Synapse
Energy Economics, Inc.

Environmental Controls and the WECC Coal Fleet

Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls.

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Introduction

The existing coal fleet in the US faces a broad array of environmental challenges, remedies for which may be realized by proposed and forthcoming environmental regulations. The Western Grid Group (WGG) asked Synapse Energy Economics (Synapse) to estimate the order in which existing coal plants in the Western Electricity Coordinating Council (WECC) might fall out of economic merit under existing and proposed environmental regulations. In answer to this request, Synapse created a database of 108 coal-fired generators in eleven (11) Western States which deliver power to the grid. In this database, we have used publicly available data sources to estimate the current (2008) cost of operating these units, and the rational forward-going costs of operating these units if various environmental controls are required in the fleet.

Current operating costs in the database include both fuel costs (the delivered price of coal to individual plants in 2008), as well as operating and maintenance costs. Additional forward going costs are estimated as the capital costs of new environmental controls, amortized, and recovered through power sales (using 2008 generation as a proxy), and the fixed and variable costs of operating these new environmental controls.

Background

In recent years, the EPA has announced a series of proposed and forthcoming regulations to control emissions of criteria pollutants and reduce damages to society and the environment from the electricity sector. Already enacted and now reaching enforcement deadlines, the BART rule (Best Available Retrofit Technologies) requires power plants which negatively impact visibility in public Class 1 lands (such as National Parks) to control of primary and secondary particulates, primarily through the application of new sulfur dioxide controls (SO_2). In 2010 the Clean Air Transport Rule (CATR) was proposed to replace the vacated CAIR (Clean Air Interstate Rule), and requires plants in 31 eastern states upwind of non-attainment areas to reduce secondary particulate and ozone-forming emissions, primarily NO_x and SO_2. In addition, in 2010, the EPA also announced that forthcoming rules would tightly control mercury emissions (known as the MACT, or Maximum Achievable Control Technology) and the use of water at once-through cooling power plants.

While the absolute depth of the forthcoming regulations are not yet known, several national-scale analyses have suggested that if the regulations are written tightly, a non-trivial fraction of the existing coal fleet might find it economically prudent to retire. The owners or investors of some coal plants in the existing coal fleet might find that recovering the capital expenditures required to meet environmental regulations renders their plant non-economic. In the face of increasing pressure for renewable energy and efficiency, and particularly (from an economic standpoint) as natural gas prices fall, there may be little justification for maintaining old, inefficient, and uncontrolled coal-fired power plants.

The analysis tool here, created for the Western Grid Group (WGG), estimates the relative economic merit of 108 coal generators in eleven western states (CA, OR, WA, WY, MT, ID, CO, UT, NV, AZ, NM). Economic merit is defined here as the absolute running and forward-going costs of a generator, on a per MWh basis, *relative to the cost of a viable replacement, such as a natural gas combined cycle unit*. The cost represents the value which would need to be recovered by a plant to cover its variable and fixed costs, as well as the costs of new capital improvements to meet environmental regulations. The replacement represents the decision which might be made by a rational utility – continue operating an increasingly expensive coal plant, or replace it with an alternate technology. The absolute economic merit is not considered in this analysis (i.e. if the coal plant outperforms a natural gas unit, or visa versa), instead, the cost of a natural gas CC unit is used as a generic benchmark and the economic merit order is taken into consideration.

The analysis does not include any analysis of sunk costs: i.e. the recovery of existing plant balances (the initial plant cost or any subsequent capital expenditures). There is little public information available to determine these balances, and this analysis assumes that utilities would make decisions on a rational forward-going basis.

2. Approach

The analysis compiles extensive data from the Energy Information Administration (EIA) to estimate operational characteristics of the coal fleet, and capital and O&M costs from several recent analyses of regulatory costs, including:

- An October 2010 assessment of the reliability impacts of EPA regulations from the National Electric Reliability Council (NERC)[1]
- Assumptions for the IPM v4.1 model in the EPA's Regulatory Impact Assessment (RIA) of the Clean Air Transport Rule (CATR)[2]
- Assumptions for the Charles River Associates (CRA) MRA-NEEMS model in the Eastern Interconnection Planning Collaborative (EIPC) assessment of the impact of EPA regulations.

Results from this analysis have been compared against both the specific and broad findings from other assessments of what might be termed "coal at-risk studies", including from Bernstein Research, the Brattle Group, Credit Suisse, and the assessments described above.

