Synapse
Energy Economics, Inc.

TVA Coal in Crisis

Using Energy Efficiency to Replace TVA's Highly Non-Economic Coal Units

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1. Executive Summary

The Tennessee Valley Authority (TVA) has a historic opportunity to lower consumer bills and improve public health in its region by moving away from its aging fleet of poorly-controlled coal-fired power plants. With the completion of a TVA-funded study on energy efficiency in the region in December 2011, it has become clear that efficiency offers a path forward that can help TVA offset some of the nearly $12 billion in capital expenses, and billions more in operating expenses for decades, that would otherwise be required to bring its coal plants up to modern public health standards.

TVA must move quickly to seize these opportunities because pressing public health requirements will require clean-ups at its coal plants within the next three to four years. Our analysis demonstrates that the massive retrofits required for these clean-ups do not make economic sense: a substantial fraction of TVA"s coal capacity – about 64% - are more expensive to retrofit and operate than simply buying power off the market. Rather than passing on billions in expenses to ratepayers to keep these plants online, TVA should be exploring ways to retire these non-economic plants as quickly as possible.

TVA's own efficiency study – which was not available when TVA conducted its most recent integrated resource planning (IRP) process – demonstrates that there is a better way. Energy efficiency can rapidly produce hundreds or thousands of megawatts in savings, savings which are sufficient to replace capacity requirements now met by many of TVA's coal units in time to meet public health deadlines. Specifically, if TVA simply committed to the 1.2% annual savings rate which its study identifies as achievable, it could save 1,590 MW of capacity by 2015, which is more than sufficient to replace the capacity of either its Gallatin, Allen, or Colbert plants, or the units now being considered for retrofits at its Shawnee and John Sevier plants. Taking that course and retiring any of those plants rather than retrofitting them would produce major savings. Replacing Gallatin, for instance, could save at least $2.7 billion by 2032, based on TVA's own conservative assumptions about the cost of energy efficiency, and cut residential ratepayer bills by at least $2.00 per month for several decades.

If TVA were to match leading national utilities and move to incremental efficiency savings to 2% per year it could do even better. TVA could replace two non-economic plants, saving between $7.3 to $10.6 billion between 2012 and 2032, and cutting the cost of supplying equivalent capacity and energy by half or more.[1] Instead of residential bills rising by 4.5% (about $8 per month in 2016) just to retrofit and maintain these units, we would expect residential bills hold steady or fall, even while TVA meets all applicable environmental compliance obligations.

Continuing to push for deeper efficiency even after 2016 will result in significant savings for consumers, and allow for the retirement of other aging coal units, especially if paired with investments in other forms of cleaner energy.

TVA is charged with providing low cost energy to customers in its region. It aspires to lead the nation in improving air quality, and to lead the Southeast in energy efficiency, and providing low-cost service to

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[1] Present value. Difference between coal retrofit scenario for Gallatin, Colbert, and John Sevier 3 ($12.6 w/o CO2 price and $15.9 billion with $21/t$CO_2$ levelized CO_2 price) and "Synapse Aggressive" efficiency scenario of 2% incremental EE per year ($5.3 billion). This valuation assumes that energy efficiency is employed <u>only</u> to replace non-economic coal units, and is not extended beyond 2016, even if highly cost-effective to do so.

ratepayers. TVA can and should aspire to become such a leader, but to do so TVA must quickly and transparently acknowledge the dire forward-going economic condition of its coal fleet and begin rapidly planning to close its non-economic units, replacing them with energy efficiency and cleaner power.

2. Introduction

Like the US fleet in general, the TVA coal fleet's future is increasingly tenuous. Aging facilities, the finalization of long-delayed public health and environmental rules, falling natural gas prices, flattening or falling load requirements, and continuing pressure to reduce CO_2 emissions all serve to reduce the profit margins coal plants have traditionally enjoyed. Utilities across the country increasingly are deciding to retire plants and replace them with cleaner, and cheaper, energy. TVA now must decide whether to do the same.

The TVA fleet may be more poorly positioned than other utilities, making the wisdom of retiring non-economic coal plants all the clearer: the coal fleet is older than the rest of the US coal fleet[2] and operates at a lower capacity factor.[3] The TVA fleet is also one of the least controlled single-owner fleets in the country. Out of the 39 operating coal units in the fleet not already slated for retirement or idling,[4] only a few have state-of-the-art emissions controls (17 units have SO_2 controls; 20 units have some form of NOx controls).

Of these 39 remaining coal units, we estimate that 33 units, representing 8,570 MW of nameplate capacity, are deeply non-economic on a going-forward basis. In general, these are units wherein the anticipated forward-going cost of operating, retrofitting, and maintaining these units exceeds the cost of replacement with either new natural gas generation or simply with energy purchased from wholesale markets. The remaining six units not currently slated for retirement are, at best, marginal.

TVA must decide soon whether to retire or retrofit these units. In addition to impending regulatory deadlines, a consent decree with EPA and public interest groups requires TVA to make these decisions within the next two to three years for units at its Allen, Gallatin, Colbert, and Shawnee plants, all of which lack modern controls. If it disregards the failing economic condition of its coal fleet, and doubles-down with retrofit spending, TVA could be committing to nearly $12 billion in capital retrofits to bring those aging plants that are not retiring up to modern public health standards. This is not a wise course.

Energy efficiency measures could entirely replace the capacity now supplied by many of TVA's least economic coal units. For example the Gallatin plant could be replaced by energy efficiency prior to 2016 saving at least $2.7 billion dollars from 2016-2032,[5] rather than expending the $1.1 billion in capital costs

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[2] The US coal fleet is, on average 39 years old (weighted by capacity); by the same measure, the TVA fleet is about 50 years old.

[3] US (weighted avg. by capacity) = 64% between 2008 and 2010; TVA = 54%.

[4] The TVA coal fleet consists of 63 units, some of which are either retired or idled, or slated for retirement via a consent decree with EPA and public interest groups . Excluding these 24 units, the fleet has 39 units open for consideration of retirement or retrofit to meet environmental regulations.

[5] Savings are net of present value for cost of energy efficiency at a constant 1,600 MW (7,500 GWh per year building from zero in 2012 to 1,600 MW in 2016, and held at that level through 2032). According to TVA's EE cost estimates presented in a Global Energy Partners study, the cost of this trajectory would be about $3.0 billion over 17 years (present value). The cost of retrofitting and then maintaining Gallatin from 2016 (replacement year) through 2032 is approximated at a total cost of $5.7 billion without a CO_2 cost. Difference is approximately $2.7 billion of savings. With a moderate price on CO_2 the cost of maintaining Gallatin could be $7.4 billion, resulting in $4.4 billion of present value savings to use EE instead of a retrofit.

expected to be incurred in the next four years at Gallatin alone.[6] Indeed, pursuing just 1.2% in energy savings each year would allow TVA to reduce demand by 1,590 MW, allowing it to entirely replace the whole of Gallatin, Allen, or Colbert prior to 2016. Further ramping up efficiency programs to 2% incremental savings each year would allow TVA to replace about 2,750 MW by 2016 - the equivalent capacity of Gallatin, Colbert, and John Sevier 3. This course would save ratepayers at least $6.6 billion from 2016-2032.[7] Residential customers could expect to see nearly a $6 hike in monthly bills just to retrofit these three plants, but would see a drop in bills by about a dollar per month pursuing aggressive efficiency instead.

The exceptional consumer and utility savings available from energy efficiency provides a strong rationale for retiring, rather than retrofitting, as many of TVA's non-economic coal units as feasible. By opting to retire, rather than retrofit, the worst of the fleet, TVA has a narrow, but powerful, window of opportunity. TVA can upgrade from its dependency on aging coal units to resilient energy efficiency and demand response, local and regional renewable energy resources, and other generation options.

A. TVA's Responsibility to Ratepayers

Utility commissions across the US are considering coal retrofit versus retirement decisions as it becomes clearer that older existing coal units are not economic to retrofit. State utility commissions are charged with balancing ratepayer financial interests with utility requirements, ideally incentivizing public utilities to act as competitive enterprises, rather than monopolies. In the case of existing generating units, utilities and state utility commissions are increasingly determining that, where additional investments in aging generation assets renders them more expensive than other reasonable alternatives, the units should not receive additional investments. If such investments are required to keep the units operational, then units should be shuttered if it is not economic to retrofit. For example, in Kentucky, two large utilities have recently chosen to withdraw applications to retrofit large, aging coal units when faced with the reality of failing economics.[8] Across the country, dozens of GW of coal units have announced certain retirement over the last two years.

As a federal entity, TVA is not regulated by state utility commissions. However, TVA must still act in the best interest of its customers and ratepayers. From its first power project at Muscle Shoals forward, TVA has been charged with providing power "for the benefit of the people of the [region] as a whole" on an economic basis and at "the lowest possible rates."[9] To meet this charge, TVA is to employ a least-cost planning program.[10] As we discuss in more detail below, TVA's most recent round of planning did not fully take advantage of energy efficiency, and so has not put the utility on a course towards low cost power for its customers. Before committing to expensive coal retrofits which will increase bills for years, TVA needs to reevaluate its choices.

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[6] See p. 9 of the TVA Board of Directors Minutes Meeting, August 18, 2011.

[7] Savings are net of present value for cost of energy efficiency at a constant 2,750 MW (12,400 GWh per year building from zero in 2012 to 2,750 MW in 2016, and held at that level through 2032) a total cost of $6.0 billion, versus cost of retrofitting and then maintaining Gallatin, Colbert, and JS3 from 2016 (replacement year) through 2032, a total cost of $12.6 billion without a CO_2 cost. Difference is approximately $6.6 billion of savings. . With a moderate price on CO_2 the cost of maintaining these units could be $15.9 billion, resulting in $9.9 billion of present value savings to use EE instead of a retrofit.

[8] AEP, Big Sandy: http://www.statejournal.com/story/18661016/aep-drops-plan-to-install-scrubber-on-ky-big-sandy-power-plant. KU&LG&E, E.W. Brown. http://migration.kentucky.gov/Newsroom/psc/pscpr12-15-2011.htm

[9] 16 U.S.C. §831j.

[10] *See* 16 U.S.C. § 831m-1.

In order to help clarify a path for TVA, this paper examines the forward-looking economics of the TVA coal fleet in light of rising capital requirements, falling gas prices, and reasonable expectations for carbon prices. This paper:

- briefly examines the environmental regulations facing the US coal fleet and TVA;
- proposes a simple retrofit / retire economic merit framework;
- demonstrates that the TVA coal fleet is largely non-economic on a forward-going basis;
- estimates the ability for demand-side management programs to avoid high-cost investments at aging coal units; and
- makes a case for comprehensive and objective fleet wide planning.

B. The Pressing Need to Clean Up the TVA Coal Fleet

Coal-fired power plants are among the largest sources of air and water pollution in the country, and as a result they pose a significant public health threat. To address these risks, the Clean Air Act and Clean Water Act have long required the fleet to install pollution control technology. The full suite of upgrades needed to comply with the law have, however, been delayed (often by industry litigation) and so are only now falling into place, often decades after they were originally developed. The combination of these national compliance obligations and TVA-specific control requirements is driving major clean-up responsibilities for TVA's aging fleet. In light of these obligations, TVA must decide whether to decisively move away from further liabilities associated with coal, or to invest in costly retrofits to keep its coal plants online.

As an initial matter, TVA must comply with a settlement requiring clean-ups at many of its coal-fired power plants by specific dates for each plant and control technology. In 2011, TVA entered into a consent decree ("CD") with four states (Alabama, Kentucky, North Carolina, and Tennessee) and three environmental groups (National Parks Conservation Association, Sierra Club, and Our Children's Earth Foundation) requiring significant reductions of certain pollutants from TVA's coal-fired electric generating fleet. Among other requirements, the CD requires TVA to fit units at its Allen, Gallatin, Colbert, and Shawnee plants with SO_2 and NO_x controls between 2016 and 2018 if it does not retire these units (or, in some cases, remove them from service or repower them to biomass). Because TVA must announce its decisions on these units at least three years in advance, TVA is facing a rapidly approaching 2013 deadline to determine its compliance pathway for many of these units.

The CD, however, is not the only requirement faced by the TVA. Several regulations with significant cost implications have been promulgated and proposed by the EPA, and still others are expected in the near future. The Mercury and Air Toxics Emissions Standards (MATS), Cross-State Air Pollution Rule (CSAPR), tightening National Ambient Air Quality Standards (NAAQS) for sulfur dioxide, particulate matter (PM) and ozone, rules governing the disposal of Coal Combustion Residuals (CCR) and water wastes (effluent limits), as well as rules protecting rivers by reducing fish kills at cooling intakes, and rules governing carbon pollution from existing coal plants are all expected to impart significant capital and operating costs on existing coal generators. It is thus likely that the combination of the consent decree, MATS, CSAPR, and emerging NAAQS will require significant control upgrades across the fleet, and the other rules (CCR, effluent limits, water intake, and carbon limits) will impose significant capital and operational costs at TVA.

As a result of these impending costs for pollution controls, TVA and other utilities must determine whether ratepayers are better served by retrofitting existing coal units to comply with environmental regulations, or whether the plants should be retired in favor of more economic alternatives. Numerous utilities are now in the process of considering the merits of coal unit retirement as a mechanism to meet environmental obligations while adhering to least-cost principles: if a unit can be retired before an environmental compliance deadline, then there is no need to invest in environmental controls, saving ratepayers hundreds of millions to billions of dollars at each unit while producing environmental benefits.

