was principally the result of resource acquisitions for the PacifiCorp system. The plateau from 2011 on was principally due to reaching the limits of transmission capacity in Wyoming.

Going forward, a reduced rate of PacifiCorp system growth and ratepayer resistance may limit investor interest in new renewables and necessary transmssion. We described this history of rate increases in the letter of December 16, 2013. The increases are not over. Decisions are currently pending in a 2014 general rate case seeking an increase of more than 5% and a 2014 case to pass on increased energy costs.

As of the fall of 2014, PacifiCorp anticipates completion of significant new transmission, known as Gateway West, in 2024. The company has pursued Gateway West through many years of delays, most of which were due to federal constraints on routing and permitting of the transmission line. The Department of Environmental Quality describes these planning concerns and development constraints in separate comments, as well as EPA's flawed assumption of the land available in Wyoming for wind development.

We agree with the DEQ that the correct growth rate for Wyoming is no more than 1%. The Department of Environmental Quality has shown that this is a fair composite of the growth rates embedded in the Renewable Portfolio Standards of the western states. EPA has simply considered state targets without paying attention to the rates at which the RPS states proposed to progress to those targets. The DEQ approach is more consistent with the EPA's stated objective of determining an appropriate rate, and more consistent with the practical impediments to renewables development.

Assuming EPA's construct, EPA could reach the correct goal by substituting 666,212 MWh for 4,369,107 MWh, and 1% for 6.095%, and recalculating Block 3.

Wyoming's power to grow capacity by means other than intrastate sales has been limited by another policy position EPA has taken with respect to Block 3. The following question was posed and answered in the affirmative during a Region 8 conference call with Washington participation: "Does a state (state A) that contracts or has its utilities contract for a renewable project in another second state (state B), get the benefit of the new renewable project outside its border?" Consistent with the RPS construct, EPA has repeatedly assured questioners over the past months that, going forward, credit for new renewables will redound to the benefit of the state of the owner or purchaser of the renewables, rather than to the state in which the renewable facilities are located.

Given the disparity between Wyoming's exports and consumption, the differences between how the goal was derived and credits for future renewable development eviscerate EPA's growth assumptions. For example, production from a 1,000 MW wind farm in Wyoming, which transmits all of its electricity to California, will be used to determine California's compliance with section 111(d), not Wyoming's. We see an analogue in EPA's decision to exclude hydroelectric power from setting goals because "No states are expected to develop any new large facilities." TSD, p. 4-5. In the context of new renewables on a scale that would make it possible to reach Wyoming's Block 3 goal, there is no reason to expect new export facilities to be credited to Wyoming.

One way to address the exported renewables included in the 2012 state total is to simply count them in the calculation of Wyoming's goal compliance going forward, but without applying a growth factor. In other words, the starting point for the calculations leading to the glide path would remain 4,369,107 MWh, but the 3,702,895 MWh would not be escalated. The goal in 2029 would then be 3,702,895 MWh plus 666,212 MWh escalated by 1% annually.

Wyoming would be indifferent to use of the second approach as long as variations in the exported renewables did not add to Wyoming's burden to increase renewables to meet the EPA goal. This could occur through fluctuations in output, through expiration of contracts, and through transfers of interests, among other possibilities. For example, if an existing purchase agreement expired and rights to the production were acquired by a purchaser out of state, the result may be to credit those renewables to a different state. One way to address these possibilities would be by State-proposed adjustments in filings demonstrating compliance. Transfers could simply be retroactively eliminated from the state goal and increases in production could be retroactively added. The common thread in these adjustments would be the state's absence of control over the exported renewables.

Without an adjustment to the compliance goal, Wyoming's original goal would be too high. We also anticipate EPA's ground rule for new renewable projects will eventually apply to existing projects as the reality of Section 111(d) compliance begins to press on utilities and states.

There is a further issue concerning how EPA will measure compliance with Block 3. Since Wyoming has not adopted an RPS, the major premise of EPA's approach is supported only by reaching a number that is equivalent to what an RPS could achieve. A PacifiCorp official has recently testified:

> None of the wind facilities that the Company owns or contracts was acquired due to renewable portfolio standard requirements in any state. Each of the Company's wind resources included in this case is a prudent system resource that contributes to PacifiCorp's diverse and cost-effective portfolio of resources. All of the wind resources are allocated among PacifiCorp state jurisdictions including states such as Wyoming that do not have a renewable portfolio standard. Acquisition of the Company's wind resources has been supported by past integrated resource plans ("IRPs"). For example, the 2008 IRP, as amended by the 2008 IRP Update, indicated a need for additional supply including cost-effective wind resources to serve growing load, replace expiring contracts, and the ongoing obligation to serve customers' energy needs. The Company's most recently acquired owned wind resource, Dunlap, came online in 2010 and was acquired through a fair, transparent and robust competitive bidding process, namely the 2009 Renewable Request for Proposals ("2009R RFP"). The 2009R RFP also resulted in a power purchase agreement for the Top of the World wind project, which also came online in 2010.

Sur-rebuttal Testimony of Gregory N. Duvall, September 19, 2014, pp.1-2, WPSC Docket No. 20000-446-ER-14. Mr. Duvall went on to explain that, aside from the cost-effectiveness of wind resources, PacifiCorp has occasionally purchased wind resources from certain qualifying facilities under the mandates of the Public Utility Regulatory Policies Act of 1978. *Id.*

The absence of a direct link between an RPS and reliable data does not mean there is no reliable data to support a compliance calculation. EIA data demonstrated performance EPA deemed desirable to calculate a Block 3 goal, albeit not for the precise reasons EPA has articulated. If reported EIA data has been good enough to establish performance targets, both EPA and Wyoming should able to rely on this data to measure ongoing performance during the glide path years, whether or not Wyoming adopts an RPS. Given the historic resistance of Wyoming interests to an RPS, the adoption of an RPS would be a significant challenge.

As long as performance can be reliably measured, we see no particular reason why EPA needs to have the state control the underlying motivations and incentives that cause the performance. Direct controls over new renewables credited to the state could raise more questions than it answers. If the State were to adopt an RPS, would that in some way retroactively cause performance previously unrelated to the RPS to be treated as being caused by the RPS? If the state failed to achieve its goal, would EPA really pursue enforcement against a small, recalcitrant rural utility? If the state failed to achieve its goal and EPA wished to pursue Block 3 compliance against PacifiCorp in Wyoming, what compliance could it require when the company asserts that its wind acquisitions were motivated by practical and economic judgments unrelated to an RPS?

We ask that EPA consider it sufficient that EPA has reliable data to determine the required rate of emissions, which includes data concerning renewables, and therefore to determine an overall rate for state compliance. It should be enough that a State plan can offer a compliance path for its overall goal, which may include options related to other blocks or strictly to inside the fence measures, as long as those measures are clearly defined. However, we should again underscore that the MWh associated with the Block 3 component of the state goal are essential for state success.

This leaves the matter of alternative methods of calculation, as previously described in the Alternative RE Approach Technical Support document and more recently described in the NODA of October 27, 2014. The first alternative is based on a calculation of technical and market potential for each state. Potential alone is too slender a foundation for a state goal. At least with the RPS approach, we know what EPA wants the state to do, how the EPA expects the state to do it, and how the measure of compliance relates to the means of complying. We believe the DEQ has persuasively shown how much harder it is to proceed with RE projects in Wyoming than EPA has supposed. Our own discussion of the four Blocks leads us to doubt EPA has a meaningful sense of what Wyoming might do to reach EPA's goals. EPA's boots need to be much closer to the ground.