WECC Coal Fleet Running Costs: A 2008 Snapshot

We characterize, to the best extent feasible, the current running costs of each coal unit in the study region, based on publicly available data in 2008. The 108 units in this database reported an "operational" status in 2008, reported some degree of generation

[1] National Electric Reliability Council (NERC). October 2010. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.
[2] Documentation for EPA Base Case v.4.1.10. Chapter 5. Emission Control Technologies. Available online at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf

at the plant level, reported having burned coal as a primary, secondary, or tertiary fuel, and are not categorized by the EIA as co-generators.

The snapshot draws on information regarding efficiency (heat rate), capacity, generation and capacity factor, plant-scale coal fuel price, and estimated fixed and variable operations and management (O&M) costs.

Capacity, Generation and Capacity Factor

In this analysis, an estimate of the capacity and generation of each plant is critical to understanding how much capacity and generation is at stake or economically available for generation, and provides a crucial sense of how utilized each existing unit is today.

The nameplate capacity of each generating unit is taken as a fixed value;[3] generation is reported separately for each generator in this analysis.[4] In some cases, either reported generation or nameplate capacity is potentially erroneous due to generator upgrades beyond nameplate capacity: four generators report capacity factors above 95%.

Fuel Costs

To estimate fuel cost, we estimate each unit's coal consumption (in tons) and the heat content of that fuel (in mmBTU).[5] The EIA surveys a large number of plants to request information on coal contract terms, sources, and prices, and reports this information in EIA Form 423. Eighty-six (86, 80%) of the units in this analysis reported their delivered fuel prices for 2008.[6] For units at these plants which report the delivered coal price, the unit price of coal can be estimated directly.

For units in which the overall plant has not reported the price of coal to the EIA, we find the amount of each type of coal the plant has burned (including bituminous, subituminous, lignite, waste coal, and syncoal),[7] and assume that this fraction remains constant over all units in the plant. The price of each type of coal is taken from a lookup table derived from EIA Form 423. If the unit of interest is in a state where another plant reported a delivered coal price (of the specific type), this price is used to estimate the price at the unit. Where a state price is unavailable, the analysis uses a regional price,[8] and finally a national price if no regional price is available. This search is conducted for each coal type; the aggregate fuel price compiled from the various coal uses at the unit.

Operations and Maintenance (O&M) Costs

Operations and maintenance (O&M) costs include the costs of maintaining structures, boilers, and generators, the costs of replacing and repairing worn components, costs paid for coolants and sorbents, the disposal costs for ash and cooling blowdown, as well

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[3] EIA Form 861, Generator. 2008
[4] EIA Form 923, Form 5A. 2008
[5] EIA Form 423, 2008
[6] EIA Form 423, 2008
[7] EIA Form 923, 2008
[8] Based on AEO 2010 Coal Regions

as employee salaries. There is very little public data available on these costs for existing generators, usually only available through specific rate-cases.

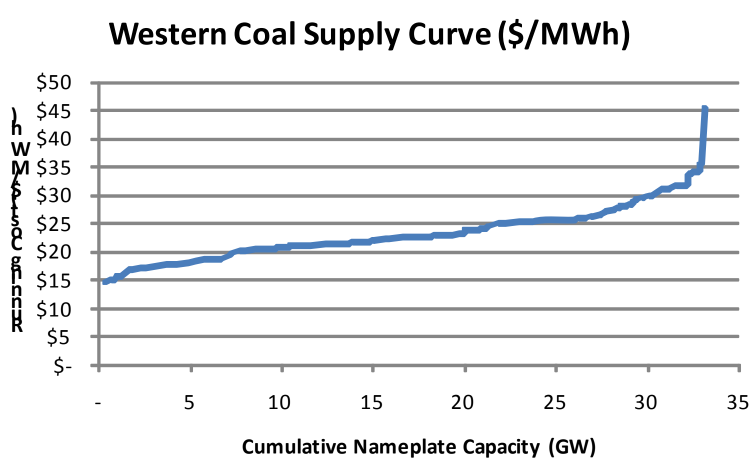
In this analysis, we use assumptions from the NERC 2010 Reliability Assessment to estimate fixed and variable O&M costs.[9] Costs are categorized with economies of scale based on the capacity of the plant. Assumed O&M costs are given in **Table 1,** below.

Table 1. Assumed O&M Costs

Fixed and Variable O&M Assumptions (2010$)		
NERC EPA Analysis 2010 Assumptions		
MW	**Coal Fixed O&M ($/kw-yr)**	
0	$	30.0
100	$	21.0
300	$	18.0
MW	**Coal Variable O&M ($/MWh)**	
0	$	5.0
100	$	4.0
300	$	3.8

Running Costs for Existing Coal Units

The total running cost for existing coal units is estimated as the sum of the fuel cost and the fixed and variable O&M costs, expressed in $/MWh. **Figure 1**, below, compiles the entirety of the coal fleet into a generic supply curve for the 2008 coal fleet, expressed by total capacity available at particular price points. A majority of the existing coal fleet costs between $20 and $40 per MWh, with a small number of units showing costs well above $50 per MWh.