3. Retrofitting Most of TVA's Coal Fleet Does Not Make Economic Sense

To better illuminate the choices before TVA, Synapse has analyzed the economics of TVA's remaining 39 coal-fired units under several different scenarios. Using publicly available data, we begin by considering the economics of the coal fleet given TVA's CD compliance obligations. Even under this limited scenario, much of TVA's coal capacity is marginal to non-economic. We then add in the costs TVA would face if it retrofitted its plant to comply with all the public health and environmental rules which it now faces, with the exception of carbon pollution controls. Under that more realistic scenario, almost half the units in the fleet are distinctly non-economic, including nearly all of the units at the Gallatin, Allen, Colbert, and Shawnee plants. Finally, we add in the costs of CO_2 controls, as will very likely be imposed within the decade. Even with a modest carbon cost, nearly *two-thirds* (64%) of TVA's coal capacity is non-economic, and the few remaining units should be considered marginal, at best.

This analysis reveals how irrational it would be for TVA to invest billions in retrofitting its fleet. TVA has significantly lower-cost options, including, principally, energy efficiency which will allow it to save billions, pass those savings onto ratepayers, all while sharply reducing the air and water pollution to which ratepayers would otherwise be exposed.

A. Forward-Going Costs at TVA

Our TVA analysis is based on several years of work. In January of 2011, Synapse performed an economic analysis for the Western Grid Group (WGG), examining the rough costs and economic merit of retrofitting each coal unit in the Western Electricity Coordinating Council (WECC) with advanced SO_2 controls (wet flue gas desulfurization, or FGD), NOx controls (selective catalytic reduction, or SCR), PM controls (baghouses), and cooling towers at open-cycle cooled units.[11] The analysis estimated the forward-going cost of retrofitting and operating each coal unit in the region against alternative options. Results of this analysis were used by WECC to evaluate how efficiency and renewable could be used to reduce CO_2 emissions in the West.[12] A technical description of the WGG analysis is provided in Appendix A.

[11] WECC Coal Plant Retirement Based on Forward-Going Economic Merit. January, 2010. Prepared for Western Grid Group. Available online at http://www.synapse-energy.com/Downloads/SynapseReport.2011-01.EF+WGG.WGG-Coal-Plant-Database.10-077-Presentation.pdf

[12] WECC. March 10, 2011. Western Grid Group's Carbon Reduction Case. Available online at http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/10March2011/Lists/Presentations/1/WGG%20Carbon%20Reduction%20Study%20Case.pdf

Synapse replicated this analysis structure for TVA to estimate the economic merit of retrofitting and continuing to operate each coal unit in the TVA fleet, updating assumptions and adding new information as available. Using public data regarding sources on which controls are already in place, the cost of new environmental controls, and the estimated current cost of generation, we estimate a “forward-going” cost of generation – essentially, a levelized present value revenue requirement. This value can be compared against alternatives, such as the cost of market purchases, energy efficiency, or renewable energy options to yield a sense of which units should be considered for replacement or repowering.

For the purposes of a forward-looking analysis, we consider forward-going costs to include the following elements:

- Fuel [13]
- Variable and fixed operations and maintenance (O&M)
- Emissions[14]
- New capital for environmental equipment [15]
- New environmental controls O&M.

B. Compliance Scenarios

For purposes of this analysis, we examined the forward-going costs of operating the coal fleet under three compliance scenarios. These three scenarios represent a continuum of increasing stringency of new controls and emissions costs, beginning with the limited set of controls required by the CD itself, then layering on controls required under pending pollution rules, and, finally, considering the implication of moderate costs for carbon dioxide. The scenarios are:

1. **Consent Decree Only.** This scenario estimates the minimum required retrofit costs according to the terms of the TVA consent decree, without taking into account other existing, proposed, and emerging EPA regulations. This scenario approximates our impression of the controls TVA accounted for in its 2011 IRP; it includes limited FGD, SCR, and particulate controls.
2. **All EPA Rules, No CO_2 Price.** In this scenario, we assume that long-term compliance with CSPAPR, MATS, PM, ozone and SO_2 NAAQS will ultimately require comprehensive controls at all TVA units, including FGD, SCR, baghouses, and activated carbon injection (ACI). In addition, we assume that the water intake rule will require closed-cycle cooling, the CCR rule will be implemented at a stringent level (“subtitle C” for a hazardous waste designation), and that the pending effluent limitation guidelines will require water treatment facilities scaled to treat CCR and

[13] Due to the highly localized nature of coal transactions, we also (conservatively) leave coal prices flat in real terms.
[14] We included only carbon dioxide costs for this emissions costs analysis; controls for other pollutants are included in the capital and O&M costs. We assume that a utility will, under all circumstances, meet its obligations under CSAPR, and will not be required to purchase additional allowances of SO_2 or NOx.
[15] We do not include ongoing capital expenditures (i.e. boiler and turbine replacements and other major non-environmental capital).

FGD waste.[16] This scenario is designed to demonstrate economic merit without the added weight of a CO_2 pricing scheme, and therefore this scenario has no CO_2 price.

3. **All EPA Rules, Mid-Range CO_2 Price.** This scenario is identical to Scenario 2 with the addition of a mid-range CO_2 price adder; the adder of $21/ton represents the real levelized price of an increasing cost trajectory starting at $15 in 2018 and $50 in 2030.

Having generated these controls costs, in order to evaluate a basic level of economic merit we examined the forward-going cost of coal generation against a conservative levelized estimate of long-run market prices. Long-run market prices approximate the revenues that could be commanded by a generator if the unit were in an open market. For simplicity, we assume that long-run build margin is approximately the all-in cost of a new natural gas combined cycle (NGCC) unit, including any incumbent CO_2 costs as required. In addition, we compare the forward-going cost of coal against recent market prices in PJM and MISO, energy efficiency,[17] and selected renewable energy options.

Because long-run market prices are assumed to equilibrate at the all-in cost of a NGCC, we examine uncertainty in natural gas prices to characterize coal generation's economic merit. We use a baseline price based on the EIA Annual Energy Outlook (AEO) 2012 trajectory (published June 2012) but we also examine natural gas prices 33% above and below this trajectory.

Comparing the costs of operating the plants under our compliance scenarios with market prices allowed us to sort TVA's coal units into three economic classes, as follows:

- N**on-economic units:** Coal units that are more expensive than even the highest long-term levelized market price[18] are considered non-economic. TVA should be planning today for the retirement of these units prior to the 2015 MATS deadline.[19]
- **Marginal coal units:** Coal units that are more expensive than the lowest long-term levelized market price but less expensive than the highest cost future are effectively marginal relative to the market; TVA should carefully examine environmental requirements at these units and, if choosing to retrofit, demonstrate decisively that these units will remain economic relative to all other reasonable options. Other utilities have found that many of these units, particularly those more expensive than baseline gas costs, are too high risk for continued investment, and are currently reviewing options to repower or retire these units.
- **Economic units:** Coal units that are less expensive than even the lowest long-term levelized market price are likely to remain economic under the current assumptions. Due to the large number of requirements faced by today's coal units, TVA should still carefully review the costs of maintaining and retrofitting these units; if costs are higher than estimated in this study, TVA should again review the economic merit of these units.

As we describe in detail below, this analysis demonstrates that the majority of TVA's coal capacity is not economic to retrofit under most compliance scenarios.

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[16] Assumptions from EPRI 2010. Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act; and EEI 2011 Potential Impacts of Environmental Regulation on the U.S. Generation Fleet.

[17] Energy efficiency long-term levelized cost from the TVA Global Energy Partners study (2011).

[18] I.e. an NGCC unit with high natural gas costs.

[19] The MATS rule requires compliance by 2015; one-year extensions are available under some circumstances.

C. Scenario 1: Consent Decree Only

The Consent Decree Only scenario represents TVA's barebones compliance obligations. It estimates only those costs which would be imposed directly by the CD. It is not a realistic scenario because TVA's many other public health and environmental obligations will impose additional costs on the coal fleet. We begin with it here, nonetheless, to demonstrate that, even with these relatively minimal controls, a large portion of TVA's coal capacity is not economic. As TVA considers how to comply with the CD, these conclusions alone argue strongly against many of the retrofits.

Reviewing the CD-required environmental capital expenditures for the remaining units at TVA, we estimate a total cost of approximately $3.9 billion (2010$) to retrofit all of the remaining coal units that are not required to retire by the CD, as shown in **Table 1**, below. Dollar costs are shown for wet FGDs, SCR, and baghouses where units are currently not equipped with these upgrades. We assumed that baghouses are required where they are not currently present in order to meet the CD's stringent particulate emissions limit.

Table 1. Capital costs required at TVA coal units to comply with the Consent Decree (2010$).

Plant / Unit	State	FGD Total Project Cost (Million $)	SCR Total Project Cost (Million $)	Baghouse Capital Cost (Million $)	Total Capital Expenditures (Million $)
Gallatin 1	TN	$178	$67	$44	**$290**
Gallatin 2	TN	$178	$67	$44	**$290**
Gallatin 3	TN	$190	$72	$48	**$310**
Gallatin 4	TN	$190	$72	$48	**$310**
Allen Steam Plant 1	TN	$192		$48	**$240**
Allen Steam Plant 2	TN	$192		$48	**$240**
Allen Steam Plant 3	TN	$192		$48	**$240**
Colbert 1	AL	$133	$47		**$180**
Colbert 2	AL	$133	$47		**$180**
Colbert 3	AL	$133	$47		**$180**
Colbert 4	AL	$133	$47		**$180**
Colbert 5	AL	$274		$80	**$354**
Shawnee 1	KY	$123	$44		**$167**
Shawnee 2	KY				
Shawnee 3	KY				
Shawnee 4	KY	$123	$44		**$167**
Shawnee 5	KY				
Shawnee 6	KY				
Shawnee 7	KY				
Shawnee 8	KY				
Shawnee 9	KY				
Widows Creek 7	AL				
Widows Creek 8	AL				
Paradise 1	KY				
Paradise 2	KY				
Paradise 3	KY				
Bull Run 1	TN			$113	**$113**
Cumberland 1	TN				
Cumberland 2	TN				
John Sevier 3	TN	$133	$47		**$180**
Kingston 1	TN			$32	**$32**
Kingston 2	TN			$32	**$32**
Kingston 3	TN			$32	**$32**
Kingston 4	TN			$32	**$32**
Kingston 5	TN			$35	**$35**
Kingston 6	TN			$35	**$35**
Kingston 7	TN			$35	**$35**
Kingston 8	TN			$35	**$35**
Kingston 9	TN			$35	**$35**

Total	$3,923

These capital costs translate into large forward-going costs. **Table 2** shows our estimated forward-going cost for the remaining TVA coal units against a levelized long-term market price. The designation of "Marginal" is divided into "High" and "Low" subparts of those units that are more expensive than the reference mid-level market price, versus those that are less expensive, respectively.

Table 2. Economic merit of TVA coal units in TVA with Consent Decree requirements only[20]

Plant / Unit	State	Forward-Going Cost for Existing Coal Units ($/MWh)	Levelized Long-Term Market Price ($/MWh)	Margin relative to Mid-Level Market Price ($/MWh)	Economic Condition.
Gallatin 1	TN	$59	$55	($5)	Marginal (High)
Gallatin 2	TN	$60	$55	($5)	Marginal (High)
Gallatin 3	TN	$57	$54	($3)	Marginal (High)
Gallatin 4	TN	$58	$54	($3)	Marginal (High)
Allen Steam Plant 1	TN	$51	$55	$4	Marginal (Low)
Allen Steam Plant 2	TN	$53	$57	$4	Marginal (Low)
Allen Steam Plant 3	TN	$54	$58	$4	Marginal (Low)
Colbert 1	AL	$66	$57	($10)	Marginal (High)
Colbert 2	AL	$71	$60	($11)	Non-Economic
Colbert 3	AL	$75	$62	($13)	Non-Economic
Colbert 4	AL	$68	$58	($10)	Marginal (High)
Colbert 5	AL	$67	$64	($2)	Marginal (High)
Shawnee 1	KY	$67	$58	($9)	Marginal (High)
Shawnee 2	KY	$34	$56	$23	Economic
Shawnee 3	KY	$34	$56	$22	Economic
Shawnee 4	KY	$67	$58	($9)	Marginal (High)
Shawnee 5	KY	$33	$55	$21	Economic
Shawnee 6	KY	$34	$56	$23	Economic
Shawnee 7	KY	$34	$57	$23	Economic
Shawnee 8	KY	$34	$58	$24	Economic
Shawnee 9	KY	$34	$57	$23	Economic
Widows Creek 7	AL	$40	$60	$20	Economic
Widows Creek 8	AL	$40	$59	$19	Economic
Paradise 1	KY	$34	$53	$19	Economic
Paradise 2	KY	$34	$53	$19	Economic
Paradise 3	KY	$35	$56	$21	Economic
Bull Run 1	TN	$53	$62	$8	Marginal (Low)
Cumberland 1	TN	$34	$53	$19	Economic
Cumberland 2	TN	$35	$54	$20	Economic
John Sevier 3	TN	$67	$55	($11)	Non-Economic
Kingston 1	TN	$64	$73	$9	Marginal (Low)
Kingston 2	TN	$70	$83	$13	Economic
Kingston 3	TN	$63	$71	$9	Marginal (Low)
Kingston 4	TN	$66	$77	$11	Marginal (Low)
Kingston 5	TN	$61	$71	$9	Marginal (Low)
Kingston 6	TN	$58	$65	$7	Marginal (Low)
Kingston 7	TN	$61	$70	$9	Marginal (Low)
Kingston 8	TN	$59	$67	$8	Marginal (Low)
Kingston 9	TN	$57	$64	$7	Marginal (Low)

Even with this extremely limited set of required costs, about half the TVA fleet (by capacity) is marginal to non-economic.