The regional approach is impractical in the extreme. EPA will recall that Wyoming has three sets of EGUs, operated by entities that reach in different directions, east and west. None of these three operators is affiliated with distribution entities whose territories are coterminous with state boundaries, and two of those operators do business in states that are not part of the West as EPA has defined it. As we will explain in the context of Block 4, *infra*, pp. 26-27, service territories that actually exist do not necessarily share the average characteristics of the states in which they are located. For example, the energy efficiency performance of a rural service territory in California has more in common with Wyoming than with the vast urban areas that dominate any average assessment of that state. EPA's inexplicable affinity for averages has made it blind to the practical definition of common interests that can make a regional entity work.

It should be apparent from our discussion of Block 3 that some criteria about which EPA specifically enquires, i.e., "total electricity sales in each state in 2012" and "total generation in each state in 2012," can only be evaluated if we know how EPA proposes to use the criteria in question. For example, total state RE generation is the wrong standard for an RPS theory if a substantial portion of that generation is exported. Further, the standard should stem from intrastate retail sales of RE, and not from gross intrastate MWh sales, which is a larger and different number. We are concerned that EPA's approach is being driven by the most readily available information, not the most appropriate. As we have demonstrated above, a step beyond the EIA data is necessary to fairly determine Wyoming's RE consumption.

We think it unwise to assume that effective regional cooperation can emerge through a federal mandate, and particularly unwise to assume that regional entities can be established on EPA's ambitious schedule. Normally, the types of questions about regional relationships EPA poses would be answered over time, beginning with state level involvement from interested agencies and, if the occasion warrants, the legislature. The road to multi-state agreement is often a long one, and we predict nothing good will come from presuming that all states will find advantage in a regional approach. Nor do we believe any good will come from EPA circumscribing what the terms of such relationships would be. We believe EPA should be more concerned that it can frustrate regional cooperation by establishing goals that cannot be achieved, by predetermining an unpalatable structure, or by forcing relationships that would not otherwise be of mutual interest.

Block 4 – Demand-Side Energy Efficiency

EPA set goals for the fourth block relying on broad inferences from state successes with energy efficiency (EE) programs. It calculated specific goals by tying these broad inferences to the most recently available Energy Information Administration (EIA) data (calendar year 2012). This overall method has resulted in a goal which is too ambitious for Wyoming.

The cornerstone of the EPA calculation is intrastate sales of electricity, expressed as 16,971,354 MWh spread over 23 entities with retail sales, plus one adjustment not associated with any specific entity. The source of this data was EIA Form 861.

Only two of the listed entities, PacifiCorp and Cheyenne Light Fuel & Power, reported Demand Side Management programs to the EIA in 2012, again on Form 861. EPA rounded reported efficiency savings to 24 Gigawatt hours, then added those hours back to the total reported sales to create a 2012 Business As Usual base case of 16,995 GWh for Wyoming.

EPA next applied an annual growth rate of 0.97% for Business As Usual MWh for years after 2012. This adjusted annual Business As Usual number is one of the drivers of the EPA analysis.

EPA next set goals for annual savings, beginning with the year 2017. It divided the 24 GWh of statewide 2012 savings by the escalated 2017 Business As Usual sales, which yielded 0.13% first year energy efficiency (EE) savings. For the next year (2018) and years thereafter, EPA increased the base percentage by 0.2% (0.33% in 2018, 0.53% in 2019, and so on) to calculate a number for annual incremental savings expressed in GWh, i.e., 59 GWh in 2018, 96 GWh in 2019, and so on. EPA continued to escalate the first year savings by 0.2% each year until 2024, when the percentage of first year savings topped out at 1.5%.

The final step was to calculate annual state goals from 2017 through 2029 to reflect net cumulative savings, expressed both as GWh and a percentage of sales before EE measures. Net cumulative savings are the difference between annual incremental savings and expiring savings. EPA determined expiring savings by assuming that all EE measures will have a useful life of 19 years. By 2029, EPA's calculation of Wyoming's net cumulative savings reaches 1,950 GWh and 9.73%.

We believe EPA's method overstates the practically possible net cumulative savings. First, the 2012 gross intrastate sales figure includes sales that should not be counted. The EIA entries that made up gross intrastate sales were:

Utility	*Total MWh Sales*
Basin Electric Power Coop	4,435
Beartooth Electric Coop, Inc	7,604
Big Horn Rural Electric Co	115,953
Big Horn County Elec Coop, Inc	4,249
Bridger Valley Elec Assn, Inc	137,157
Carbon Power & Light, Inc	166,944
Cheyenne Light Fuel & Power Co	1,076,746
City of Cody	111,437
Fall River Rural Elec Coop Inc	7,724
Garland Light & Power Company	26,456
City of Gillette - (WY)	311,356
High Plains Power Inc	999,637
Lower Valley Energy Inc	630,113
Montana-Dakota Utilities Co	283,221
NorthWestern Energy LLC - (MT)	25,709
PacifiCorp	9,498,107
City of Torrington - (WY)	107,565
Powder River Energy Corp	2,711,137
Black Hills Power Inc	171,046
Wyrulec Company	100,151
Yampa Valley Electric Assn Inc	10,520
WAPA-- Western Area Power Administration	33,968
High West Energy, Inc	120,784
Adjustment 2012	309,335

The sales for **Lower Valley Energy Inc** should be excluded because the energy efficiency achieved by LVE was reported by the Bonneville Power Authority, following instructions for EIA Form 861: "…. Federal Power Marketing Administrations should coordinate with the reporting of DSM information with their power purchasing utilities to avoid double counting the effects and costs of DSM programs." BPA confirmed to LVE that "BPA Energy Efficiency already reports all reportable savings (both utility and BPA implemented) to the Power Business Line which in turn is reported to EIA." This is not an instance of "disaggregation of reported data by state for administrators with programs in multiple states," as referenced on p. 5-16 of the GHG Abatement Measures TSD. Where efficiency effects have been reported by an entity other than a utility listed for Wyoming, the goal calculation should not include related Wyoming sales.

The sales for **Powder River Energy Corp** (PRECorp) should be excluded because EPA policy is intended to induce a decline in the economic base of the company's Campbell County service territory, which will in turn make customary energy efficiency programs infeasible. The company's service territory includes eight of the ten largest coal mines in the United States, collectively responsible for over 336 million short tons of coal in 2012. EIA Today in Energy, March 29, 2013; Wyoming Mining Association, 2012 Coal Production by County. EIA's most recent profile of Wyoming adds, "In recent years, Wyoming coal has been used at power plants in more than 30 states, and has supplied 9 states with more than nine-tenths of the domestic coal they consumed."

Although EIA predicts long term growth for Wyoming's low sulfur coal, a recent study specifically considers the impact of section 111(d) regulations and predicts the opposite. The study was described in a New York Times article of July 24, 2014, under the headline, "States Against E.P.A. Rule on Carbon Pollution Would Gain, Study Finds." While demand for natural gas would drive growth in states like Oklahoma and Texas, "The report concluded that the rule would hurt states where coal production is a central part of the economy – chiefly Wyoming, the nation's largest coal producer. . . . While Texas currently buys coal from Wyoming and burns it for electricity, it would be able to comply with the new rule by ceasing to buy that coal and instead producing and burning more low-carbon natural gas within the state."

The Rhodium Group prepared the study in question, and one of its representatives made a more detailed presentation of the study findings to the Wyoming Infrastructure Authority on October 7, 2014. http://wyia.org/wp-content/uploads/2014/10/trevor-houser-1.pdf. Under four scenarios, the Rhodium Group forecasts a decline in Wyoming coal production of 31% to 49%, comparing 2020-2030 to 2014. Slide 15. It forecasts similarly dramatic declines in coal prices. Slide 16.