[9] National Electric Reliability Council (NERC). October 2010. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.

Figure 1. Estimated running cost for Western coal supply curve for 2008; note that these values *do not include* regular capital expenditures or additions, or remaining plant balances.

It should be noted that the costs shown in **Figure 1** do not include regular capital expenditures, such as system upgrades or major component replacements, or payments on initial capital expenditures. In addition, these costs do not include CO_2 prices, or other emissions payments for sulfur dioxide (SO_2), mercury, or oxides of nitrogen (NO_X) in applicable trading regions.

B. New Environmental Control Costs for the Western Coal Fleet

EPA regulations are expected to result in an increase plants installing emissions control technologies for SO_2, NO_X, and mercury, as well as water withdrawal reduction measures at some plants which use once-through cooling.

The WGG database estimates the incremental forward costs of adding environmental controls to the existing western coal fleet, where appropriate controls are not already available. These costs are categorized as an initial capital expenditure amortized over a period, and the fixed and variable O&M costs of operating the new equipment.

The user of the database is given the opportunity to select which types of control technologies would be required under a stricter regulatory environment. The choices include:

- FGD (flue gas desulfurization) for SO_2 control and supplementary mercury capture
- SCR (selective catalytic reduction) for NO_x control
- ACI (activated carbon injection) for mercury control
- Baghouse for particulate capture, and
- Wet cooling tower to reduce water withdrawals

Financial Assumptions

In this analysis, we follow generic financial assumptions in the NERC analysis.[10] The NERC study lays out four categories of ownership and estimated cost of capital recovery factor (CRF) assumptions as in **Table 2**, below.

Table 2. Assumed capital recovery factors for environmental upgrades.

Capital Recovery Factor (CRF) Assumptions		
	Environmental Upgrades	New Plant

[10] National Electric Reliability Council (NERC). October 2010. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.

	Pre-Tax Cost of Capital	15 Year Book Life	Capital Recovery Factor (CRF)	30 Year Book Life	Capital Recovery Factor (CRF)
Merchant	17.5%	15	19.2%	30	17.6%
Regulated IOU	12.7%	15	15.2%	30	13.1%
Cooperative	7.0%	15	11.0%	30	8.1%
Municipal	6.0%	15	10.3%	30	7.3%

We assume that environmental upgrades are amortized over a 15 year period, yielding CRF of 10.3% - 19.2% as in the table.

Unit ownership and regulatory status are derived from EIA Forms 860 and 861 (owner as a regulated load distribution company [LDC], and regulatory status, respectively). We examine the ownership of the first listed owner in the EIA database. Plants in which the owner is non-regulated and also not an LDC are assumed to be non-regulated merchant plants. Municipal and cooperative owners are identified directly from EIA Form 860 data. All other regulated entities, listed or unlisted as LDCs, are assumed to be regulated IOUs.

FGD Assumptions

Specific units are determined to already have a valid and operational sulfur control mechanism if the generator's primary boiler is reported to have an operational FGD (in 2008) of a type listed as "adequate" in **Table 3**, below.

Units with existing FGD were evaluated to determine if the type of FGD is adequate. Based on information presented in EIA Form 860 FGD, we compiled the removal efficiency of eight different types of reported FGD units. Based on this information, we determined that "Mechanically Aided" and "Venture Type" FGD (see **Table 3**) would be inadequate to comply with EPA regulations.

Table 3. FGD removal efficiency

FGD Type	Average Removal Efficiency	Designation in Economic Triage
Jet Bubbling Reactor	94%	Adequate
Circulating Dry Scrubber	82%	Adequate
Mechanically aided type	**56%**	**Inadequate**
Packed type	78%	Adequate
Spray dryer type	85%	Adequate
Spray type	89%	Adequate
Tray type	89%	Adequate
Venture type	**71%**	**Inadequate**

In this analysis, 47 of 108 units are found to have inadequate FGD.

We follow FGD cost assumptions as derived explicitly in the EPA IPM 4.1 model, as stipulated by an associated Sargent & Lundy LLC analysis.[11] The assumptions derive capital and O&M costs based on primarily capacity, but also unit heat rates, specifications on targeted emissions rates, and the cost of reagents and components. We use listed default values for component costs and labor charges (**Table 4**). We do, however, modify the input uncontrolled SO_2 rate to 1.5 lbs/MMBtu, reflecting an emissions rate more indicative of PRB coal.