[20] Note that "Non-Economic", "Marginal" and "Economic" designations are compiled considering costs of CD retrofits only. Shawnee, Widows Creek, Cumberland, and Paradise require few if any retrofits under the CD, and thus appear to be economic from a forward-looking perspective. As we later show, they are largely not economic under more realistic future cost scenarios.

In particular, the Gallatin and Colbert units are universally between marginal and non-economic relative to the long-run market price even at CD-only requirements. The Allen units are also entirely marginal, as are Shawnee 1 and 4, the units addressed by the CD. The last of the John Sevier units is also clearly a candidate for retirement, particularly if the other John Sevier units are taken out of service. Overall, on the basis of the consent decree alone, even without considering other regulations that are currently being promulgated and/or implemented by EPA, and without a CO_2 cost, many of TVA's coal units are marginal. **Figures 1 & 2** below shows a graphical representation of the economic merit of each of TVA's remaining coal units.

The figures show the following information:

- **Unit Forward-Going Costs:** Each unit's estimated forward-going cost (as per Table 2, above) is plotted against the unit's average capacity factor over the last three years. Units are color-coded by plant, and the size of each bubble represents the capacity of the unit.
- **Long-run market prices:** The thick black curved line represents the levelized cost of the market over the long-run, where the all-in cost of a NGCC serves as a proxy cost.[21] Fixed costs and capital represent a higher fraction of the cost at lower capacity factors. Dotted lines represent a 33% deviation in natural gas prices impacting the long-run market cost.
- **Short term market prices:** The two thin dashed lines represent the 2011 market prices cleared in PJM West and MISO Cinergy that could be captured by an optimally-operated unit at any given capacity factor.[22] The PJM West price includes a capacity market adder. These prices are simple comparisons against market prices today.

As per Table 2, above, units that fall above the highest dotted line in **Figure 1** are non-economic. Units that fall between the dotted lines are marginal, and units that fall below the lowest dotted line would be economic in this limited cost future.

[21] The long run market price is represented here by the all-in cost of a new natural gas combined cycle unit, assumed to set the build margin. Higher costs at lower capacity factors represent a higher fraction of fixed and capital costs that must be recovered by a marginal actor.

[22] "Optimally-operated" would mean that a unit runs at the highest priced hours available only – i.e. a 30% capacity factor unit would run at all hours above the 70th percentile, and therefore capture the average of all prices above the 70th percentile. Similarly, a unit running near 100% capacity factor would capture the average of all prices in the year.

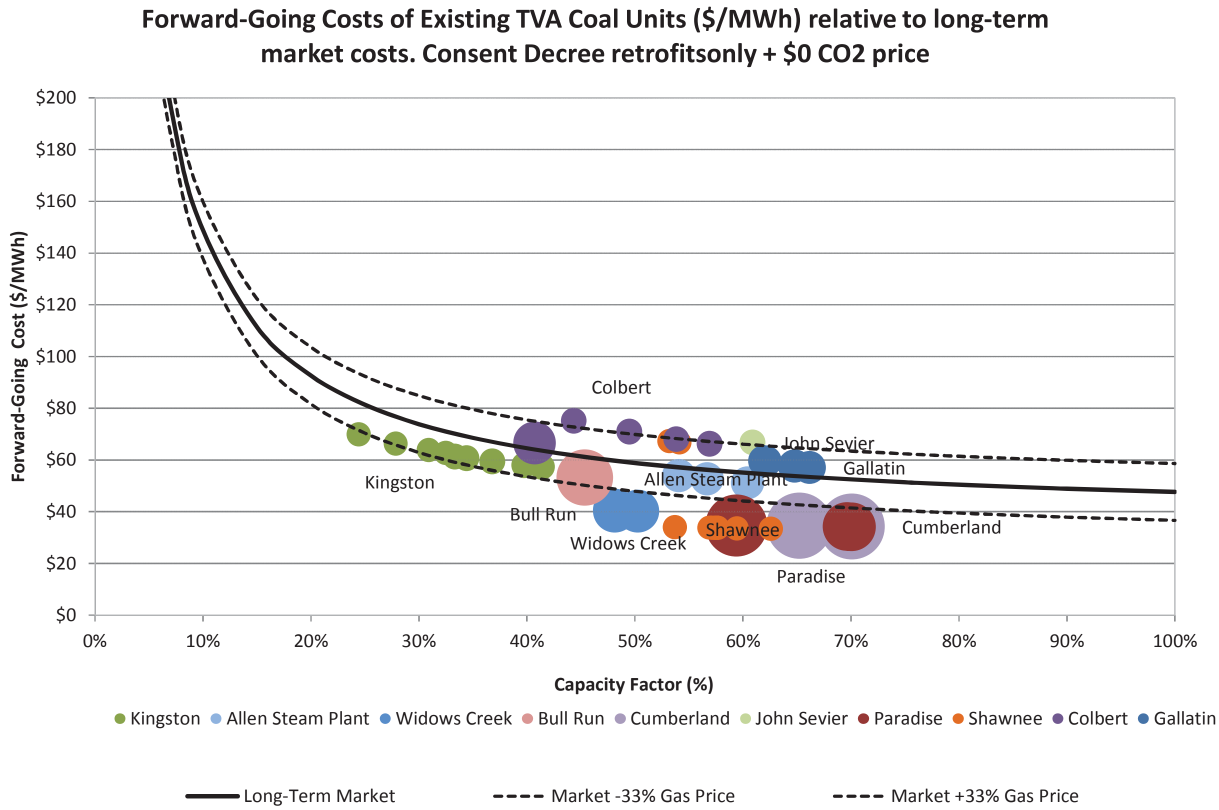

Figure 1. Forward-going costs of existing TVA coal units ($/MWh) relative to long-term market costs: Consent Decree Only scenario (selected FGD, SCR, and baghouse costs). Excludes units required for retirement by CD. See text for description.

Figure 1 shows Colbert 2 & 3 and John Sevier 3 as non-economic because they fall outside of the long-run market price bound. The other Colbert units, the Gallatin plant, and Shawnee 1 & 4 are all more expensive[23] than both current market prices and well above the expected long-run market price median.

Figure 2, below, shows that the forward going costs of many of these units are also well above the current market price curve in PJM and MISO (Cinergy).

[23] Shawnee 1 & 4 (orange dots) appear behind a Colbert unit (purple) in this graphic.

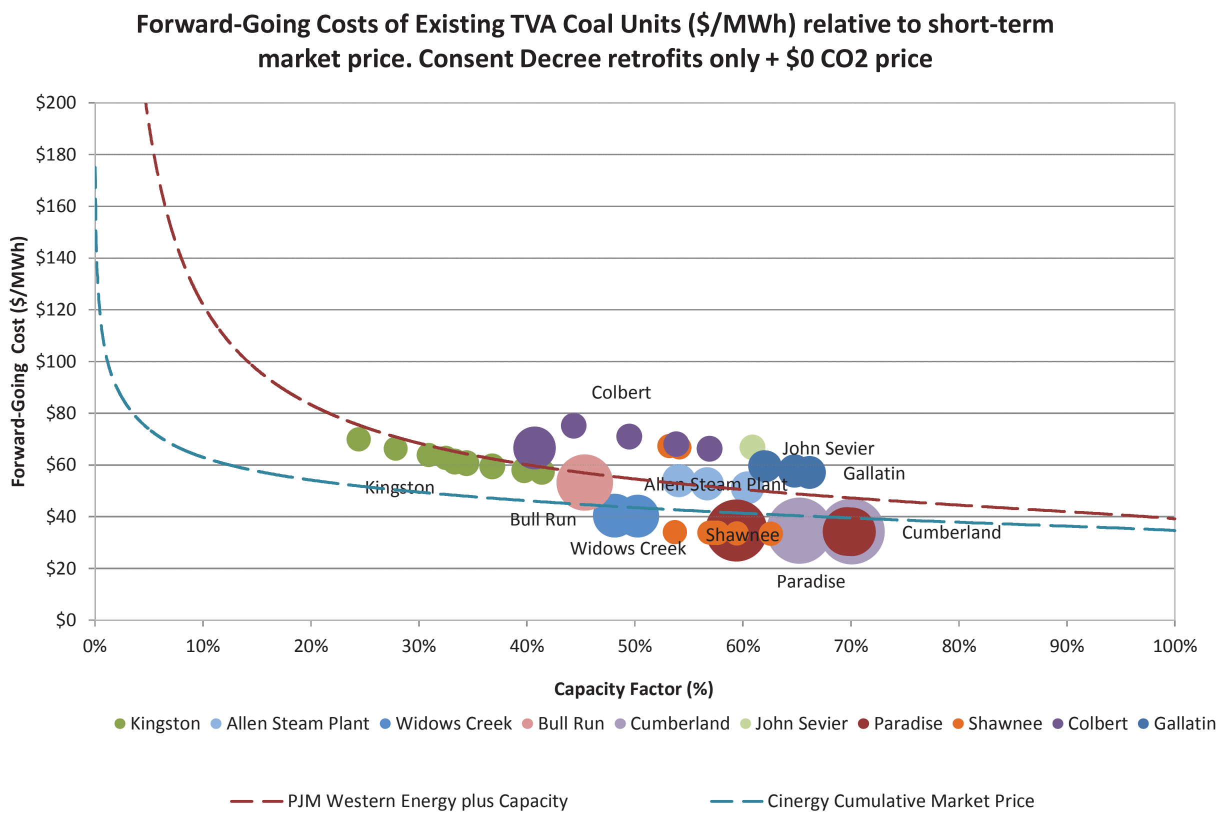

Figure 2. Forward-going costs of existing TVA coal units ($/MWh) relative to short-term market prices: Consent Decree Only scenario (selected FGD, SCR, and baghouse costs). Excludes units required for retirement by CD. See text for description.

This CD-only scenario appears to represent the outcome anticipated by TVA in the 2011 IRP. The IRP's "recommended" scenario "idles" 4,002 MW of dependable coal capacity by 2015.[24] It is unclear exactly which units are included in this cumulative count, but reviewing the requirements from the CD and modeling the economic merit of TVA's coal fleet with exclusive CD compliance suggests a specific slate of units. The CD requires the retirement of three units at John Sevier, all units at Johnsonville, and six units at Widows Creek. In addition, TVA retired Shawnee 10 and Watts Bar Fossil in 2011. Together these units, required for retirement by CD, are about 2,870 MW of dependable capacity – in other words, about 72% of the capacity contemplated for retirement in the IRP includes units that TVA <u>must</u> retire, by law. The remaining approximately 1,200 MW of capacity TVA planned to retire in 2011 could be met by the Colbert plant and the last John Sevier[25] unit.[26] It is possible that TVA has used another combination of units to make up the retirement portfolio, but this information has not been disclosed publicly.

[24] 2011 IRP EIS, Table 6-9.
[25] We assume John Sevier 3 for lack of information
[26] These six units actually add up to a net summer capacity of 1,360 MW according to EIA 2010. However, it is difficult to know if these are the same net dependable ratings used by TVA in their IRP analysis.

This outcome, however, is unrealistic. It does not account for all of the compliance costs before TVA – and fails to consider whether the retrofit costs for even relatively more economic plants are justified compared to other options, including efficiency.

The marginal units pose a marked risk to TVA and their distribution utilities - the utility will face new costs for CCR compliance, effluent limitation guidelines, and requirements to reduce water intake, as well as reduce mercury and meet more stringent NAAQS, CSAPR, and the MATS rule; any CO_2 price further demonstrates the questionable economic merit of the TVA coal fleet.

D. Scenario 2: Compliance with CSPAPR, MATS, ozone and SO_2 NAAQS, the water intake rule, CCR rule (subtitle C), and effluent limitation guidelines, and no CO_2 price.

To capture a more realistic picture, we next turn to a fuller suite of clean-up requirements. The large TVA coal-fired fleet faces a number of environmental compliance obligations.. In tandem with falling gas prices and the potential for CO_2 prices, these obligations demonstrate that TVA can better serve its ratepayers by seeking out lower-cost options than retrofitting its coal fleet, which is deep underwater.

Table 3, below, shows our estimate of overnight capital costs expected to be incurred at TVA's remaining coal-fired units to comply with CSAPR, MATS, SO_2, ozone, and PM NAAQS, the water intake rule, the CCR rule, and effluent limitation guidelines. Spaces with a dollar value indicate that a capital expenditure would be required to obtain a particular type of environmental control equipment or mitigation technique. Blank spaces indicate that a unit already has a state of the art control, according to EIA (2010) and EPA (2012). Costs are calculated from public source documentation, and do not represent unit specific engineering estimates.[27]

Table 3. Expected capital costs of compliance with all known major environmental rules and regulations for all remaining TVA coal units.

Plant / Unit	State	FGD (Million $)	SCR (Million $)	Baghouse (Million $)	ACI (Million $)	Wet Cooling Tower (Million $)	Coal Combustion Residuals (Million $)	Effluent Treatment (Million $)	Total Capital (Million $)
Gallatin 1	TN	$177	$67	$44	$3	$30	$58	$55	**$434**
Gallatin 2	TN	$177	$67	$44	$3	$30	$58	$55	**$434**
Gallatin 3	TN	$189	$72	$47	$3	$35	$59	$60	**$465**
Gallatin 4	TN	$189	$72	$47	$3	$34	$59	$60	**$464**
Allen Steam 1	TN	$190		$48	$3	$32	$63	$76	**$413**
Allen Steam 2	TN	$190		$48	$3	$30	$63	$76	**$411**
Allen Steam 3	TN	$191		$48	$3	$28	$63	$76	**$410**
Colbert 1	AL	$132	$47	$35	$3	$18	$53	$36	**$324**
Colbert 2	AL	$132	$47	$35	$3	$16	$53	$36	**$321**
Colbert 3	AL	$132	$47	$35	$3	$14	$53	$36	**$320**
Colbert 4	AL	$132	$47	$35	$3	$17	$53	$36	**$323**
Colbert 5	AL	$273		$79	$4	$36	$68	$100	**$560**
Shawnee 1	KY	$122	$44		$4	$15	$50	$28	**$263**
Shawnee 2	KY	$122	$44		$4	$16	$50	$28	**$264**
Shawnee 3	KY	$122	$44		$4	$17	$50	$28	**$264**

[27] Costs represent generic overnight capital costs for basic equipment sets under a set of basic assumptions. Costs do not represent physical construction difficulties, alternative configurations, or specific emissions limits. It is assumed that under the combination of CSAPR, MATS and NAAQS, most eastern coal units will require FGD, SCR, baghouses, and ACI. Costs also assume that all once-through cooled units will be retrofit with cooling towers.