Energy efficiency programs are commonly structured through a surcharge on utility rates, creating a pool of funding that can be used to generate offerings to utility customers. This arrangement can work well in periods of growth. As the TSD puts it, "The opportunity for investment in EE is dynamic, growing over time as technologies and practices advance, as populations grow, and as investment occurs in the construction of new homes, buildings, and industrial facilities." (p. 5-4).

But this does not apply during a period of economic contraction. Many of a utility's costs are fixed, and still must be recovered from declining numbers of customers. Usage also tends to decline, which reduces recovery available through energy charges. The result is that rates tend to rise, since they are being recovered from a smaller base. Under a growth scenario, energy efficiency can relieve the expense of growth for all ratepayers, but energy efficiency cannot similarly relieve the expense of decline. The market failures which are the nominal reason for the program cease to provide a compelling explanation for efficiency surcharges; ratepayers must instead contend with the consequences of depopulation and maintenance of existing services for a smaller customer base.

While the timing of the effects of the regulations on coal production may be uncertain, PRECorp is already feeling the effects of economic contraction, from another source. Coal bed methane has moved from rapid growth to rapid decline in a short period of time. Minimum contract billing requirements have cushioned the fall in demand, but these contracts will expire over the coming years. From 2006 through 2013, the KWh sold to coal bed methane subclasses of the industrial class dropped by 37 percent, and metered KWh for the same subclasses dropped 65 percent (reflecting the difference between minimum billing and actual usage). Overall, in 2010, PRECorp reported 2,927,689 MWh sold to EIA; in 2011, 2,875,595 MWh; in 2012, 2,711,137 MWh. These circumstances prompted the utility to file a rate case in 2013, and a rate increase of 3% was approved several months ago.

If the EPA's section 111(d) program is successful, the consequences will be drastic and lasting in PRECorp's five county service territory. It is unreasonable to treat that PRECorp's future under section 111(d) as a growth situation to be included in Wyoming's energy efficiency target.

The **Western Area Power Administration** (WAPA) is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. It sells power to preference customers such as Federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts and Native American tribes. They, in turn, provide retail electric service to consumers in the West. As a federal agency over which the state exercises no control, it should be excluded from setting the state's goal for energy efficiency.

Basin Electric Power Cooperative (Basin Electric) is one of the largest electric generation and transmission (G&T) cooperatives in the United States. It is not a local distribution company, and Commission staff confirmed that the only transactions with its two customers in 2012 were wholesale. Willwood Light & Power is a local distribution company which reported sales of its own on Form 861S (see below), so it would be double counting to include the sales to Willwood under Basin's auspices. F.E. Warren Air Force Base is a federal military installation over which the state exercises no economic regulatory control. Basin's sales to F. E. Warren Air Force Base ended in 2013.

The entry labeled **Adjustment** is actually an assortment of fourteen entities (nine municipal, four cooperative, and one political subdivision) small enough to file an EIA Form 861S, which is a short version of the Form 861. Form 861S does not require quantities for energy efficiency. All of these entities were individually listed by EIA in 2011. As an example of scale, in 2011 Midvale Irrigation District had total revenues of $3700 and six customers. Southeast Electric Coop is actually a Montana coop with 10 Wyoming customers. Willwood Light & Power Company had 49 customers, all residential. The largest of the other entities is the Wheatland Rural Electric Association, with 3,717 customers. Only four other entities had more than a thousand customers.

If these entities are too small to have to quantify energy efficiency, they should be too small to be included in the basis for the state target. Doing so would take the EPA too far into the depths of rural America, and subject the entities to administrative and regulatory demands which are unreasonable in light of the benefits to the nation, and which are unreasonable in light of the compliance expectations which EPA has articulated in its TSD on State Plan Considerations.

If these exclusions are made, the cornerstone for intrastate sales is 13,282,366 MWh. Adding back 24 gigawatts, the Business As Usual case for Wyoming would be 13,306,366 MWh. The calculated cumulative savings should be counted against this reduced base.

With the exclusions, the Commission would accept EPA's .97% growth rate as being within a reasonable range. It is important to note that, as shown on Wyoming's album on EIA's Flickr page, in 2013 Mining had nearly a 35% share of the Wyoming economy, nearly fourteen times higher than the nation as a whole, and higher than any other state. Given this sector leverage, the actions that EPA intends to affect the coal and power sectors of Wyoming's economy will affect the state as a whole. Without the exclusions, the .97% is excessive.

The second reason EPA's goal is overstated is that EPA's .2% escalator for first year incremental savings is unreasonable, as is the ultimate annual target of 1.5%. EPA should consider the experience of Wyoming's largest utility, PacifiCorp, which has had an energy efficiency program in Wyoming for four full years. PacifiCorp's EE program offerings are virtually identical to those in five other PacifiCorp states. Expressing the growth of the Wyoming energy efficiency program (final numbers for efficiency were taken from annual reports to Wyoming Public Service Commission and vary slightly from Form 861) as a function of total PacifiCorp intrastate sales, we see:

Year	Efficiency effects MWh	Company's gross intrastate sales MWh	Efficiency as % of total sales
2010	21,879	9,680,088	.23%
2011	13,915	9,792,811	.14%
2012	23,254	9,498,107	.24%
2013	27,857	9,541,957	.29%

After a successful program inception, PacifiCorp has been unable to manage anything approaching incremental growth of .2%. Its best year for growth was .1%, but only after declining .09% from the previous year. Its next best increase was .05%. In each of these years, the Wyoming Public Service Commission approved all of the proposed program expenditures PacifiCorp sought.

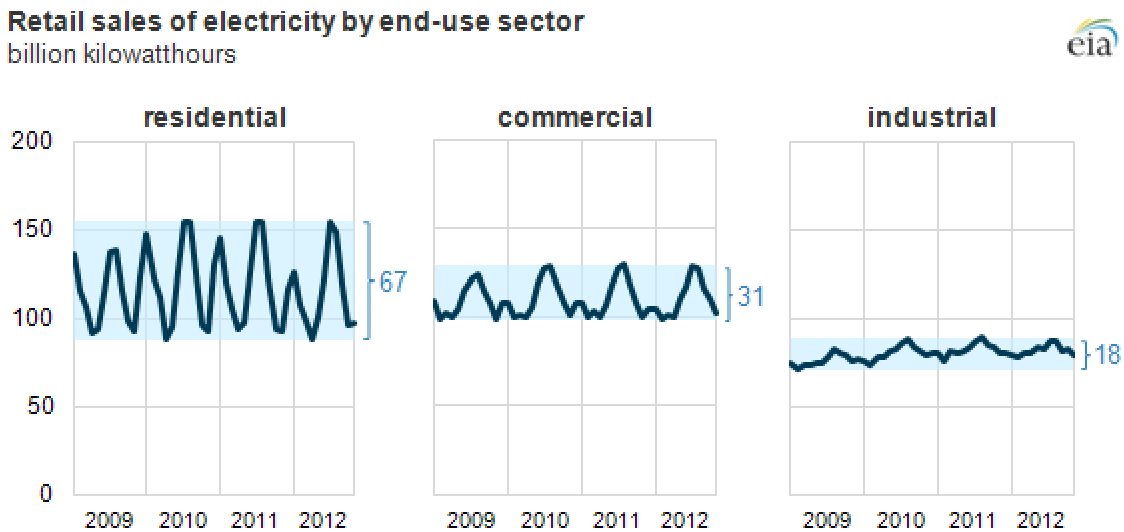
Cheyenne Light Fuel & Power conducts the only other Commission-regulated energy efficiency program in Wyoming. We are approaching the conclusion of its three year pilot program. Its effort to apply a template of program offerings from other jurisdictions has been disappointing. In its first year, it planned 6,124 MWh of effects for its residential and commercial/industrial programs, and achieved only 2,030 MWh. (2012-2013 Annual Report). Compared to 2012 total sales of 1,076,746 MWh, this represented annual incremental savings of .19%, somewhat less than PacifiCorp's first year, but more than PacifiCorp's second. There is no reason to believe its program growth rate will match or exceed PacifiCorp, although like PacifiCorp, the Commission has approved all requested expenditures, with one minor exception described below.

