**October 13, 2006**

**United States District Court for the Western District of North Carolina**
**Asheville Division**

State of North Carolina, ex rel., Roy Cooper, Attorney General, Plaintiff

v.

Tennessee Valley Authority, Defendant

**Expert Report**

I, James E. Staudt, have been retained by the Attorney General of the state of North Carolina as an expert in the field of air pollution control from power plants. This report documents my findings regarding the control devices that could be applied to the Tennessee Valley Authority's (TVA) coal-fired units and the estimated cost associated with those controls for TVA to comply with an emissions cap equivalent to that required of power plants affected by North Carolina's Clean Smokestacks Act.

## I. BACKGROUND AND QUALIFICATIONS

I am the President of Andover Technology Partners ("ATP"). As President of ATP, I have advised power plant owners, equipment suppliers and government agencies on the cost and performance of power plant air pollution control technology. For nearly twenty years, I have worked in the field of air pollution control technology. For the past nine years (since 1997) I have been a consultant with my own business – Andover Technology Partners. My primary area of business as a consultant is associated with my expertise relating to the performance and cost of air pollution control technologies on power plants. Clients have included the US EPA, power plant owners, technology suppliers, and others. I have published several papers and reports, including papers in peer-reviewed journals and reports issued by the US EPA relating to the performance and cost of power plant air pollution controls. Several of these papers have been coauthored with staff of the US EPA. For most of the period from 1988 to 1997 I was employed by companies that supplied air pollution control technology (Research Cottrell and Fuel Tech) or power plant and refinery gas analyzers (Spectrum Diagnostix, a subsidiary of Physical Sciences that was acquired by Western Research). As an employee of these companies over this period I sold, designed, and commissioned air pollution control technology at numerous power plants and industrial facilities.

I received my M.S. (1986) and Ph.D. (1987) in Mechanical Engineering from the Massachusetts Institute of Technology. I received my B.S. in Mechanical Engineering from the U.S. Naval Academy in 1979. From 1979 to 1984 I served as a commissioned officer in the U.S. Navy in the Engineering Department of the nuclear-powered aircraft carrier USS ENTERPRISE (CVN-65).

A list of my publications and prior testimony is provided as an attachment to this report.

**Summary of Testimony**

The Tennessee Valley Authority's (TVA) coal-fired power plants are capable of meeting emissions caps that are equivalent to those that are required of Duke Energy and Progress Energy power plants by North Carolina's Clean Smokestacks Act (CSA). In this analysis, system-wide caps were estimated for TVA's coal units that are equivalent to the CSA caps that apply to Duke Energy and Progress Energy power plants in North Carolina.

I considered how TVA might achieve the emission reductions necessary to meet these caps through implementation of emissions control technology on their existing plants. I expect the control technology applied to existing plants to include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) on select units for NOx control. For $SO_2$ control, I expect that Limestone Forced Oxidation (LSFO) wet scrubbers would be installed on most units. In this analysis it is assumed that LSFO systems currently installed achieve the current outlet emissions rates in the future. If the existing LSFO units can be optimized to achieve lower emissions rates – I expect that fewer new LSFO systems would be required to achieve the CSA equivalent emissions rate. Increased use of NOx and $SO_2$ emissions control technology will have the added benefit of reduced mercury emissions.

As a result of installing control equipment to achieve at or below CSA equivalent emissions, I estimate that TVA's 2013 emissions would be reduced in 2013 by about 70% for $SO_2$, 48% for NOx and 54% for mercury compared to TVA's Base Case 2013 emissions, as shown in Tables S.1 and S.2 and Figure S.1.

**Table S.1.** Estimated 2013 TVA emissions and emissions reduction due to CSA equivalent emissions cap

| | **$SO_2$** | **NOx** | **Hg** |
|---|---|---|---|
| **Emissions Units** | Tons per year | Tons per year | Pounds per year |
| **Base Case Estimate** | 448,916 | 115,144 | 2,917 |
| **CSA Equivalent Estimate** | 137,015 | 59,515 | 1,333 |
| **Reduction in Emissions** | 311,901 | 55,629 | 1,584 |
| **Percent Reduction in Emissions** | **69.5%** | **48.3%** | **54.3%** |

I have estimated that the total capital cost of the retrofit program for TVA to meet the CSA equivalent emissions rates for NOx and $SO_2$ will be about \$3 billion (in 2006 dollars). As shown in Table S.3, most of this cost is associated with the cost of $SO_2$ controls. Actual costs realized will differ based upon site-specific factors that determine the difficulty of the retrofits, market pricing of material and labor, and other factors. The capital cost will also be impacted by the actual choices TVA makes and how they mirror those assumptions described herein. For example, if TVA is able to reduce the outlet emissions of the existing scrubbers at Paradise to make them comparable to state-of-the-art controls, then it will be possible to avoid installation of scrubbers on some smaller units, and thereby eliminate the cost associated with the avoided scrubbers. The increased operating cost of the program is estimated to be in the range of \$220 million per year (in 2006 dollars). Operating costs can generally be estimated with somewhat more precision than capital cost because these are estimated through engineering calculations based upon unit characteristics that are available.