Shawnee 4	KY	$122	$44		$4	$15	$50	$28	**$263**
Shawnee 5	KY	$122	$44		$4	$17	$50	$28	**$265**
Shawnee 6	KY	$122	$44		$4	$16	$50	$28	**$264**
Shawnee 7	KY	$122	$44		$4	$16	$50	$28	**$264**
Shawnee 8	KY	$122	$44		$4	$15	$50	$28	**$263**
Shawnee 9	KY	$122	$44		$4	$16	$50	$28	**$264**
Widows Creek 7	AL			$86	$4	$44	$62	$92	**$288**
Widows Creek 8	AL			$94	$4	$44	$61	$87	**$291**
Paradise 1	KY			$97	$4		$62	$88	**$251**
Paradise 2	KY			$97	$4		$62	$88	**$251**
Paradise 3	KY			$135	$4		$72	$103	**$314**
Bull Run 1	TN			$112	$4	$69	$101	$246	**$532**
Cumberland 1	TN			$161	$4	$145	$75	$176	**$563**
Cumberland 2	TN			$162	$4	$135	$75	$176	**$553**
John Sevier 3	TN	$131	$47	$35	$3	$19	$58	$62	**$355**
Kingston 1	TN			$31	$3	$9	$50	$29	**$123**
Kingston 2	TN			$31	$3	$7	$50	$29	**$121**
Kingston 3	TN			$31	$3	$9	$50	$29	**$123**
Kingston 4	TN			$31	$3	$8	$50	$29	**$122**
Kingston 5	TN			$35	$3	$11	$51	$33	**$133**
Kingston 6	TN			$35	$3	$13	$51	$33	**$135**
Kingston 7	TN			$35	$3	$11	$51	$33	**$134**
Kingston 8	TN			$35	$3	$12	$51	$33	**$134**
Kingston 9	TN			$35	$3	$13	$51	$33	**$136**
								Total	**$11,810**

In total, TVA could be looking at $11.8 billion to retrofit all of its non-retiring coal units.

These additional capital and O&M expenses render far more of the TVA fleet noneconomic relative to a long-run market replacement option. Using the same mechanism as the first scenario, we find that looking at likely required capital costs, nearly half of the TVA fleet can reasonably be expected to be clearly non-economic - i.e. these units would not recover their own costs on an open market (see **Table 4**).

Table 4. Economic merit of TVA coal units in TVA with full existing, proposed, and expected EPA rule requirements. Exclusive of carbon price.

Plant / Unit	State	Forward-Going Cost for Existing Coal Units ($/MWh)	Levelized Long-Term Market Cost ($/MWh)	Margin relative to Mid Price	Economic Condition.
Gallatin 1	TN	**$73**	$55	($18)	Non-Economic
Gallatin 2	TN	**$73**	$55	($18)	Non-Economic
Gallatin 3	TN	**$69**	$54	($15)	Non-Economic
Gallatin 4	TN	**$70**	$54	($16)	Non-Economic
Allen Steam Plant 1	TN	**$66**	$55	($10)	Marginal (High)
Allen Steam Plant 2	TN	**$68**	$57	($11)	Non-Economic
Allen Steam Plant 3	TN	**$70**	$58	($12)	Non-Economic
Colbert 1	AL	**$87**	$57	($31)	Non-Economic
Colbert 2	AL	**$95**	$60	($35)	Non-Economic
Colbert 3	AL	**$101**	$62	($39)	Non-Economic
Colbert 4	AL	**$90**	$58	($33)	Non-Economic
Colbert 5	AL	**$82**	$64	($18)	Non-Economic
Shawnee 1	KY	**$88**	$58	($30)	Non-Economic
Shawnee 2	KY	**$85**	$56	($28)	Non-Economic
Shawnee 3	KY	**$83**	$56	($28)	Non-Economic
Shawnee 4	KY	**$89**	$58	($31)	Non-Economic
Shawnee 5	KY	**$81**	$55	($26)	Non-Economic
Shawnee 6	KY	**$85**	$56	($28)	Non-Economic
Shawnee 7	KY	**$85**	$57	($29)	Non-Economic
Shawnee 8	KY	**$88**	$58	($30)	Non-Economic
Shawnee 9	KY	**$85**	$57	($29)	Non-Economic
Widows Creek 7	AL	**$59**	$60	$2	Marginal (Low)
Widows Creek 8	AL	**$58**	$59	$1	Marginal (Low)
Paradise 1	KY	**$43**	$53	$10	Marginal (Low)

Paradise 2	KY	**$43**	$53	$10	Marginal (Low)
Paradise 3	KY	**$42**	$56	$13	Economic
Bull Run 1	TN	**$69**	$62	($8)	Marginal (High)
Cumberland 1	TN	**$45**	$53	$8	Marginal (Low)
Cumberland 2	TN	**$46**	$54	$8	Marginal (Low)
John Sevier 3	TN	**$91**	$55	($36)	Non-Economic
Kingston 1	TN	**$92**	$73	($19)	Non-Economic
Kingston 2	TN	**$105**	$83	($22)	Non-Economic
Kingston 3	TN	**$90**	$71	($19)	Non-Economic
Kingston 4	TN	**$98**	$77	($20)	Non-Economic
Kingston 5	TN	**$87**	$71	($16)	Non-Economic
Kingston 6	TN	**$80**	$65	($15)	Non-Economic
Kingston 7	TN	**$85**	$70	($16)	Non-Economic
Kingston 8	TN	**$83**	$67	($15)	Non-Economic
Kingston 9	TN	**$78**	$64	($14)	Non-Economic

Thirty (30) TVA coal units, representing 8,020 MW (or 56% of TVAs non-retiring coal capacity), are likely to be more expensive than the expected long-term market cost of generation[28] when reasonably required capital costs are taken into account. Most of these units are simply non-economic (6,740 MW). As the most recent and most controlled unit, only Paradise 3 remains in the category of "economic."

The graphic below shows the distribution of units in the same scatter plot, now with the added capital and O&M expenses for the equipment in Table 4, above.

[28] A designation of "non-economic" or "Marginal (high)"

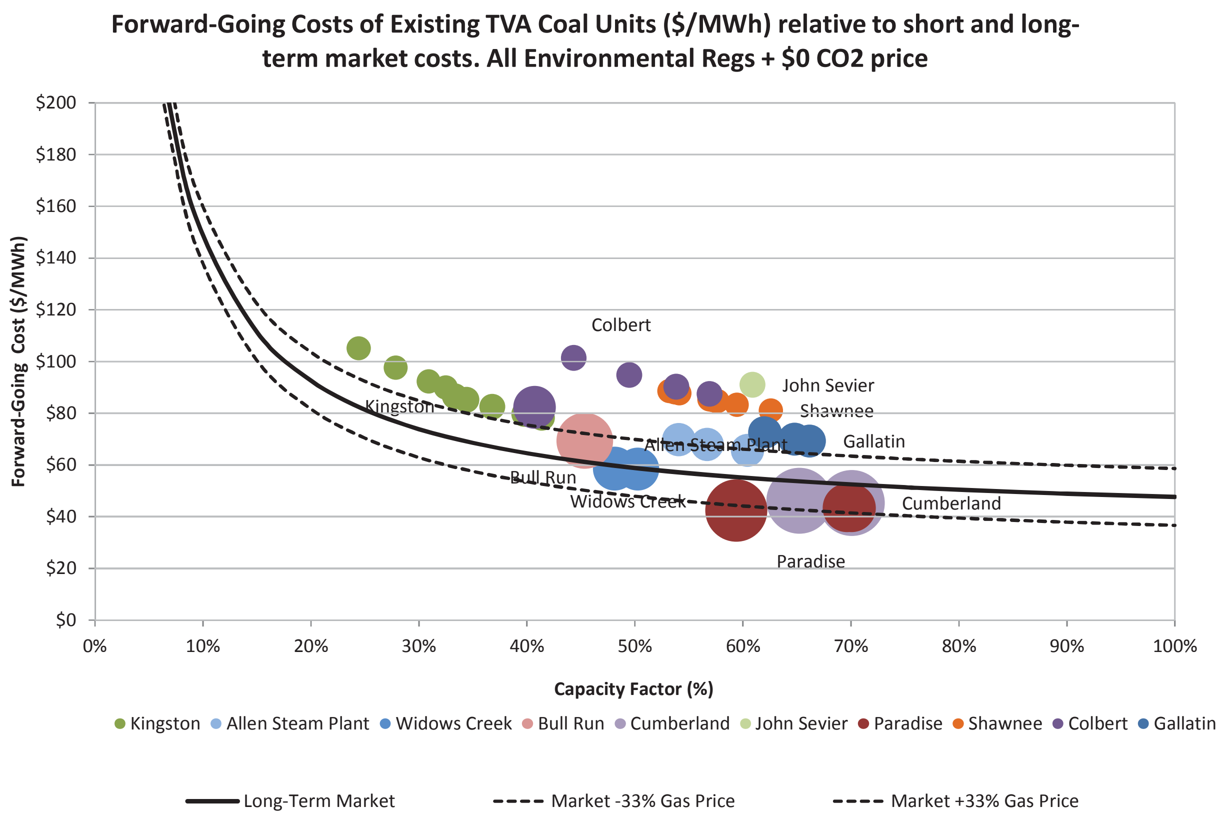

Figure 3. Forward-going costs of existing TVA coal units ($/MWh) relative to new NGCC: All known and expected environmental compliance costs (MATS, CSAPR, NAAQS, water intake, effluent, CCR) exclusive of carbon price.

Under this more realistic scenario, in short, retrofitting TVA's coal fleets is a bad deal for ratepayers. But even this scenario is not the end of the story: These costs assume that there is no CO_2 price, an assumption that is not consistent with most utilities and inconsistent with most of TVA's planning scenarios. Adding in a CO_2 price makes even clearer that the majority of the fleet is not economic.

E. Scenario 3: Compliance with CSPAPR, MATS, ozone and SO2 NAAQS, the water intake rule, CCR rule (subtitle C), and effluent limitation guidelines, and a $21/tCO_2$ price.

Finally, adding in a moderate CO_2 price of $21/tCO_2$ results in nearly every unit in the TVA fleet looking non-economic relative to a long-run market proxy price. With the exception of the units at Paradise and Cumberland, and at Widows Creek 7 & 8 which are marginal at this CO_2 price, this analysis shows that 64% of TVAs coal capacity (8,570 MW) is non-economic under a reasonable set of forward-looking assumptions.

The \$21/tCO_2 price contemplated here represents the real levelized cost of a price forecast used by Synapse Energy Economics.[29] This forecast starts in 2018 and rises linearly to \$80 by 2040. Overall, the trajectory is later, lower, and slower than most of TVA's CO_2 price forecasts as used in the 2011 IRP. With the exception of Scenario 3 in the TVA 2011 IRP with a zero CO_2 price, the levelized price of the TVA's forecasts range from \$29 to \$53/tCO_2, significantly higher than the price contemplated here.

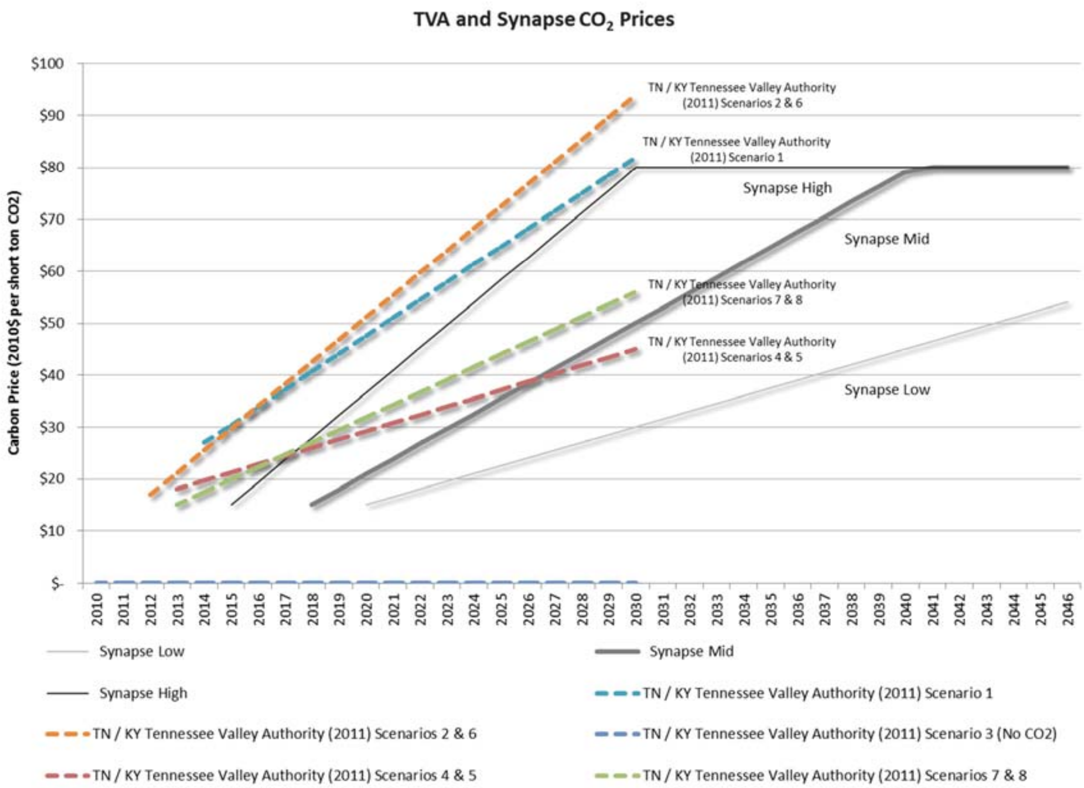

Figure 4. 2011 TVA and Synapse CO_2 price forecasts. TVA forecasts from 2011 IRP.