Wyoming's ability to achieve energy efficiency goals is affected by the heavy weighting of industrial use in its electricity consumption. 2012 industrial sales in Wyoming were 58.98% of statewide total sales, a substantially heavier proportion than the next closest western states, Idaho (40.38%) and Nevada (39.04%). The general rule in the west, readily apparent from the EIA data for 2012, is that energy savings do not keep pace with industrial sales (we duly note 2012 exceptions in Idaho and Oregon). The PacifiCorp data for Wyoming follows the general rule, with industrial efficiency effects being about .1% of sales, while residential efficiency is about .7% and commercial efficiency is about .5%:

PacifiCorp	2012 Sales MWh	2012 EE Savings MWh
Residential	1,052,691	7,329
Commercial	1,596,291	7,223
Industrial	6,849,125	6,970
Total	9,498,107	21,522

Cheyenne Light Fuel & Power did not report any 2012 efficiency savings associated with its industrial class to EIA, although its commercial program was available to industrial customers.

Predominance of the industrial sector makes a difference. As the EIA observed in its March 4, 2013 issue of Today in Energy, the national industrial sector's demand for electricity is relatively flat compared to the other two sectors (see diagram below). Rate cases have shown that the same is essentially true in Wyoming on a daily and weekly basis. The EIA sketched the practical context: "Serving an industrial customer tends to cost less on a dollars-per-megawatt hour because there is less hourly and seasonal variation in demand. Industrial facilities often run 24 hours a day to avoid ramp-up times or to meet manufacturing requirements. Also, industrial customer can take advantage of interruptible service contracts, in which the customer agrees to reduce its electricity use when the utility asks, in exchange for a lower rate. At such time, the industrial facility can switch to onsite backup generation or shut down temporarily."



Stated another way, the industrial sector makes more efficient use of the electrical system from the outset. The potential for efficiency gains is greatest for the residential class, and least for the industrial class. The rough orders of the differences of potential are shown in the diagram above.

Industrial sales affect energy efficiency programs in several ways. First, the nationally familiar programs for residential and commercial sectors have much less overall impact in Wyoming. If Arizona's outstanding program rates of success were achieved, but with the weight of Wyoming's sectors, Arizona's high overall first year savings performance would drop from 1.61% of sales to 0.76% of sales:

	Arizona Energy Efficiency Rate	Arizona Customer Class Percentage	Arizona Class Adjusted Energy Efficiency Rate	Wyoming Customer Class Percentage	AZ EE Rate Redistributed using Wyoming Customer Class Percentage
Residential	2.22%	43.86%	0.97%	16.01%	0.36%
Commercial	1.62%	39.56%	0.64%	25.02%	0.41%
Industrial	0.00%	16.58%	0.00%	58.98%	0.00%
Total		100.00%	1.61%	100.00%	0.76%

Second, the relatively constant demands on the system reduce the economic consequences of daily fluctuations in electricity demand, and in doing so, reduce the attraction of many common demand side management measures. Time of use pricing, for example, has never found favor in Wyoming, because peak demands are already modulated into insignificance by industrial loads. The system efficiencies also keep prices to all consumers somewhat lower, dampening the economic appeal of energy efficiency programs.

Third, industrial energy efficiency opportunities tend to be dominated by the character of the industry, and its capital cycles. A significant percent of PacifiCorp's overall Wyoming load is fewer than three dozen large industrial customers. About 85% of PacifiCorp's industrial usage is related to mining and mineral extraction. When commodity prices are up, these customers are normally preoccupied with producing as much as possible; when prices are down, the same customers are focused on cost cutting, and capital budgets are constrained. Opportunities to influence decision makers may take years to develop.

Further, PacifiCorp has concluded, based on a study prepared to support its upcoming Integrated Resource Plan revision, that 75% of the Wyoming industrial energy efficiency opportunity through 2034 is tied to process loads, and hence to motors, compressors, pumping, and the like. This type of equipment often has a long life and represents expensive investment with little analogue to a residential context. Industrial customers tend to be receptive to addressing energy efficiency possibilities when the motor fails, but otherwise tend to avoid disturbing ongoing operations to install new capital equipment.

As a corollary to the capital cycle and efficiency opportunities, first year industrial energy efficiency savings tend to be lumpy – up one year and down the next. This is true of industrial opportunities in other states as well (a California example appears below). EPA's decision to rely on one base year, supplemented mainly by assumptions, masks significant year-on-year variations in data, and particularly industrial data. It is not clear that this lumpiness can be smoothed out by something as simple as a three year average, given the lengthy lives of heavy capital equipment.

Fourth, industrial customers present a service risk. If electricity prices are driven too far, too fast, industrial customers are capable of self-generation, and leaving the company's customer base. This gives added poignance to the PRECorp problem described above. Efficiency programs that do not demonstrably add value may drive industrial customers off the grid.

Aside from its industrial base, Wyoming is also affected by an urban/rural divide. This is illustrated by PacifiCorp's experience and reflected in EIA data. PacifiCorp prepares and files Form 861 data for its service territories in six states: Wyoming, Idaho, Utah, Oregon, Washington, and California (in Oregon, PacifiCorp data is consolidated with the filing of the Oregon Energy Trust and hence not shown). It offers essentially the same energy efficiency programs in all six states, but its service territories in every state but Utah tend to be rural with dispersed populations. The data readily available from EIA includes:

	Wyoming	Idaho	California	Washington	Utah
Totals					
EE effects	21,522	11,420	5,770	45,598	217,608
MWh sales	9,498,107	3,517,627	782,661	4,041,898	23,930,266
% of sales	0.23%	0.32%	0.74%	1.13%	0.91%
Residential					
EE effects	7,329	3,674	2,325	21,550	94,690
MWh sales	1,052,691	675,655	386,321	1,596,276	6,851,903
(Revised EE)				7,940	
% of sales	0.70%	0.54%	0.60%	1.35%	1.38%
(Revised EE)				0.50%	
Commercial					
EE effects	7,223	2,205	1,131	12,173	93,878
MWh sales	1,596,291	439,776	276,024	1,457,584	8,441,235
% of sales	0.45%	0.50%	0.41%	0.84%	1.11%
Industrial					
EE effects	6,970	5,541	2,314	11,875	29,040
MWh sales	6,849,125	2,402,196	120,316	988,038	8,598,954
% of sales	0.10%	0.23%	1.92%	1.20%	0.34%

Looking at the residential performance in the five service territories, the best performance is in Utah, the most densely populated service territory. Performance in the sparsely populated service territories in Wyoming, Idaho, and California is less than half of Utah. Wyoming outperforms California in the residential context. It is important to remember that overall state performance is not necessarily indicative for a rural territory. Further, rural territories may have more in common with one another than with their respective states.