Table 4. FGD Cost Assumed Variables

Variable	Value
SO2 Rate (lbs/MWh)	1.5
Labor Rate ($/hr)	$60
Limestone cost ($/ton)	$15
Waste disposal cost ($/ton)	$30
Auxillary Power Cost ($/kWh)	$0.06
Makeup water cost ($/1000 gal)	$1.00

The makeup water cost of $1/1000 gallons equals a cost of approximately $325/acre-foot, which could be considered low for some Western states (previous research has suggested wholesale transaction costs averaging $600/AF and as high as $5000/AF), but is a reasonable first-pass proxy under non-drought conditions. This value does not make a significant difference in the O&M costs associated with FGD units.

We assume a cost “retrofit factor” of 1.0 for FGD units. This factor is simply a multiplier for capital expenditures.

Units with pre-existing FGD are assumed to operate at 100% utilization, which, in this analysis, increases their fixed and variable O&M costs.

SCR Assumptions

To estimate the added cost to the existing coal fleet for selective catalytic reduction (SCR), we first identify units in which the primary boiler had appropriate NO_x controls in 2008. Characterization of NO_x controls as listed with the EIA are given in **Table 5**.

Table 5. NOx control strategies considered adequate

Definition	NOx Control Adequate
Advanced Overfire Air	Inadequate
Biased Firing (alternative burners)	Inadequate
Fluidized Bed Combustor	Inadequate
Flue Gas Recirculation	Inadequate
Fuel Reburning	Inadequate
Low Excess Air	Inadequate
Low NOx Burner	Inadequate

[11] Sergent and Lundy, 2010. IPM Model – Revisions to Cost and Performance for APC Technologies. Wet FGD Cost Development Methodology. Appendix 5.1a August 2010. Available online at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51A.pdf

No change in historic operation of unit anticipated	Inadequate
Not determined at this time	Inadequate
Overfire Air	Inadequate
Repower Unit	Inadequate
Slagging	Inadequate
Selective Noncatalytic Reduction	**Adequate**
Selective Catalytic Reduction	**Adequate**
Decrease utilization - rely on energy conservation and/or improved efficiency	Inadequate
Other (specify in SCHEDULE 7, COMMENTS)	Inadequate

Only existing SCR and SNCR units are considered adequate; all units practicing other non-adequate NO_x control strategies are given forward-going costs associated with new SCR. One hundred and three (103) of 108 units in the west are not equipped with SCR as of 2008.

We follow SCR cost assumptions as derived explicitly in the EPA IPM 4.1 model, as stipulated by an associated Sargent & Lundy LLC analysis.[12] The assumptions derive capital and O&M costs based on capacity, unit heat rate, and specifications on targeted emissions rates, as well as the cost of reagents and components. We use listed default values for component costs and labor charges (**Table 6**).

Table 6. SCR Cost Assumed Variables

Variable	Value
Nox Removal Factor	88%
NOx Rate	21%
NOx Removal Efficiency	70%
Urea Cost ($/ton)	310.0
Steam Cost ($/klb)	4.0

We assume a cost "retrofit factor" of 1.0 for SCR units. This factor is simply a multiplier for capital expenditures.

Units with pre-existing SCR are assumed to operate at 100% utilization, which, in this analysis, increases their fixed and variable O&M costs.

ACI and Baghouse Assumptions

We assumed that units with existing ACI would not need to invest in new ACI; similarly, units with existing fabric-filter baghouses would not need new particulate controls. Following the method laid out for FGD and SCR, we associated each unit with a primary boiler, and queried for appropriate ACI. Units where the boiler listed "ACJ" (Activated Carbon Injection System) in Form 860, Schedule 6 were deemed adequate. All others require ACI. Boilers equipped with some form of baghouse (shake and deflate, pulse, or reverse air) were considered appropriate technologies, all others require new baghouses.

[12] Sergent and Lundy, 2010. IPM Model – Revisions to Cost and Performance for APC Technologies. SCR Cost Development Methodology. Appendix 5.2a. August 2010. Available online at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf

Of the 108 units in the analysis, only 4 are equipped with ACI and 51 have particulate controls (as of 2008).

Costs for ACI and Baghouses were taken from the EIPC 2010 assumptions[13], which are, in turn, based on cost estimates in state testimony.[14] Similarly to FGD and SCR assumptions, the costs are broadly a function of the unit capacity (see functions in **Table 7**).