Figure 5 shows the merit of TVA's fleet under the likely set of EPA regulations and the \$21 CO_2 price. This analysis shows that <u>any</u> forward-going investments in the TVA coal fleet should absolutely be deferred until TVA undertakes a complete analysis on the economics of its existing fleet and explores viable alternatives for the existing fleet, including energy efficiency, renewable energy, market purchases, and replacement generation options.

[29] \$27/tCO_2 is the levelized equivalent of a \$15/tCO_2 price starting in 2018 and rising to \$80/tCO_2 by 2040. Levelization from 2012 to 2034 with a 5.4% real discount rate.

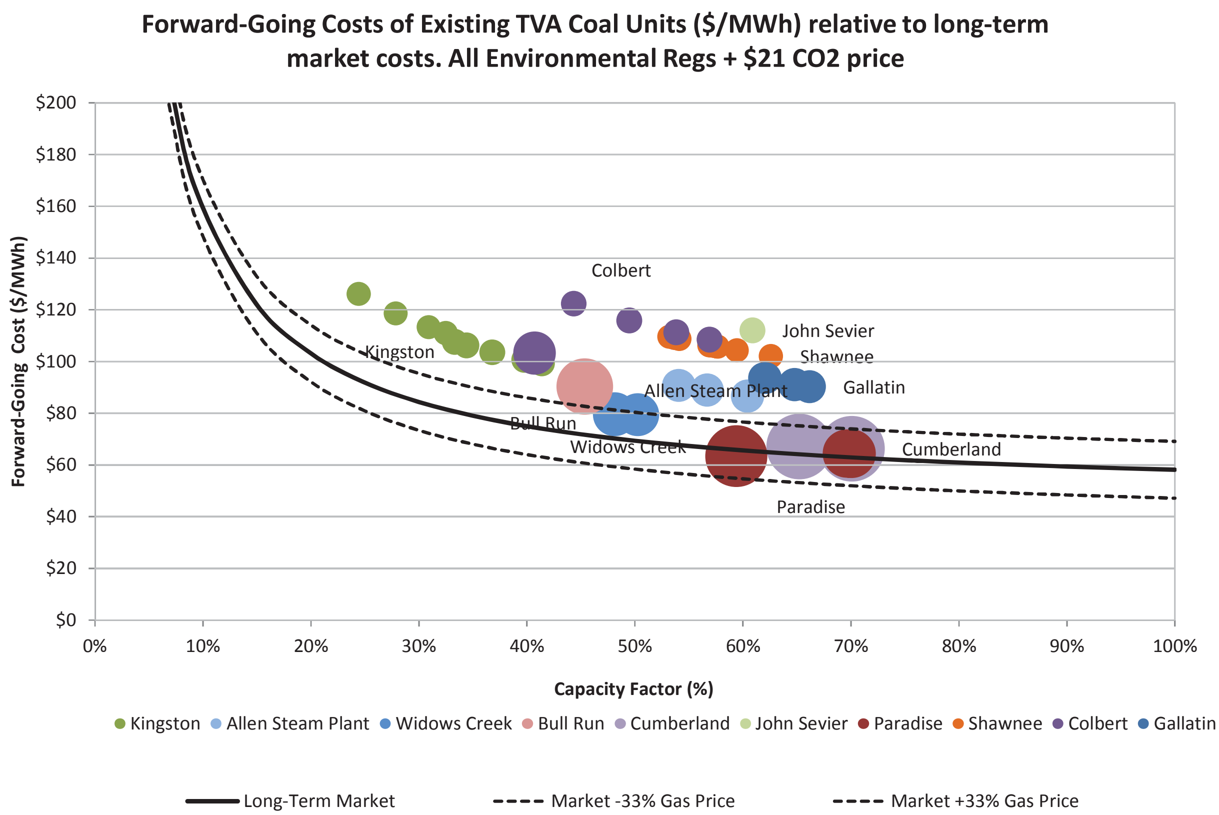

Figure 5. Forward-going costs of existing TVA coal units ($/MWh) relative to new NGCC: All known and expected environmental compliance costs (MATS, CSAPR, NAAQS, water intake, effluent, CCR) plus $21/tCO_2$ price.

4. A Window of Opportunity at TVA for Energy Efficiency and Clean Power

The increasingly burdensome running TVA's aging coal fleet places on ratepayers, and on TVA itself, presents the utility with a unique opportunity to revisit its fleet and carefully consider which units should carry investments and which are more appropriately retired. Indeed, as we have demonstrated above, if TVA is to upgrade its fleet to meet modern public health and environmental standards, we estimate that it may be looking at $11.8 billion of near-term capital investments to keep its current coal units in operation. If TVA moves to exclusively retrofit the fleet, rather than retire non-economic units, it will be facing a (present value) commitment of about $50-$70 billion of capital, operating, and fuel costs on all remaining coal units from 2016-2032. TVA has far better options.

Energy efficiency investments offer a clear path forward that would protect ratepayers while avoiding unnecessary and uneconomic retrofits to many of TVA's old coal units. According to a recent study commissioned by TVA from Global Energy Partnership (GEP),[30] energy efficiency investments would

[30] Global Energy Partners 2011. Tennessee Valley Authority Potential Study, December 2011.

allow the utility to achieve and maintain 1,590 MW in savings by 2015,[31] the compliance deadline of EPAs MATS rule. This level of savings would be sufficient to completely replace, for example, the capacity now provided by the 1,200 MW Gallatin plant, saving an estimated $1.8 billion in retrofit capital costs over the next decade, and ultimately saving consumers at least $2.7 billion between 2012 and 2032.

Alternatively, the utility could embark on a more aggressive EE program, reaching toward the 2% of annual savings already realized by leading utilities and now targeted by several states in the form of energy efficiency resource standards.[32] At this level of savings, TVA could reduce demand by 2,750 MW in 2016, enough to replace at least the capacity needs now met by Gallatin, Colbert, and John Sevier 3. This trajectory would reduce capital expenditures by about $4 billion over the next decade, and ultimately save ratepayers about $6.6 billion between 2016 and 2032.

These results make clear that energy efficiency is, by far, the better economic choice for TVA as it contemplates whether to invest in efficiency or in additional coal retrofits. In some cases, efficiency can replace coal units before they must be retrofitted in response to regulations. Further downstream, efficiency can offset the need for future replacement capacity, help avoid costly new generation, support reliability, reduce risk, and lower the cost of decarbonization.

A. The Global Energy Partners (GEP) Energy Efficiency Study

Our analysis is based upon a 2011 study by Global Energy Partners ("GEP EE Study") which TVA commissioned.[33] The study reviewed a large number of energy efficiency programs and estimated the level of energy efficiency that could be obtained by TVA under a "low achievable" and "high achievable" future. The "low achievable" scenario envisioned approximately 0.5% to 0.7% incremental efficiency savings per year for a total reduction of about 11% by 2030, while the "high achievable" scenario doubled that rate for a maximum incremental savings of 1.2% per year, reducing load 20% by 2030. TVA has indicated that it intends to use the GEP study in future planning.[34] As we explain below, our economic analysis of the merits of energy efficiency, compared to coal retrofits, indicates the urgent need to incorporate these results in TVA decisionmaking.

The GEP EE study uses lifetime cost of saved energy (CSE) to calculate the amount TVA must invest to achieve these goals.[35] It concludes that the lifetime CSE costs of the "low achievable" EE scenario are approximately $0.04/kWh ($40/MWh), while the "high achievable" scenario is about $0.07/kWh

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[31] Using GEP cost assumptions. See "Achievable High" in Table 6-1 in "Volume 2: Energy Efficiency Potential Study" of GEP Study

[32] For example: ME (30% reduction by 2020), MA (1,103 GWh in 2012; 2.4% in 2012), AZ (22% cumulative savings by 2020), RI (2.5% reduction in 2014), and VT (320,000 MWh savings for 2012; 1.95% achieved in 2010). See http://www.dsireusa.org/documents/summarymaps/EERS_map.pdf and http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2010_Annual_Report.pdfhttp://www.dsireusa.org/documents/summarymaps/EERS_map.pdf

[33] Global Energy Partners. December 21, 2011. Tennessee Valley Authority Potential Study. Report Number 1360.

[34] See TVA Press Release: "TVA Study Shows Regional Energy Efficiency Potential" (Feb. 7, 2012), available at http://www.tva.com/news/releases/janmar12/energy_efficiency.html.

[35] EE costs can be thought of as either "first year" costs, which are the total capital costs incurred at the implementation of a program (i.e. the cost to buy a wedge of EE), or levelized "lifetime" costs, which are those same costs, amortized over the expected lifetime of a particular EE program at a certain discount rate. The cost of saved energy (CSE), the equivalent to the cost of generation in $/kWh, can therefore be expressed either in first-year CSE or levelized lifetime CSE, First-year CSE values are useful for estimating annual program expenditures or savings based on a given budget or spending level, but lifetime CSE values are the appropriate measure to compare the cost of traditional generation against EE costs.

($70/MWh).[36] The first set of costs ($0.04/kWh) are clearly lower than just about any new generation resource, and are lower than the all-in cost of most existing generation resources as well, including the costs of all of TVA's coal units. The second set of costs ($0.07/kWh) are competitive with the forward-going cost of most of TVA's coal units (see **Table 4** above), and less expensive by a wide margin than the forward-going cost of the least economic generators.

B. Using Energy Efficiency to Avoid Major New Retrofit Costs for Old Coal Plants

What coal generation retrofit and operating costs could TVA avoid through efficiency, and at what cost? The GEP study provides an avenue to explore this question, examining energy and capacity savings, as well as expected first-year costs every five years for both EE scenarios. As we explain, that study demonstrates that efficiency allows TVA to offset significant retrofit costs on a short time-table, even though GEP used very conservative assumptions. With more realistic assumptions as to the cost and availability of EE, even greater cost savings are possible.

To begin our analysis, we used a simplified mechanism to estimate how much efficiency would be required to replace retiring coal capacity, and then maintain that level of efficiency through the end of the GEP study period (2032). We can compare the total cost to achieve and maintain that level of EE with the all-in cost of retrofitting and operating the equivalent amount of coal capacity, and to determine which path has lower costs on a present-value basis. Finally, we observe that more realistic cost assumptions indicate that even greater savings are possible with EE than the GEP study predicts.

i. *Avoiding Wasteful Investments at Individual TVA Coal Plants with Efficiency*

The GEP study estimates that the "achievable high" EE scenario could reduce demand by nearly 10,000 MW by 2030 or nearly 20% of the projected load (see **Figure 6**, below). While this level of savings is well above TVA's historic performance, it is not unprecedented for leading utilities.

[36] Utility cost estimate.

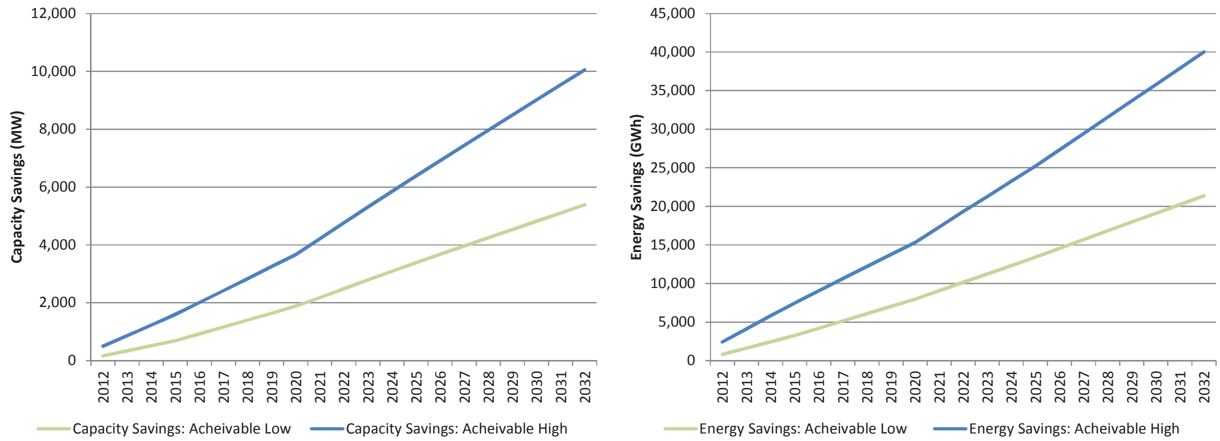

Figure 6. Capacity (MW) and energy (GWh) savings, respectively estimated in GEP study (Table 6-1)

However, coal retirements would need to happen by 2015-2016 to avoid many compliance costs associated with pending regulations, not 2030, meaning that EE savings in the next four years are of particular importance to avoiding retrofits.[37] To focus on this compliance window, we therefore looked at EE ramp-up costs in the 2015-16 period.