PacifiCorp views Washington as being similar to its other rural territories. In 2012, 13,610 MWh of the company's reported residential efficiency was related to market transformation savings reported by a regional non-profit organization in which PacifiCorp participated. Market transformation typically involves market intervention, typically upstream and ahead of utility programs, working with product manufacturers and retailers to build and stock higher efficiency products than would otherwise be available over a similar timeline. This includes intervention in the supply chain of big box stores like Costco, as distinct from programs which typically involve offerings directly to ratepayers. PacifiCorp only applies for ratepayer support when there is a reasonable relationship between the supply chain intervention and its service territory. This does not include Wyoming. In PacifiCorp's Wyoming territory, there is neither a Costco nor a Lowe's. PacifiCorp's trade allies for its appliance program include only two Home Depots, five K-marts, two electric supply stores, five Sears stores, a Sutherlands, seven Walmarts, and a Sam's Club, for a service territory occupying more than a third of the state. If one eliminates the market transformation activity, Washington's program performance falls to the low end of residential performance in the five service territories.

Much the same pattern applies to commercial performance, with Utah again being well in the lead with 1.11%, and this time, California the laggard with .41%.

In the industrial class, California is the 2012 leader with a 1.92% performance, although with sales that are a small fraction of either Wyoming or Utah. In the Form 861 filed by PacifiCorp for 2013, California's savings drop to 786 MWh from 2314 MWh the preceding year, and its overall performance percentage dropped to .56% from .74%.

There is not time during the comment period to prepare a formal study of why rural service territories underperform, but part of the answer is density. Wyoming has only six people per square mile, fewer than any state but Alaska. As noted above, this affects markets and opportunities available to the consumer. It also affects all aspects of program design, administrative expense, and customer service. For example, the refrigerator retirement programs of PacifiCorp and Cheyenne Light Fuel & Power relied on the same out of state contractor with out of state personnel, and often required wait times of several weeks before an appliance was removed – a deferral not popular with customers. The contractor now has one location in the state.

Further, programs have been imported into Wyoming without sufficient thought about how likely they are to succeed. When Cheyenne Light Fuel & Power first proposed an efficiency program, its consultant relied on a portfolio of measures that had been successful with sister companies in other states. The consultant's budget included 100 high efficiency electric water heaters. Skeptical because hot water was commonly heated with natural gas supplied by the same utility, the Commission authorized a budget that included 50 units. After a year, only one customer had taken advantage of the offering, which was then eliminated because the volume was too low to support administrative expense.

The reason for failure may be obscure. In February 2013, PacifiCorp attempted to augment distribution of CFLs by mailing 28,000 coupons to customers in ten cities in Wyoming, redeemable at Walmarts in three cities. Only 193 coupons were redeemed – a response rate of .69%. The program was cancelled.

Air conditioning is another source of insight for residential consumption. While there is not granular federal data on the penetration of central air conditioning in Wyoming, periodic PacifiCorp surveys of appliance saturation provide suggestive data that reflects on residential consumption in PacifiCorp's service territories:

State	Survey year	CAC Saturation
California	2006	10.0%
Idaho	2006	15.0%
Oregon	2013	19.4%
Utah	2013	66.0%
Washington	2006	46.0%
Wyoming	2012	23.2%

Confidential survey information used by permission. PacifiCorp generally observes that the addition of air conditioning increases residential consumption by forty percent. 2014 Rocky Mountain Power General Rate Case, Volume 3, p. 642, lines 6-13.

With EIA data available for 2010 to 2013, we can summarize the performance in PacifiCorp's five service territories with percentages of annual incremental savings, broken out by class:

	2013	2012	2011	2010
Wyoming	**0.27%**	**0.23%**	**0.14%**	**0.23%**
Res	0.79%	0.70%	0.65%	0.68%
Com	0.47%	0.45%	0.28%	0.26%
Ind	0.15%	0.10%	0.03%	0.15%
Idaho	**0.51%**	**0.32%**	**0.26%**	**0.36%**
Res	0.46%	0.54%	0.52%	0.63%
Com	0.60%	0.50%	0.50%	0.87%
Ind	0.50%	0.23%	0.13%	0.18%
California	**0.56%**	**0.74%**	**0.79%**	**0.36%**
Res	0.62%	0.60%	0.66%	0.50%
Com	0.47%	0.41%	0.32%	0.17%
Ind	0.54%	1.92%	2.30%	0.35%
Washington	**1.03%**	**1.13%**	**1.15%**	**0.97%**
Res	0.93%	1.35%	1.63%	1.14%
Com	0.49%	0.84%	0.47%	0.67%
Ind	2.06%	1.20%	1.37%	1.09%
Utah	**1.01%**	**0.91%**	**1.05%**	**0.90%**
Res	1.97%	1.38%	1.85%	1.38%
Com	0.81%	1.11%	0.71%	0.66%
Ind	0.44%	0.34%	0.76%	0.74%

Based on Wyoming's experience, we assume that all of these jurisdictions have provided PacifiCorp with all the resources the company requested to conduct its programs. There is nothing in the documented experience of the rural service territories to suggest that EPA's steady annual increase of .2% a year is feasible or reasonable. To the contrary, actual experience suggests that increases will be much less dramatic, and difficult to sustain.

There is also nothing in this data to support a final rate of 1.5%, or to support EPA's view that a rate of 1.5% first year savings can be sustained. The 1.5% becomes even more problematic when considered in light of EPA's intended results for Wyoming's economic base. It is also speculative in view of the fact that the majority of expected savings will be in lighting (see discussion below), and the rate lighting savings will be declining. The change from historical incandescent lighting technology to more efficient incandescent lights and to CFL has already been largely accomplished now that federal standards have been implemented. The savings resulting from a transition to LED bulbs from CFL bulbs are far less dramatic.

We understand that part of EPA's intention is to challenge states to higher levels of performance, but it is one thing to present a challenge, and another thing entirely to set a standard which no one can reasonably expect to be accomplished. An annual increment of .1% and a final rate of .75% would be a challenge. An annual increment of .2% with a final rate of 1.5% is a non-starter.

The second reason EPA's goal is overstated is that EPA's assumption of the life of a portfolio measure at 19 years is too high. 19 years over-inflates the cumulative results. EPA's calculations for Block 4 use nineteen years as the portfolio measure life. E.g., Data File: GHG Abatement – Scenario 1 (XLS), Reference Table, Measure Decay Schedule. The rationale for this number is to assume that a portfolio of measures with an average life of ten years will be evenly distributed with measures ranging from one year to twice the average life, or twenty years. TSD, p. 5-36. Residential and commercial measures with greatest longevity are associated with structural elements of buildings, but the opportunities for energy efficiency improvements to structural elements are much reduced where electricity is not the dominant source of energy for space heating and cooling, and water heating.

As reported to and by the EIA, in 2009, 41.5% of national residential energy consumption was for space heating; 6.2% was for air conditioning; 17.7% was for water heating; and 34.6% was for appliances, electronics, and lighting. In other words, about two thirds of United States energy usage goes to heating and cooling of air or water.