**Table S.2.** Estimated 2013 TVA plant-by-plant emissions and projected technology

| Plant | Projected Technology | 2013 Base Case | | | 2013 CSA Equivalent | | |
|---|---|---|---|---|---|---|---|
| | | NOx | $SO_2$ | Hg | NOx | $SO_2$ | Hg |
| **Allen Steam Plant** | **SCR, FGD** | 2,233 | 24,920 | 195 | 2,233 | 4,070 | 28 |
| **Bull Run** | **SCR, FGD** | 2,295 | 33,851 | 27 | 2,295 | 4,341 | 4 |
| **Colbert** | **SCR, FGD** | 11,972 | 35,802 | 236 | 2,331 | 5,954 | 34 |
| **Cumberland** | **SCR, FGD** | 6,871 | 20,396 | 259 | 6,871 | 20,396 | 259 |
| **Gallatin** | **SCR, FGD** | 10,944 | 27,387 | 301 | 1,933 | 5,799 | 43 |
| **John Sevier** | **SCR, FGD** | 11,504 | 34,158 | 331 | 1,495 | 4,132 | 47 |
| **Johnsonville** | **SNCR, FGD** | 22,897 | 82,181 | 308 | 17,173 | 6,828 | 176 |
| **Kingston** | **SCR, FGD** | 3,118 | 62,660 | 460 | 3,118 | 8,417 | 66 |
| **Paradise** | **SCR, FGD** | 8,406 | 50,116 | 321 | 8,406 | 50,116 | 321 |
| **Shawnee** | **SNCR, SCR, FGD** | 20,818 | 41,146 | 190 | 10,305 | 9,796 | 190 |
| **Widows Creek** | **SCR, FGD** | 14,087 | 36,299 | 291 | 3,355 | 17,166 | 166 |
| **Total** | | **115,144** | **448,916** | **2,917** | **59,515** | **137,015** | **1,333** |
| NOx and $SO_2$ emissions in tons per year, Hg emissions in pounds per year | | | | | | | |

**Figure S.1.** Estimated 2013 TVA Base Case emissions and emissions with CSA equivalent emissions cap

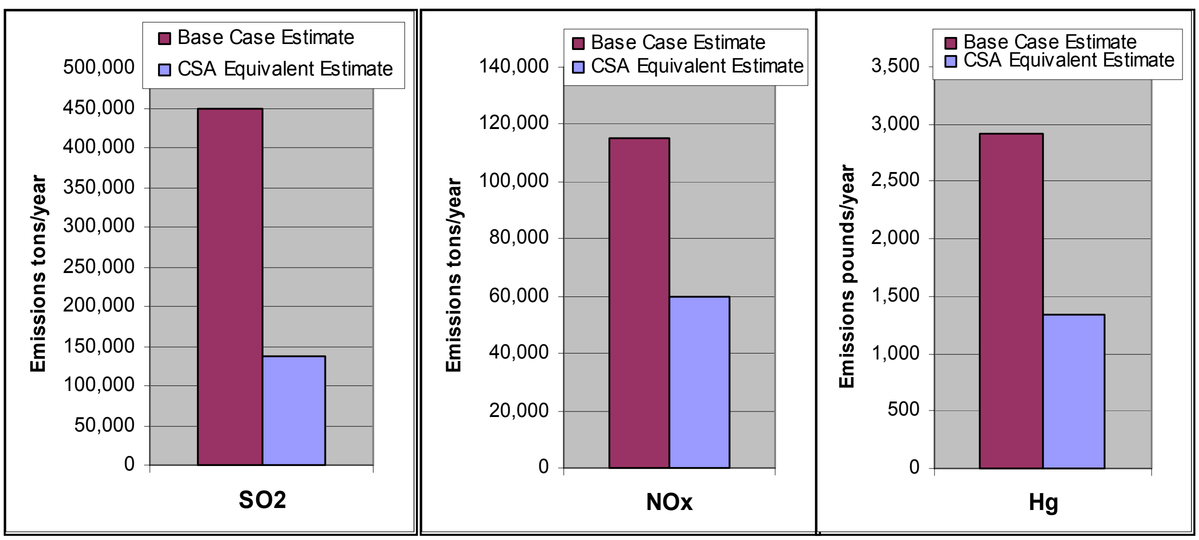


**Table S.3.** Estimated Costs of Control Technology for CSA Equivalent over Base Case

| | |
|---|---|
| **Capital Cost, $1000** | |
| FGD Capital Cost | $2,202,714 |
| SCR/SNCR Capital Cost | $763,718 |
| **Total Estimated Capital Cost, $1000** | **$2,966,432** |
| | |
| **O&M Costs, $1000/year** | |
| FGD | $191,884 |
| SCR/SNCR | $29,937 |
| **Total O&M, $1000/year** | **$221,820** |