The GEP study estimates potential capacity savings of 1,590 MW by 2015 in the "achievable high" scenario (~2,000 MW by 2016). This is enough capacity to easily accommodate the retirement any one of TVA's highly non-economic coal plants. In this case, we explore retirement of either Gallatin (1255 MW), Colbert (1350 MW), or Allen (990 MW), or the combination of Shawnee 1 & 4 and John Sevier 3 & 4 (750 MW). In the case of Allen and the Shawnee/John Sevier combination, the "achievable high" scenario offsets these plants by 2014 (1,226 MW of savings).

The total first-year cost to achieve 1,590 MW, or 7,494 GWh, of energy savings by 2015 is approximately $1.9 billion (2009$) from 2012-2015, according to the GEP study.[38] These costs compare to similar immediate capital costs for retrofits at just the Allen and Gallatin plants, for instance, and produce significantly greater long-term benefits than those retrofits would do. We calculated the long-term costs of maintaining these EE savings. Energy efficiency programs are typically considered by planners and program administrators to require continued investment to maintain savings – conservatively, planners thus sometimes assume that EE program effectiveness will decay in around twelve years without program support, depending on the longevity of the EE equipment and replacement rate.[39] Taking this conservative assumption, we therefore assume that to maintain this level of savings, TVA would have to

[37] Our analysis is highly conservative, only accepting retirements if the total requirement can be met with energy efficiency. In reality, however, later savings are also relevant: If TVA could, for instance, *almost* replace a plant's capacity with EE within a few years after a compliance deadline, it could make sense to idle the plant and purchase power on the market for the gap period while EE comes up to speed. Such an alternative is not modeled here.

[38] Values derived from Table 7-2 of the GEP study.

[39] The effects of energy efficiency measures typically vary widely from measure to measure, ranging from a few years for lighting to as many as 20 for HVAC or 30 years for building envelope measures such as insulation, a program as a whole typically has about 12 year savings effect on "average".

steadily re-invest in about 50% of the achieved EE to ensure that savings do not retire with equipment.[40] For the purposes of this analysis, we assume a flat decay rate of 8.3% per year based on a 12-year lifetime, and that 50% of pre-existing savings level reoccur without additional program spending. In other words, on this analysis, TVA must invest in 4.2% of the equivalent new EE program each year to maintain those savings, [41] or approximately 312 GWh of new savings per year (4.2% of 7,494 GWh).

To further err on the conservative side, we use an implicit GEP assumption that EE programs become more expensive at deeper levels of penetration as low-cost opportunities disappear. Importantly, this trend is <u>not</u> supported by evidence from other utilities and states. In general, EE programs become markedly less expensive at higher levels of penetration, as discussed later in this report.

Nonetheless, to enact the conservative assumption, we tally the running cumulative sum of both paid-for and naturally re-occurring savings each year (i.e. 8.4% of 7,494 GWh) and determine a first-year price for that EE based on GEP's assumed EE supply curve. That first year price rises from $0.31/kWh in 2016 (the first year of "maintenance" savings) to $0.68/kWh by 2032 (the last year of the analysis. Therefore, the cost of maintaining 1,590 MW or 7,494 GWh of efficiency from 2016 through 2032 rises from $97 million[42] to $213 million over that span.

Following the cost of saved energy supply curves based on GEP's assumption, our conservative (i.e. high cost) estimate of the cost of achieving 1,590 MW of efficiency and maintaining that level of savings through 2032 is approximately $3.3 billion on a present value basis. In contrast, the all-in cost of retrofitting and operating the Gallatin plant from 2015 through 2032, for example, is $5.7 billion without a CO2 price and $7.4 billion with a $21/t$CO_2$ price.

In sum, even if we make conservative assumptions about the cost and longevity of EE, it is a substantially better investment than retrofitting Gallatin. With no cost on carbon, EE saves $2.7 billion (present value) relative to the cost of retrofitting Gallatin, yielding a benefit/cost ratio of 1.89. With a reasonable cost on carbon, EE saves $4.4 billion relative to the retrofit cost a benefit/cost ratio of 2.44.

This analysis looks much the same for many other coal units in the TVA system. Over and over again, investing in EE is a better economic choice – by billions of dollars – than investing in retrofitted coal units. The following table shows the all-in present value cost of providing efficiency from 2012 through 2032 to replace some of the least economic coal units versus the all-in present value cost of retrofitting and maintaining those coal units from 2015-2032, in billions of 2009$. In all cases, there is a significant benefit in replacing these coal units with energy efficiency.

[40] Even after TVA's efficiency programs reach the level of savings that can replace its coal fleet retirements, we conservatively assume that it has to keep investing in energy efficiency, but at much lower level (1/12th of the upfront investment).

[41] 4.2% = 1/12yrs * (1-50% naturally re-occurring savings). Naturally re- occurring savings include customers who re-invest in efficient hardware without incentives because of market transformation and realized savings. It may also include savings associated with future energy efficiency policies at state and federal levels (e.g., building codes and appliance standards), the impact of which are not currently reflected in the load forecasts. Naturally re-occurring savings do not impact the initial investment required to reach the full level of savings.

[42] $0.31/kWh * 312 MW = $97 million

Table 5. All-in present value cost of "high achievable" energy efficiency path to replace various coal units versus all-in present value to retrofit and maintain same units, in billions of 2009$. Energy efficiency includes costs from 2012 (ramp-up period), while coal only includes cost from 2015 through end of analysis period (2032). Values may not add due to rounding.

Plant	Cost of "High Achievable" EE (2012-2032) to replace unit	All-in Cost of maintaining coal unit, no CO_2 (2015-2032)	*Net benefit of EE relative to retrofit*	All-in Cost of maintaining coal unit, \$21/tCO_2 (2015-2032)	*Net benefit of EE relative to retrofit*
Gallatin	\$3.1	\$5.7	\$2.7	\$7.4	\$4.4
Colbert	\$3.1	\$5.7	\$2.7	\$7.0	\$4.0
Allen	\$2.4	\$3.9	\$1.5	\$5.1	\$2.7
SN 1&4 / JS 3&4	\$1.6	\$3.7	\$2.1	\$4.5	\$2.9

These benefits also appear in customer bills. Retrofits are clearly expensive, and customer bills can be expected to increase markedly to cover the costs of these upgrades. For the Gallatin unit, for example, we might expect average residential bills to increase by about \$2.60 per month when the costs of the retrofits are brought into rate base. Efficiency also costs money, but not nearly as much as maintaining an aging coal unit with expensive retrofits. We have calculated these likely bill impacts. **Figure 7** below shows the average cost difference in an average month that would be caused by either retrofits or efficiency (that is, in 2016, for instance, monthly bills would be about \$2.60 higher than they otherwise would be with a retrofit; with efficiency, they would be only \$0.40 higher than the baseline) Over the first four years of an efficiency ramp-up, we would expect customer bills to increase gradually to an additional monthly fee of about \$2.30 in 2015 (relative to today); however, as soon as the Gallatin unit is retired, efficiency immediately starts producing savings. Customer bills in a typical month after 2015 would be about \$2.20 per month lower than they would be in the retrofit case.

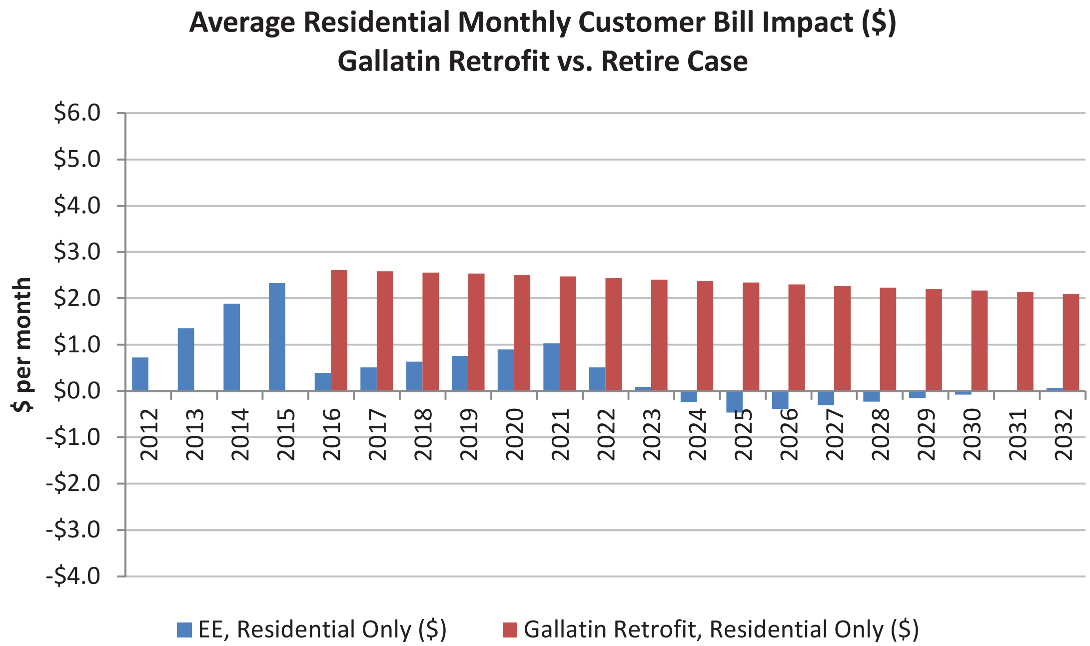

Figure 7. Average residential customer bill impact to fully retrofit the Gallatin plant, including incremental O&M costs to operate FGD, SCR, and baghouse (in red); versus bill impact to achieve 1.2% savings per year, and maintain 1,590 MW of energy reduction by 2015 (in blue). Coal costs are exclusive of CO_2 price.

Bill savings may well be even greater. In Figure 7 shown here, the cost of the retrofit (in red) includes the capital cost of the retrofit (amortized over 20 years) and incremental O&M costs to operate the coal plant from 2016 through 2032. The energy efficiency (in blue) represents the cost to achieve 1.2% savings per year from 2012 through 2015, and then maintain 1,590 MW of relative reduction through the end of the analysis period minus the savings from retiring the plant (i.e. base fuel and O&M costs).[43] The avoided costs of the coal unit do not include CO2 costs. If we expect a mid-level cost on CO2, the relative savings from EE are even higher – or a difference of about $3.50 savings per month relative to the retrofit scenario, as shown in Figure 8, below.

[43] All EE costs are capitalized over 10 years. EE costs = amortized first year costs to achieve and then maintain savings minus base coal fuel and O&M expenses. Coal retrofit costs = amortized capital costs of retrofit + incremental O&M costs of retrofit only.

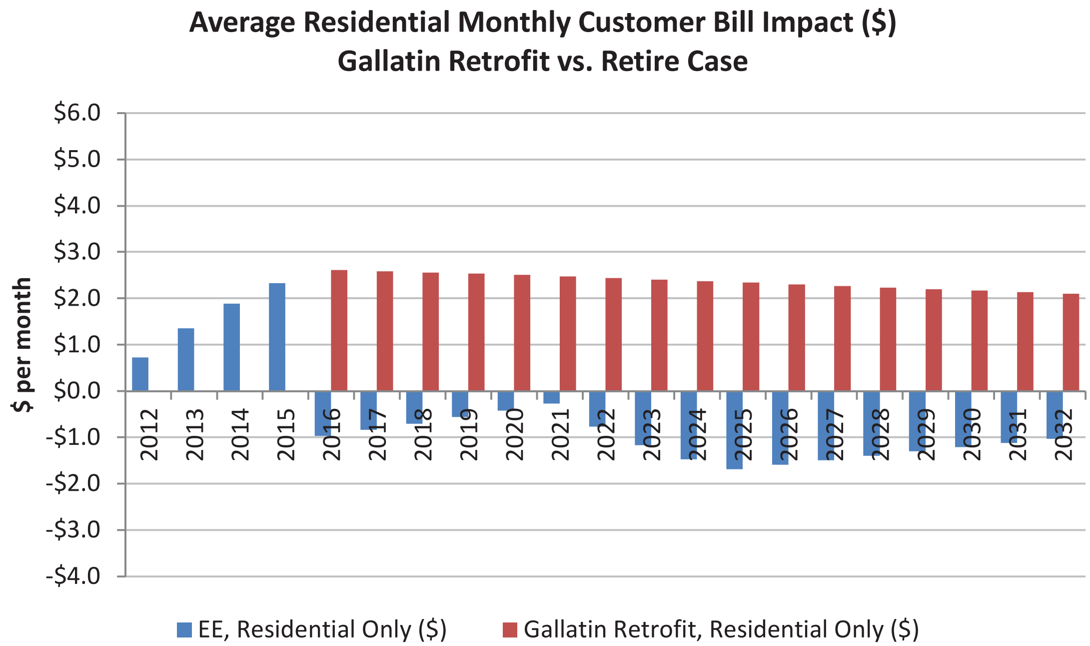

Figure 8. Average residential customer bill impact to fully retrofit the Gallatin plant, including incremental O&M costs to operate FGD, SCR, and baghouse (in red); versus bill impact to achieve 1.2% savings per year, and maintain 1,590 MW of energy reduction by 2015 (in blue). Coal costs include levelized $21/tCO_2$ price.

ii. *Avoiding Wasteful Investments at Multiple TVA Coal Plants with Efficiency Investments Commensurate with Leading Utilities*

Assuming that TVA is only able to achieve, at its very best, 1.2% incremental savings per year, the utility could nonetheless achieve 2,000 MW in savings by 2016. However, this incremental savings rate is well below the rate of some of the leading utilities and energy efficiency program administrators which have achieved at least 2% per year. For example, Efficiency Vermont, Vermont's statewide energy efficiency program administrator, had nearly 2.5% annual savings in 2008, and saved about 2% annually in 2010 and 2011 right after the recession.[44] In addition, there are now many states across the nation that target 2% annual savings under state energy efficiency resource standards.[45] The American Council for an Energy-Efficient Economy (ACEEE) put together the following chart summarizing the cumulative impact of such path-breaking energy efficiency resource standards in its report issued in 2011.