Census data shows that state patterns of heating and cooling differ dramatically. The Selected Housing Characteristics, 2008-2012 American Community Survey 5-Year Estimates provide state by state data on the heating of houses. The following list shows electricity and its principal heating alternatives, for the states EPA has identified as achieving levels of incremental annual savings of 1% or more. (GHG Abatement Measures TSD, p. 5-33). We have added Wyoming to the list for comparison:

	House Heating Fuel	
State	*% Utility gas, propane, fuel oil, wood*	*% Electricity*
Arizona	40.5	58.2
Maine	93.8	4.6
Vermont	93.6	4.5
California	71.9	24.9
Connecticut	84.1	15.1
Iowa	80.9	17.7
Michigan	91.3	7.6
Minnesota	83.1	15.1
Oregon	50.4	48.5
Pennsylvania	77.7	20.1
Wisconsin	84.8	13.9
Wyoming	77.4	20.9

Obviously, if a house is heated by something other than electricity, there are fewer opportunities to implement efficiency programs with long-lived structural elements. In Wyoming, where 71.5% of homes are heated with utility gas or propane, programs addressed to structural elements are mainly the bailiwick of local gas distribution companies, including the gas distribution side of companies providing both electric and gas service. The use of gas and propane for space heating tends to carry over to water heating as well. While the energy for water heating may be different in the New England states which rely heavily on fuel oil for space heating, the list shows that a clear majority of states predominantly heat with something other than electricity.

Since so much Wyoming heating is done with gas and cooling is often not done at all, one would expect that appliances, electronics, and lighting would dominate residential portfolios of efficiency measures. PacifiCorp's 2013 annual report to this Commission confirms the expectation with respect to the Home Energy Savings Program:

Specific Measures (in KWh)	*Space heating*	*Air conditioning*	*Water heating*	***Lighting, etc.***
Attic insulation	883,499			
Ceiling Fan		636		
Central A/C Equipment		1,240		
Clothes washer				88,070
Desktop computer				154
Dishwasher				15,945
Duct sealing and insulation	587,571			
Electric water heater			5,100	
Evaporative cooler		9,864		
Fixture				137,826
Flat Panel TV				226,256
Floor insulation	16,297			
Freezer				2,360
Heat Pump Water Heater			2,120	
Monitor				14
Portable Evaporative Cooler		2,530		
Proper CAC sizing		1,260		
Refrigerator				22,396
Room air conditioner		3,772		
Ductless heat pump	25,110			
Wall insulation	4,937			
Windows	1,001			
Lighting - CFL general				4,172,581
Lighting - CFL specialty				1,407,027
Total	1,518,415	19,302	7,220	6,072,629
% of total	19.93%	0.25%	0.09%	**79.72%**

The Home Energy Savings program contributed 7,617 MWh to PacifiCorp's residential programs in 2013. A refrigerator and freezer recycling program contributed another 913 MWh of savings, again related to the lighting and appliances category. A supplemental Low Income Weatherization program did not report on KWh saved with respect to specific measures. In short, the data confirms the program was heavily oriented to lighting.

PacifiCorp's commercial programs had a similarly heavy reliance on lighting. In 2013, for its small and large commercial programs grouped as FinAnswer Express, 77% of the 7,551 MWh of energy efficiency savings were in lighting programs. Based on a study prepared to support its upcoming Integrated Resource Plan revision, PacifiCorp anticipates that 58% of the Wyoming commercial energy efficiency opportunity through 2034 will be in interior and exterior lighting.

PacifiCorp uses a portfolio life of 10 years for its lighting projects. By using 19 years, EPA has assumed a value that cannot be proven, and calculated a target that cannot be met. If EPA is going to assume a value, 10 years for all measures would be more appropriate.

Aside from EPA's overstatement of the goal, there are also reporting and compliance issues with Block 4. First, a requirement for EM&V is fair for companies that already do EM&V as an integral element of a comprehensive program. EPA's compliance measurement will presumably abide by state-approved schedules for program evaluation. EM&V is not necessary for every program and every year, largely because it drives up costs.

Second, EPA should allow simplified reporting for entities that do not have formal programs with formal EM&V functions. Form 861 is filed under penalty of perjury, which should be enough prima facie assurance for companies with sales below 1,000,000 MWh. If/as formal programs with EM&V functions evolve, the reporting function can evolve in parallel. However, for companies that have little or no experience with energy efficiency programs, the administrative requirements for a formalized program will deter participation.

Third, EPA should accept any state plan which limits Block 4 enforcement to disallowing efficiency savings that EPA fairly determines have been inadequately demonstrated. Efficiency savings would affect the calculation of a state's compliance with a target rate, but not necessarily anything more. In the efficiency context, EPA is not in a position to step in to the shoes of a public service commission. It has no experience or expertise with the design and implementation of programs that rely heavily on establishing surcharges for ratepayers, and attracting the voluntary participation of utility customers. As important, the state's own compliance measures are largely limited to disallowing recovery of costs that are unwisely incurred, not stepping into the shoes of program operators or dictating alternative program choices.

The NODA: Implementation of the Goal-Setting Equation

We are confused by the proposal to explicitly replace fossil generation by anticipated RE and EE. Reducing Block 1 generation by Block 2 re-dispatch made sense to us because the displacement was essentially of a like kind, and gave every appearance of taking place before 2020. Such an explicit displacement was necessary in order for EPA's proposal to be something other than an irrational command to flood existing markets with new, more expensive generation. The majority of RE and EE effects take place during the ten year glide path, and the majority of EE savings may well be deemed savings. (EE programs in which a utility exercises direct control, such as cycling of air conditioning when needed, do not exist in Wyoming.) We believe RE and EE effects to be more speculative in their implementation.

For us there is also an ambiguity in whether EPA would eventually intend independently measurable reductions in coal fired EGU dispatch based on reductions to Block 1 generation. We do not believe this would be desirable, or consistent with the proposed rule as it has been articulated to date.

Most of all, we are at a loss to understand the practical implementation EPA anticipates. Wyoming exports about 60% of its Block 1 generation. Would Block 3 and 4 savings apply to all of that production? Would Block 3 and 4 savings from other states apply to Wyoming's Block 1 exported production? If Block 3 and 4 savings only apply to Wyoming generation related to intrastate retail sales, is there some expectation about how the savings would be allocated among Block 1 generators?

If, by 2020, Wyoming has been obliged to prematurely retire a large portion of its coal fired EGUs, *infra*, pp. 34-37, how would the Block 3 and 4 savings anticipated between 2020 and 2029 either apply to the retired generation, or apply to the remaining generation?

Some Wyoming wind generation is not associated with either Wyoming EGU operators or local distribution in Wyoming. Should those Block 3 hours apply to Wyoming Block 1 generation, and if so, on a proportionate basis? Should those Block 3 hours apply to Block 1 generation in another state? Should they simply be ignored?

Wyoming has three EGU operators only two of which are related to formal EE programs. Would those savings apply only to Block 1 generation directly affiliated with those programs?
Here, the issue of whether there are positive or negative consequences associated with a reduced Block 1 goal may directly affect the incentives of the EGU operators.

These questions are symptomatic of issues we have raised in our comments concerning the shortcomings of EPA's practical understanding of the utility operating environment. Rather than add another layer of complications, EPA would be better advised to step back and ask whether its proposed goals are reasonable, and whether the states have a fair opportunity to succeed in implementing the Section 111(d) program.