Table 7. Costs assumption curves for ACI and Baghouses

ACI	Function
Capital Cost ($/kW)	y = 1237.4 * MW ^ -0.846
Fixed O&M ($/kW-yr)	y = 68.02 * MW ^ -0.894
Variable O&M ($/kW-yr)	0.37
Baghouse	**Function**
Capital Cost ($/kW)	y = 3071.7 * MW ^ -0.4999
Fixed O&M ($/kW-yr)	y = 15.174 * MW ^ -0.584
Variable O&M ($/kW-yr)	0

Costs for Reducing Water Withdrawals under CWA §316(b)

Section 316(b) of the Clean Water Act "require[s] that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." In 2004, the EPA promulgated the Cooling Water Intake Structures – CWA 316(b) Phase II rule to comply with the CWA. The rule required that "large existing power plants … meet performance standards to reduce the number of organisms pinned against parts of the cooling water intake structure by 80 to 95 percent."[15]

This analysis finds that approximately 18 of 108 units used some form of once-through cooling (OTC) in which river, lake, or ocean waters are used directly to cool boilers. For many power plants, the only feasible mechanism to comply with the purpose of the ruling would be to abandon OTC and install wet-cooling towers, which have much smaller withdrawals, and therefore impinge far fewer organisms.

The Electric Power Research Institute (ERRI) recently published estimated costs of cooling technologies, estimating that the "average" wet cooling tower cost approximately $176 per kW (2008$). This value is approximately consistent with research conducted at Synapse on the control costs of wet cooling technology.

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[13] Eastern Interconnection Planning Cooperative (EIPC), 2010. Working Draft of MRN-NEEM Modeling Assumptions and Data Sources for EIPC Capacity Expansion Modeling. Prepared by Charles River Associates. December 22, 2010. http://www.eipconline.com/uploads/MRN-NEEM_Assumptions_Document_Draft_12-22-10.pdf

[14] Cichanowicz, J Edward, 2006. "Testimony of J E Cichanowicz to the Illinois Pollution Control Board. A Review of the Status of Mercury Control Technology." July, 28, 2006.

[15] EPA., 2004. National Standards Announced for Cooling Water Intake Structures at Large Existing Power Plants. Press Release. http://yosemite.epa.gov/opa/admpress.nsf/b1ab9f485b098972852562e7004dc686/b66b955940239d9185256e3d005a76e6?OpenDocument

The NERC analysis of the cost of complying with EPA regulations assumes economies of scale associated with the capital cost of installing a wet cooling tower. The assumed NERC cost curve, used in this analysis, is given in Figure 2. Points on this curve are given at 30 MW capacity increments; units with capacities between increments are rounded to the next highest cost and units below the minimum (30 MW) are given the highest listed cost ($665/kW)

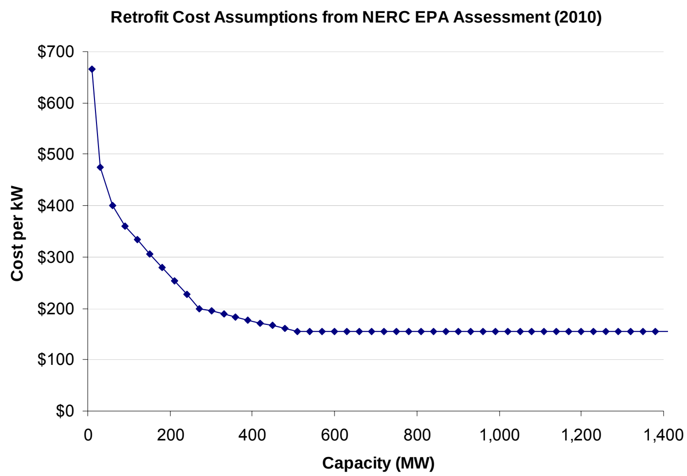

Figure 2. NERC cost curve for wet cooling towers.

For this analysis, we use variable O&M costs as given by an independent source, approximated at $2.9/MWh.[16]

Natural Gas Replacement Assumptions

We assume that each coal unit's economic merit might be compared against a "replacement" technology. The replacement, in this case, is considered to be either a new natural gas CC unit, or an existing natural gas CC unit, running at the same capacity factor as the coal unit. New units the capital cost of the natural gas unit, amortized over a 30 year period (using the same CRF assumptions seen in **Table 2,** above), while existing units only account for fuel costs, as well as fixed and variable O&M costs.

The cost assumptions for this analysis are taken from the EIA's Annual Energy Outlook (AEO), 2010.[17] We use operating cost assumptions for new gas CC units. The "expected" fuel price tracks the levelized cost of AEO's natural gas forecast from 2015 through 2034.

[16] Powers, 2003. 316(b) Phase II Closed-Cycle Retrofit Options: Feasibility and Cost
[17] EIA, 2010. Annual Energy Outlook. Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.