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[44] Efficiency Vermont 2012. 2011 Savings Claim, Figure 2, April 2012, available at http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2011_Savings_Claim_Summary_EfficiencyVermont.pdf

[45] MA EEAC 2009. Assessment of All Available Cost-Effective Electric and Gas Savings: Energy Efficiency and CHP, page 16; ACEEE 2011. Energy Efficiency Resource Standards: A Progress Report on State Experience, June 2011.

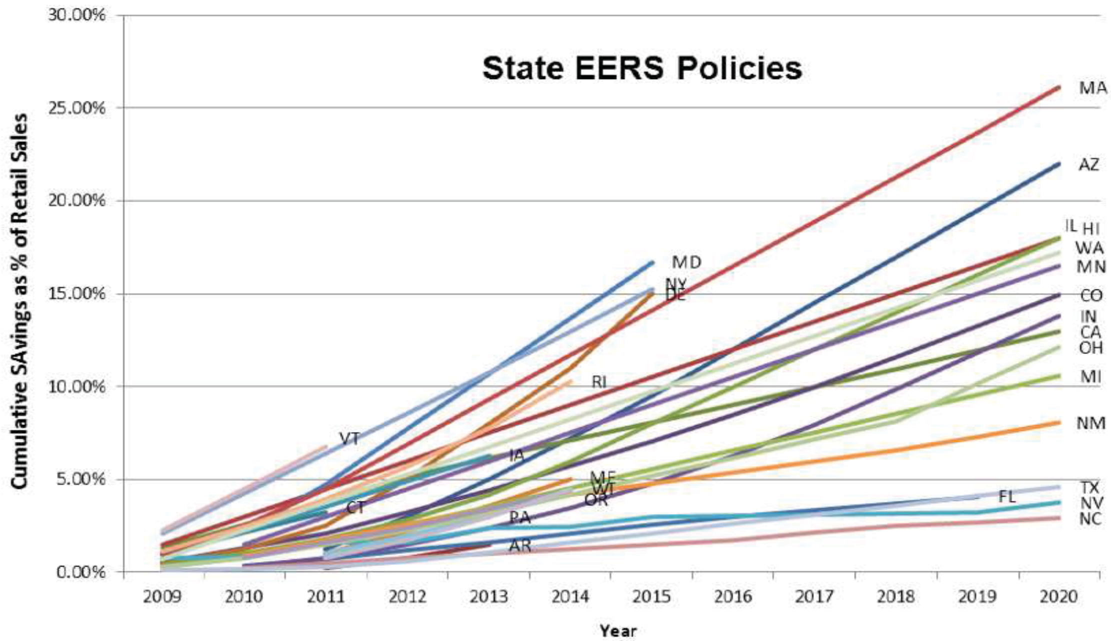

Figure 9. State energy efficiency resource standards (EERS).[46]

Consistent with these programs, and its goal to become a leader on energy efficiency, if TVA were to commit to a more rapid deployment of efficiency programs, we estimate that the utility could achieve enough savings by 2016 to replace the capacity of <u>both</u> the Gallatin and Colbert plants as well as one unit of John Sevier (#3) with efficiency alone.[47] Ramping from 1.1% in 2013 to 2.0% in 2015, the utility could reduce capacity requirements by 2,750 MW in 2016 – or enough to cover capacity requirements for all of these non-economic units or any other combination units with that capacity. Using the same ratio of energy to capacity as estimated in the GEP study, we would estimate a savings of approximately 12,400 GWh in 2016 (see **Figure 10**, below).

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46 ACEEE, 2011. Energy Efficiency Resource Standards: A Progress Report on State Experience.

47 We use the John Sevier unit as an example. Other individual units with similar economics and capacity, such as one of the Shawnee units, could be replaced with similar results.

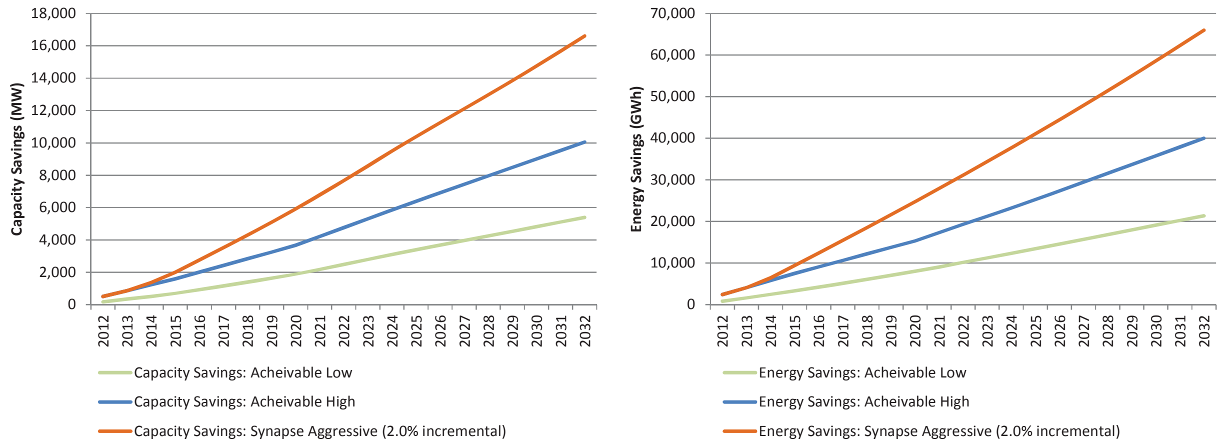

Figure 10. Capacity (MW) and energy (GWh) savings estimated in GEP TVA study and at 2% incremental per year ("Synapse Aggressive")

Continuing to follow the GEP logic and supply curve, we would estimate that, on an annual basis, the utility would need to reinvest in about 517 GWh of EE to maintain a higher level of savings. Again allowing costs to increase over time (in contrast with experience elsewhere) the aggressive approach requires an annual investment of about $260 million in 2017 and $630 million by 2032.

In total, an EE approach sufficient to replace all of Gallatin, Colbert, and unit John Sevier 3 by 2016 has a present value revenue requirement of about $6.0 billion from 2012 to 2032. The cost of retrofitting and maintaining the coal units is far higher - around $12.6 billion with no CO_2 price or $15.9 billion with a $21/t$CO_2$ cost for CO_2. On net, the EE program would save consumers between $5.8 and $9.1 billion, depending on the CO_2 future. In addition to these savings, the EE future is at lower risk of future regulatory requirements and fuel price shocks, avoids some transmission and distribution O&M costs, and frees up existing transmission for use in moving renewable energy elsewhere.

To support retrofits at Gallatin, Colbert, and John Sevier 3, we would expect average monthly residential bills to increase by about $5.80 per month in 2015 relative to today's bills (about 4.5% for the average customer), even in the absence of a CO_2 price. Conversely, the aggressive EE track would increase bills in the short term (maxing out at about $3.30 per month in 2014), but then decline to about a dollar per month above the baseline without EE and continues to drop from there. Energy efficiency thereby delivers customers savings of about $5 per month relative to the retrofit case in 2016 and 2017 (see **Figure 11,** below).

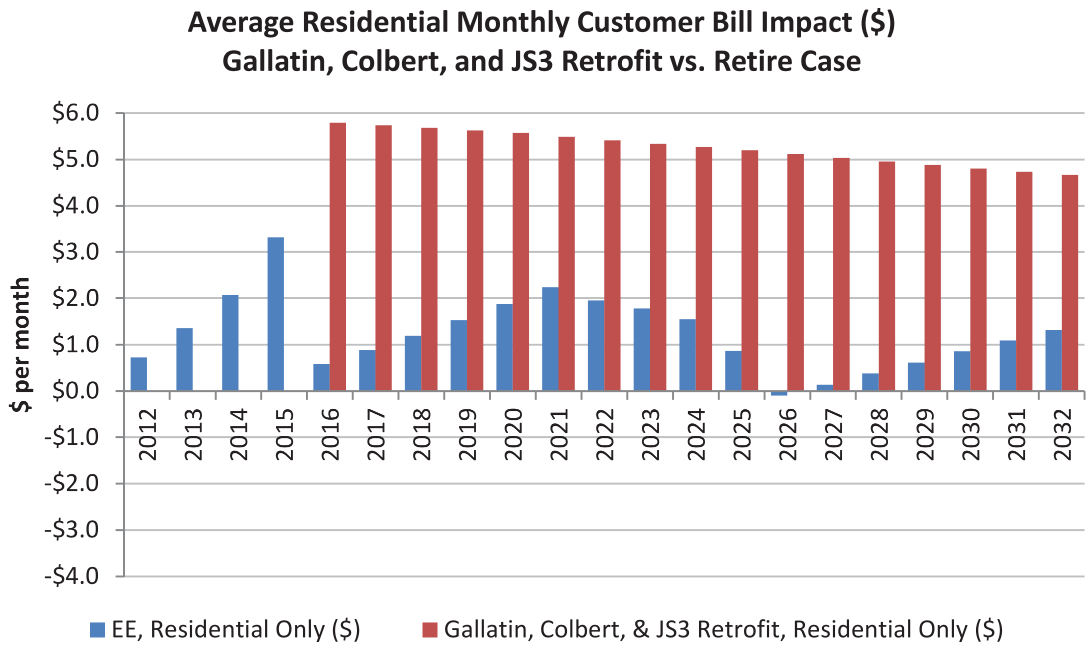

Figure 11. Average residential customer bill impact to fully retrofit the Gallatin and Colbert plants and John Sevier 3, including incremental O&M costs to operate FGD, SCR, and baghouse (in red); versus bill impact to achieve 2% savings per year, and maintain 2,750 MW of energy reduction by 2015 (in blue). Coal costs are exclusive of CO_2 price.

When CO_2 pricing becomes a reality, the economic case for aggressive efficiency will be even clearer. In this case, we would expect that the savings in avoiding payments for CO_2 cause the efficiency tract to realize significant bill savings of $2 per month in 2016. Overall, the 2% EE track saves nearly $8 per month for average residential consumers in 2016 (see **Figure 12,** below).

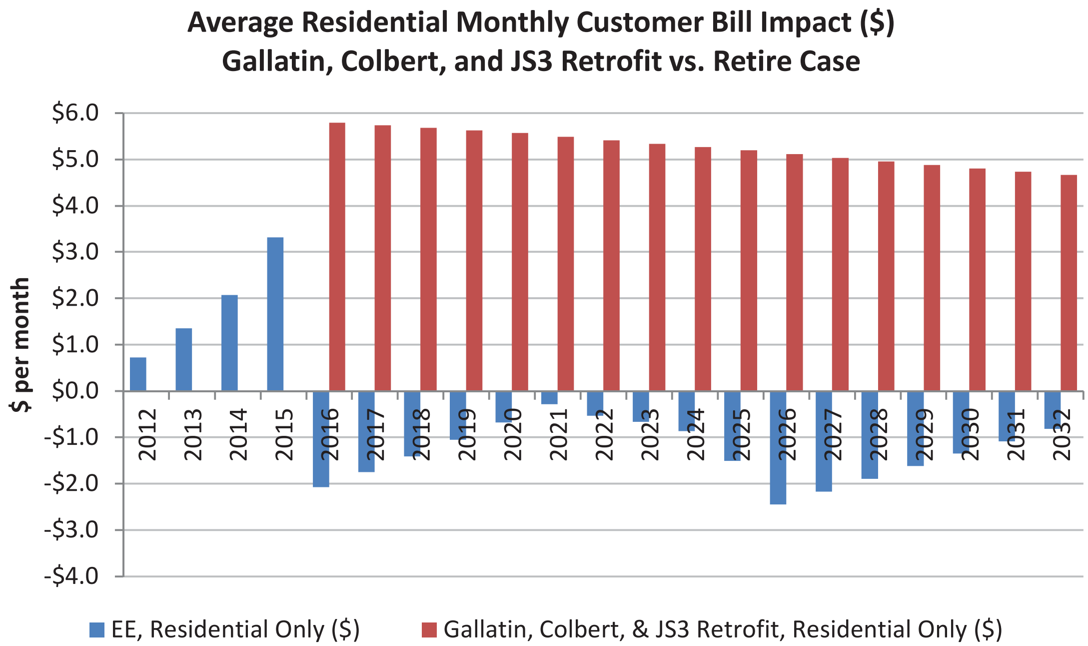

Figure 12. Average residential customer bill impact to fully retrofit the Gallatin and Colbert plants and John Sevier 3, including incremental O&M costs to operate FGD, SCR, and baghouse (in red); versus bill impact to achieve 2% savings per year, and maintain 2,750 MW of energy reduction by 2015 (in blue). Coal costs include levelized $21/tCO$_2$ price.

iii. *EE Savings Will be Even Greater After Correcting For Unrealistic Assumptions in the GEP Study*

Our analysis likely undercounts the cost savings of EE because the GEP study assumes a steep supply curve for energy efficiency – as deeper savings are achieved, the study assumes that these savings become incrementally more expensive. These assumptions are not realistic. For instance, the study assumes that in 2030, costs for the "high achievable" scenario would be five times more expensive than in 2015.[48] This trajectory is in marked contrast to the experience of utilities with well-established energy efficiency programs. In 2009, ACEEE reviewed the cost of saved energy in utility and third party programs from fourteen leading states, and concluded that average "utility costs" ranged from ¢1.5 to ¢3.4 per kWh, an average value of ¢2.5 per kWh.[49] Given that such leading states have operated their efficiency programs for the past few decades without experiencing the steep cost increases that GEP anticipates, this conclusion by the ACEEE study serves as a piece of strong evidence that program costs do not increase as GEP assumes.