Conclusion – the Effect of the EPA Goal

We commend EPA for the transparency of its spreadsheet calculations. We have been able to compute a comparison between EPA's proposed goal and what we believe would be the outer limit of the practical for Wyoming. To do so, we begin with the same ten power plants referenced in Block 1 and subject to Section 111(d), this time with the emissions and MWh production which give rise to EPA's goal:

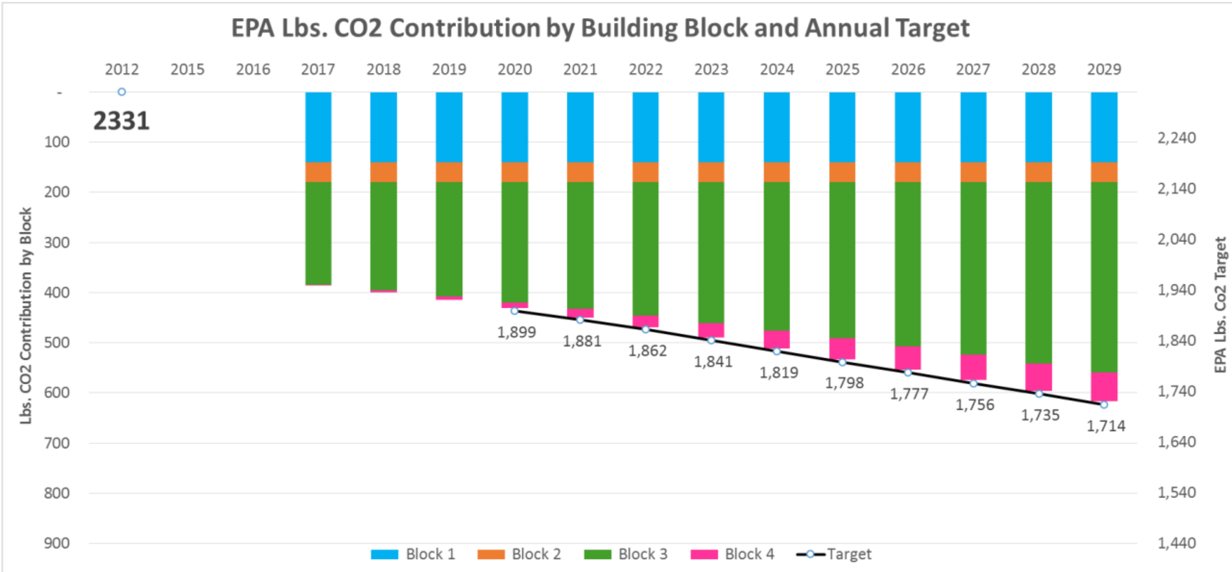
Current Coal Plants	Sum of Carbon Dioxide (tons)	Sum of Net Energy Output (MWh)	Emission Rate (lb/MWh) - net energy output	Emission Rate (lb/MWh) - after 6% Heat Rate Reduction
WY TOTAL	**49,998,736**	**42,907,427**	**2,331**	**2,191**
Dave Johnston	5,720,671	4,906,510	2,332	**2,192**
Dry Fork Station	3,555,713	3,093,371	2,299	**2,161**
Jim Bridger	14,994,886	13,625,135	2,201	**2,069**
Laramie River Station	13,324,303	10,997,853	2,423	**2,278**
Naughton	5,661,930	5,064,299	2,236	**2,102**
Neil Simpson II	780,568	568,601	2,746	**2,581**
Wygen 1	895,126	684,671	2,615	**2,458**
Wygen 2	745,459	587,832	2,536	**2,384**
Wygen III	1,004,748	855,131	2,350	**2,209**
Wyodak	3,315,332	2,524,024	2,627	**2,469**

Since Wyoming had no NGCC plants in operation in 2012, the combined emission rate of 2331 lbs/MWh is the starting point for EPA's goal calculation. That calculation, with certain inputs highlighted to show what we will be modifying for the sake of comparison, is:

	WY Simulation (lbs/MWh)	EPA Calcs (lbs/MWh)	
Step 1	2,331	2,331	2012 Fossil Fuel Emission Rate
Step 2	2,191	2,191	6% Heat Rate Improvement
Step 3a	2,191	2,191	Re-Dispatch Existing NGCC Capacity
Step 3b	**2,151**	2,151	Re-Dispatch Existing and Under Construction NGCC
Step 4a	2,151	2,151	Re-Dispatch Existing and Under Construction NGCC and Nucle
Step 4b	1,771	1,771	Renewable Energy
Step 5	**1,714**	**1,714**	DSM/EE

Change	**6%**	Plant Heat Rate Improvement (%)
These	**907.0**	CPGS lbs/MWh
Inputs	**220**	Capacity Under Construction
	9,427,996	Renewable Energy by 2030 (MWh)
	9.73%	DSM/EE (MWh)
	6.095%	Renewable Energy Growth Rate

The result for Wyoming can be depicted as a bar graph showing Wyoming's glide path as proposed by EPA:



At this juncture, we observe the dominant influence of the renewables component. The misuse of gross renewables generation is a central problem in EPA's proposed goal, one which renders meaningless any general appeal to flexibility.

We will now make changes to the calculation consistent with our comments. It is important to note that we are not proposing a goal, because some of these modifications come with caveats attached, such as our concern that the Block 1 goal cannot be sustained because the other Blocks work against heat rate by reducing plant capacity. Nor is the Public Service Commission the agency that will be charged with preparing the State's plan. Nonetheless, caution can too easily stand in the way of insight.

So, we will adjust Block 1 to 2%.

We will correct Block 2 to 95 MW.

We will adjust Block 3 by escalating the portion of state-generated renewables subject to retail sale in the state, 666,212 MWh, using the 1% annual escalation rate supported by the Department of Environmental Quality. We do so knowing that any proposal for a renewable portfolio standard is likely to be met with hostility, and will pose difficult practical challenges.

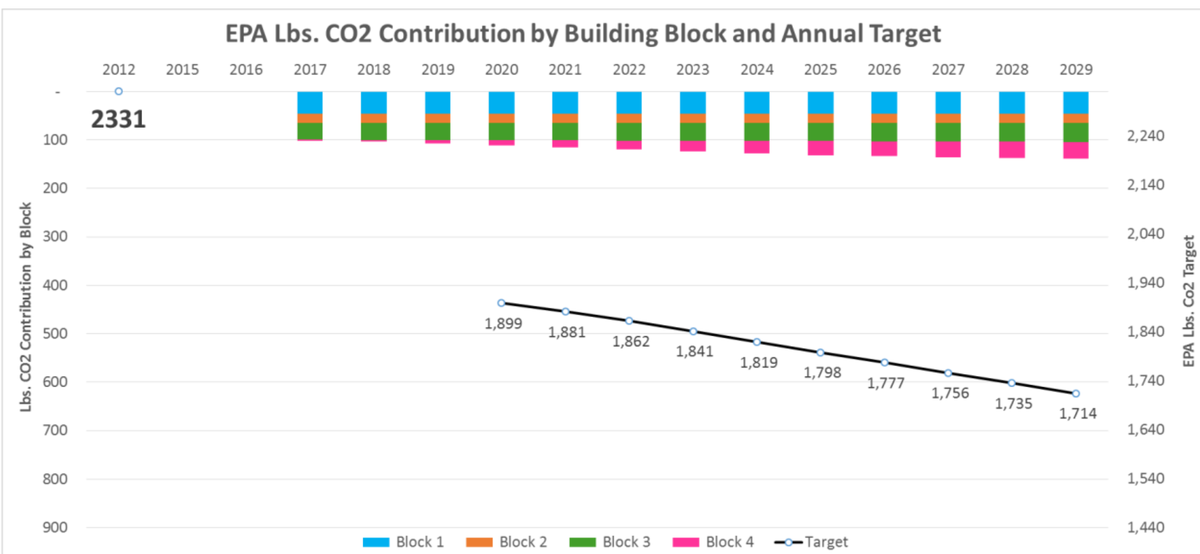
We will adjust Block 4 by reducing [1] the intrastate sales for Wyoming to 13,282,366 MWh; [2] EPA's annual .2% escalation of incremental annual savings to .1%; [3] the maximum incremental annual savings to .75%; and [4] the life of a portfolio measure to 10 years. This will reduce the cumulative savings in 2029 to 3.77%. We recognize that the .1% escalation and ultimate annual incremental savings of .75% would require active participation from rural utilities that have not to date embraced formal EE programs.