Another study conducted by Synapse Energy Economics offers further support for this position, provided in **Figure 13**, below. [50] The study analyzed the costs and savings associated with EE programs for a total

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[48] GEP Study, Table 7-2. Cost of first-year savings in 2015 = $0.33/kWh, rising to $1.63/kWh in 2030.
[49] ACEEE 2009. Savings Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs, September 2009.
[50] Hurley D, K Takahashi, B Biewald, et al. 2008. Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts. http://www.synapse-energy.com/Downloads/SynapseReport.2008-08.0.MA-Electric-Utility-Energy-Efficiency.08-075.pdf

of 14 utilities or third party administrators since 2000, which are mostly running leading national efficiency programs. The figure shows about 90 data points, each of which represent a result of efficiency program activities in one year by one entity. The study revealed that there are economies of scale associated with more aggressive efficiency efforts: as percentage of energy saved increases, the cost of the efficiency programs declines. In other words, the study found negative supply curves where a per unit cost decease as the scale of a program expands, instead of GEP's positive supply curves where a per unit cost increase as the scale of a program expands.

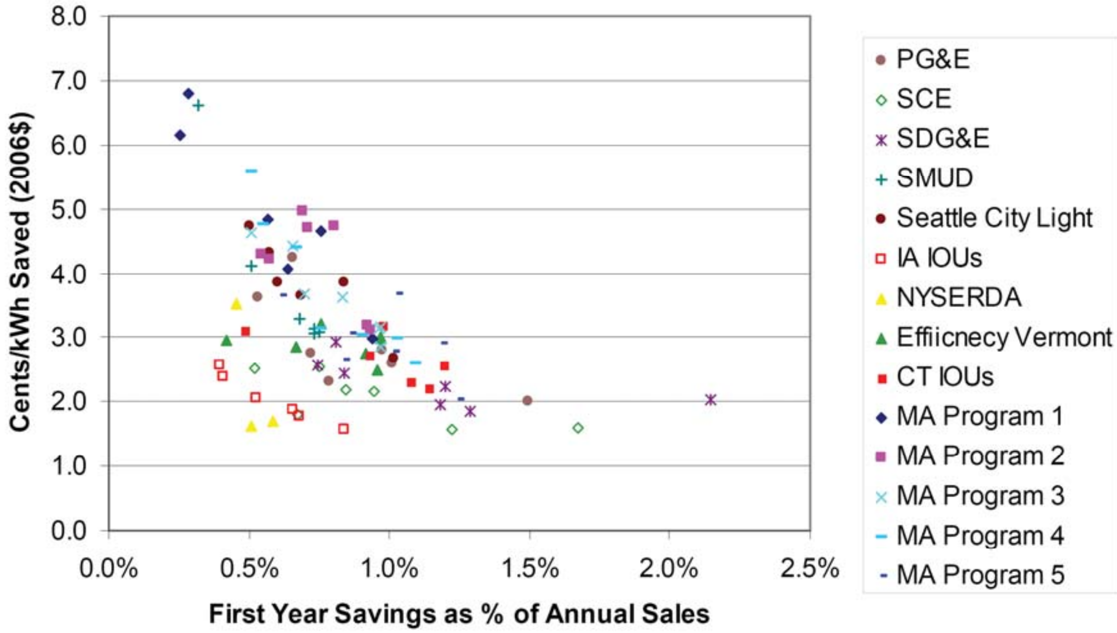

Figure 13. Recent historic data showing falling supply curve for EE programs; from real data, as penetration of EE programs increase, the cost per unit of EE falls. Graph shows cost of saved energy (c/kWh) versus annual incremental savings as a fraction of annual sales for 16 utilities or state programs between 1989 and 2006. ***Excerpted from Hurley D, K Takahashi, B Biewald, et al. 2008.***

Given this evidence that GEP is over-estimating long-term program EE costs, we reexamined our analysis with more realistic cost figures. To account for these dropping costs with increasing penetration, we conservatively assume a reasonable price cap for the cost of EE programs. This assumption is still fairly conservative: In essence, we considered the economics of EE where EE costs do not increase indefinitely, but instead only increase to a cap. To generate this cap, we reviewed the recent historic performance of leading utilities as in Figure 13. The weighted average lifetime CSE across these programs is around $2.4 cents or $0.024/kWh (2006$), or $0.025/kWh (2009$). As a conservative estimate, we tripled this, and assumed a high end lifetime CSE of around $0.06/kWh; we also again assumed that continued investment would be needed to maintain programs over time. With these assumptions, the first year CSE would be about $0.54/kWh at a real discount rate of 4.5%.

As a conservative estimate, we therefore assume a cap on first year CSE (that is, the cost of implementing an EE program in a given year) of $0.54/kWh at TVA. As mentioned above, GEP has assumed that this implementation cost increases as more efficiency potential is tapped – an assumption that does not match the experience of many EE providers..

Assuming that costs grow only to this level, we again considered the present value of a 2% EE program, compared with the costs of retrofitting the 2,750 MW of coal which that EE could replace by 2016. . Above, we had estimated the total present value (cost) of maintaining this level of savings through 2032 at $6.7 billion. Capping first-year CSE at $0.54/kWh results in a lower total present value cost of $6.0 billion. This means that, on net, the cost of the 2% EE program would be $6.5-$9.9 billion (depending on whether carbon costs are in place) less than the 2016-2032 cost of maintaining the Gallatin, Colbert & JS plant combination, rather than the $5.8 - $9.1 billion dollar benefit we estimated using GEP's assumptions.

The upshot is that EE likely produces even greater benefits than GEP assumes. But, as we have demonstrated, even on the conservative estimates supplied by the GEP study, EE is highly cost effective and can provide a direct replacement for some of TVAs coal units.

5. TVA's IRP Model Does Not Examine Economic Merit

Why has TVA thus far not seized the opportunity that EE presents? The answer likely lies in fundamental flaws in TVA's planning process. Clearly, there are numerous factors that determine if an existing generating unit should be maintained or retired in the face of mounting capital requirements and falling costs for alternatives. An accurate assessment of environmental regulatory risks and their incumbent costs is critical, as is a reasonable assessment of the costs of alternative fuels, generation strategies, and demand-side measures. For most utilities, these factors can be effectively assessed together in a reasonable Integrated Resource Plan (IRP) framework. While TVA did go through an apparently extensive IRP process in mid-2011, it lacked a clear description of the EE available to it and used a model framework which does not appear to allow for any assessment of the merit of existing generation. In particular, the IRP model either does not appear to allow coal units to retire in the face of economic pressure, or has significantly under-estimated the new costs facing these coal units.

The result was an IRP which did not prepare TVA to address these serious challenges. While other utility IRP from mid-2011 focus on the potential for coal retirement,[51] this discussion and analysis is conspicuously absent from the 2011 TVA IRP.

TVA used a proprietary tool called System Optimizer to model the IRP. Other utilities have demonstrated that this tool is capable of optimizing coal plant retirements in the face of increasing costs. However, the TVA IRP provides neither a platform to examine the economic retirement of coal resources, nor a mechanism to examine the cost-effective procurement of renewable energy or energy efficiency resources. Instead, DSM, renewable energy, and coal retirements are "hard coded" into the assumptions – that is, they are set in advance, rather than generated by the model – and only new resources are optimized.[52] Indeed, while the final form of the IRP suggests a "recommended" assumption of 4,000 MW of "idled" coal-fired capacity, it is not at all clear which units are included in this trajectory, or if the avoided

[51] See, for example: Duke Energy Ohio 2011 Long-term forecast report and resource plan (July, 2011 – 11-1439-EL-FOR); Georgia Power Company's Updated IRP (August, 2011 – Docket 34218); PacifiCorp 2011 IRP (March 31, 2011 – see p180); and American Electric Power 2010 AEP-East IRP (December, 2010)

[52] In the correct use of an optimization model, all resources would be available for the model to either choose or shed – if a lower cost portfolio requires removing existing resources, such a plan should be allowed. It appears from TVA's use that the utility has not allowed the model to choose which coal units are retired, but instead chooses a trajectory a priori.

costs of environmental compliance have been taken into account when examining these idled units.[53] Rather, it appears that even at high CO_2 prices, prices that would certainly force non-economic units to retire in the future, TVA simply accepts that their coal units will incur these costs instead of seeking alternative generation resources. Such significant design flaws suggest that TVA has not sufficiently examined the economic retirement of its coal units, particularly in relationship to a reasonable replacement portfolio of DSM, renewable energy, and alternative generation resources.

The result is that TVA is not on track to meet its mandate to provide the lowest power prices to its customers. But TVA need not continue on this course. Now that it has assessed its EE potential, it can begin to move rapidly to change course. TVA has the opportunity to use the System Optimizer tool effectively to examine the economic merit of its coal units in the face of new capital and environmental requirements, limits on CO_2 emissions, Clean Energy Standards (CES) or Renewable Energy Standards (RPS), opportunities for deep energy savings through demand-side management, and falling natural gas prices. An effective use of the model would illustrate clearly which units should be retired and replaced. We expect that a large fraction of the TVA coal fleet would, when properly modeled, appear clearly non-economic.

6. Conclusions

TVA's coal fleet is reaching a crisis point. We estimate that a majority (64%) of TVA's coal capacity is non-economic relative to long-term market replacement costs. With environmental regulatory compliance deadlines only four years out, TVA should be examining retiring and replacing its non-economic coal units now. The utility has a variety of options for replacing these units. We have shown here that energy efficiency could cover the requirements of at least two of the highest cost coal plants by 2016 at significant net cost savings to the utility. Local and transmitted renewable energy PPAs, market purchases, and new generation resources if required could cover a significant fraction of other requirements rather than pursuing retrofits at coal units.

TVA has both the opportunity and responsibility to aggressively search for alternatives to its non-economic coal fleet. Under a standard regulatory regime (i.e. if TVA reported to a Public Service Commission), the utility would almost certainly be unable to justify any retrofits at its non-controlled coal units – the economics can simply not be supported. TVA's 2011 IRP does little to support the continued use of TVA's older coal units. The IRP presents several fatal flaws even before an examination of its underlying assumptions and inputs.

If TVA neglects to examine opportunities for economic retirement today, we estimate that the utility will be effectively committing to $11.8 billion of capital investments in the next decade, and billions more in unnecessary increases in O&M costs. Simply examining opportunities to accelerate, expand, and bring to the forefront the utility's demand-side management and energy efficiency programs could quickly alleviate

[53] One critical error in some IRPs that examine coal-retirements is the failure to credit a retirement scenario with the avoided capital and operational cost of implementing and running new environmental controls. If the capital costs of building new controls are assumed to be a foregone "baseline" cost, and then even in a planning exercise, these costs would be considered as sunk costs, and there would be little or no merit to consider retiring a unit for environmental compliance purposes.

the requirement for at least two highly non-economic coal units) at significant net cost savings to the utility, and start lowering customer bills in the next two years.

By driving down demand through aggressive energy efficiency, and pursuing alternative generation resources (such as local and imported renewable energy), TVA could quickly pivot its portfolio from a heavy dependence on carbon-intensive coal to a national leader in efficiency and a driving force behind the growth of renewable energy in the South.

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.

January 23, 2011

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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

[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.

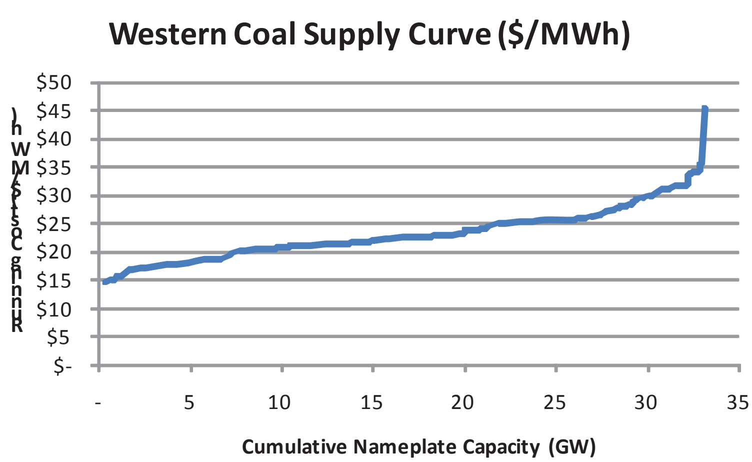
In this analysis, we use assumptions from the NERC 2010 Reliability Assessment to estimate fixed and variable O&M costs.[9] Costs are categorized with economies of scale based on the capacity of the plant. Assumed O&M costs are given in **Table 1,** below.

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.



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[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)

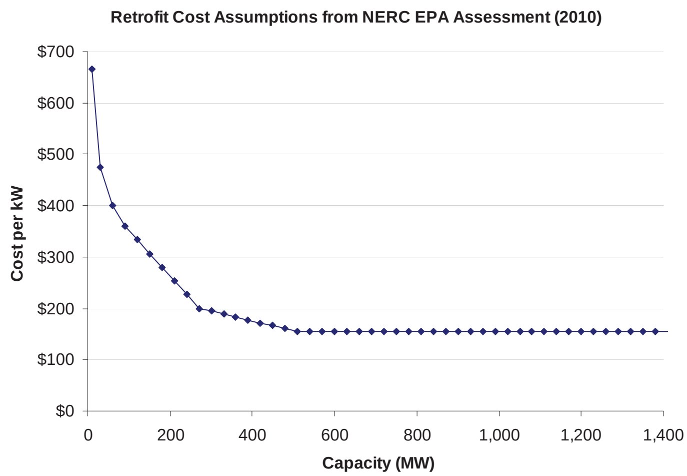

Figure 2. NERC cost curve for wet cooling towers.

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.

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[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.