By making these changes, our comparative simulation looks like this:

	WY Simulation (lbs/MWh)	EPA Calcs (lbs/MWh)	
Step 1	2,331	2,331	2012 Fossil Fuel Emission Rate
Step 2	2,284	2,191	6% Heat Rate Improvement
Step 3a	2,284	2,191	Re-Dispatch Existing NGCC Capacity
Step 3b	**2,265**	2,151	Re-Dispatch Existing and Under Construction NGCC
Step 4a	2,265	2,151	Re-Dispatch Existing and Under Construction NGCC and Nuclear
Step 4b	2,226	1,771	Renewable Energy
Step 5	**2,192**	**1,714**	DSM/EE

2%	Plant Heat Rate Improvement (%)
907.0	CPGS lbs/MWh
95	Capacity Under Construction
758,211	Renewable Energy by 2030 (MWh)
3.77%	DSM/EE (MWh)
1.000%	Renewable Energy Growth Rate

The corresponding glide path to 2029 looks like this:



The EPA goal poses an enormous risk for the State: no solution may emerge, particularly between now and 2020, to close the enormous gap between the goal and the practical reality.

In that case, the simplest illustration of how stark the available options may be is to consider how many coal fired EGUs must be closed to reach the first goal, 1,899 lbs/MWh, and the final goal, 1,714 lbs/MWh. To do this, we first assume that if EPA ignores our analysis, it will credit Wyoming with the 2012 renewable generation that was exported, 3,702,896 MWh. The result is a Step 5 target of 2025 lbs/MWh.

Then we can eliminate both the carbon emissions and the megawatt hours for a facility, noting the result for Step 5. Although the Step 5 result is properly compared to the 2029 goal of 1714 lbs/MWh, the much flatter glide path of the state calculation provides a good sense of what will happen in 2020, the first compliance year.

We will eliminate the plants in order of scheduled full depreciation dates, as listed in our comment on Block 1, because this will minimize stranded investment. (This is not necessarily how the State would proceed, and it may not even be up the State, but we require an ordering principle.) Accordingly, the first premature closure would be Dave Johnston. The result can be seen in Step 5:

	WY Simulation (lbs/MWh)	EPA Calcs (lbs/MWh)	
Step 1	2,330	2,331	2012 Fossil Fuel Emission Rate
Step 2	2,284	2,191	6% Heat Rate Improvement
Step 3a	2,284	2,191	Re-Dispatch Existing NGCC Capacity
Step 3b	**2,263**	2,151	Re-Dispatch Existing and Under Construction NGCC
Step 4a	2,263	2,151	Re-Dispatch Existing and Under Construction NGCC and Nuclear
Step 4b	2,028	1,771	Renewable Energy
Step 5	**1,996**	**1,714**	DSM/EE

2%	Plant Heat Rate Improvement (%)
907.0	CPGS lbs/MWh
95	Capacity Under Construction
4,461,106	Renewable Energy by 2030 (MWh)
3.77%	DSM/EE (MWh)
1.000%	Renewable Energy Growth Rate

Current Coal Plants	**Sum of Carbon Dioxide (tons)**	**Sum of Net Energy Output (MWh)**	**Emission Rate (lb/MWh) - net energy**	**Emission Rate (lb/MWh) - after 6%**
WY TOTAL	**44,278,065**	**38,000,917**	**2,330**	**2,284**
Dave Johnston				
Dry Fork Station	3,555,713	3,093,371	2,299	**2,161**
Jim Bridger	14,994,886	13,625,135	2,201	**2,069**
Laramie River Station	13,324,303	10,997,853	2,423	**2,278**
Naughton	5,661,930	5,064,299	2,236	**2,102**
Neil Simpson II	780,568	568,601	2,746	**2,581**
Wygen 1	895,126	684,671	2,615	**2,458**
Wygen 2	745,459	587,832	2,536	**2,384**
Wygen III	1,004,748	855,131	2,350	**2,209**
Wyodak	3,315,332	2,524,024	2,627	**2,469**

Because we are eliminating substantial quantities from both the numerator and the denominator, the change is only from a rate of 2,025 lbs/MWh to 1,996 lbs/MWh. Our experience in discussing this matter with the public is that most people anticipate considerably more progress toward the goal from the closure of a plant.

If we next prematurely eliminate Naughton, the rate drops to 1,970 lbs/MWh.

If we prematurely eliminate the massive Jim Bridger plant, the rate drops to 1,867 lbs/MWh, presumably enough to clear the first glide path hurdle in 2020.

If we prematurely eliminate Wyodak, the rate drops to 1,731 lbs/MWh. This still falls short of the EPA goal for 2029.

By the time we get to the 2020 closures, however, there would be serious threats to regional reliability and a financial catastrophe for ratepayers. As we explained in our December 16, 2013, letter to Assistant Administrator McCabe, in 2020 the stranded investment for Dave Johnston will be $393,632,687; for Naughton, $326,213,892; for Jim Bridger, $524,351,740; for Wyodak, $248,714,883. In addition to the amounts listed at that time, Jim Bridger is undergoing investments in regional haze compliance which will add about $800 million of invested capital. Like the Laramie River Station, these investments should have a depreciable life of at least 20 years. The four plants are system assets, so Wyoming ratepayers would bear about 15.7% of those amounts. Since we believe such closures would have a wide economic impact and be accompanied by a broad impact on the coal industry, we also anticipate that there will be fewer ratepayers to shoulder these burdens, sending rates higher than the 15.7% would suggest.

None of these calculations include the cost of constructing replacement generation or purchasing replacement power.

The October 27 NODA requested comment on how book value may be used to address stranded investment concerns. We suggest that a binding plant closure order be deemed to count immediately toward a state target, but closure would be deferred until the end of a remaining useful life established by the closure order. So, if a binding closure order were issued for Dave Johnston in 2019, the compliance calculation for 2020 would eliminate that plant's emissions and megawatts, but the plant could continue to operate until the plant was fully depreciated in 2027 as provided in the closure order. We understand that this is not what EPA presently has in mind, but it incents a state to seek closure orders earlier rather than later, alleviates the devastating impact of premature closure on ratepayers, eliminates near term investment uncertainty, and facilitates planning for the benefit of the grid. We submit that EPA's proposed rule does none of those important things.

We have heard repeated suggestions that by cooperating with other states, costs and burdens could be shared and ameliorated. We reply that other states are not in the altruism business, and we do not expect them to be. In the absence of a fair and reasonable goal, there can and will be no cooperation.

We have heard repeated suggestions that Wyoming will have the flexibility to create solutions for the challenge of the EPA goal. We reply that flexibility will be of little use if the only building blocks presently identified pose an insuperable obstacle. After careful and, in some respects, exhaustive review of the documentation for EPA's goal, we have seen nothing that gives us confidence or even hope that goal can be met.

EPA might wish to consider what incentives this State, or any other, will have to assume responsibility for the Section 111(d) program if the only foreseeable result is catastrophe. We also see the risk that if the State fails in its effort to assume responsibility for the Section 111(d) program, EPA will claim broad enforcement powers under the guise of state law pertinent to the state plan.

The Commission respectfully requests EPA to adjust Wyoming's goal to a rate that poses a fair and reasonable challenge to comply.

Sincerely,

Alan B. Minier
Chairman

cc: Honorable Matthew H. Mead, Governor
Todd Parfitt, Director, Wyoming Department of Environmental Quality
Peter K. Michael, Wyoming Attorney General