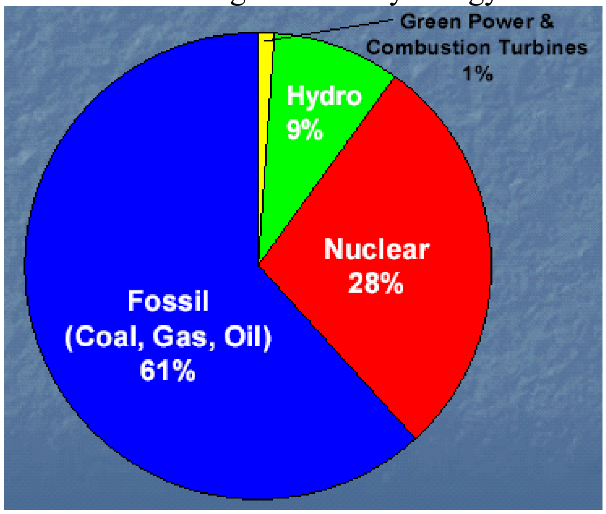
In this report I will address the following:

- Provide an overview of the TVA system.
- Provide an overview of how power plants operate.
- Provide an overview of how power plant pollutant emissions are controlled, with special attention to the technologies that I expect will play an important role in reducing emissions from existing TVA coal-fired units.
- Discuss how the CSA Equivalent emission caps for NOx and $SO_2$ were determined for TVA.
- Discuss how I expect TVA might comply with the CSA Equivalent emission caps and what I expect it will cost.

## Overview of TVA System

The TVA system includes 3 nuclear plants, 11 coal plants, 29 hydroelectric dams, 6 combustion turbine sites, and 1 pumped storage plant. Its green power program includes 16 solar sites and one wind energy site. Figure 1 shows the relative breakout of generation by energy source. TVA is heavily dependent upon fossil and particularly coal generation.

**Figure 1.** Breakdown of 2005 TVA generation by energy source[1]




TVA operates thirteen fossil power plants, eleven of them are coal. Eight of TVA's fossil plants are in Tennessee, with two in Kentucky (Paradise and Shawnee) two in Alabama (Colbert and Widows Creek), and one (Kemper) in Mississippi. Kemper and Lagoon Creek are combustion turbine plants, and the balance of TVA's fossil generating capacity is primarily coal-fired.

At over 15,000 MW, TVA operates one of the largest coal-fired generating fleets in the world. In the United States, only American Electric Power Corporation (AEP) and Southern Company operate larger coal-fired fleets over large, multi-state regions. Even the combined Duke-Cinergy coal fleet is smaller than that of TVA. But, unlike these other systems that are spread over several states, all of TVA's coal-fired generating plants are within the state of Tennessee or just over the border in adjacent states, Alabama and Kentucky. The locations of the coal-fired plants are shown in Figure 2.

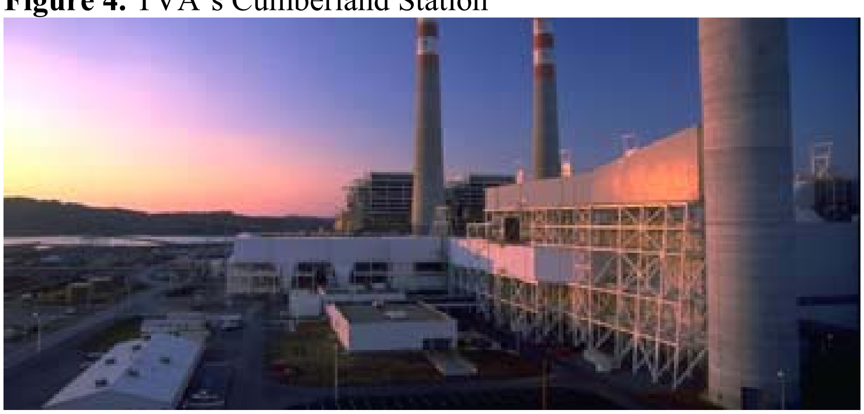
**Figure 1.2.** Location of TVA Coal-Fired generating plants[1]

TVA's large coal fleet means that it is also one of the highest emitters of $SO_2$ and NOx in the United States. Other owners of large coal fleets are investing in environmental controls. According to AEP's web site, AEP has invested nearly $1.3 billion in equipment retrofits to reduce NOx emissions. By 2010, AEP states that it will have invested an additional $4 billion in capital in scrubbers and SCR systems to reduce $SO_2$ and NOx emissions.[2] According to Southern Company's web site, Southern Company will commit $3.1 billion over the next three years to add additional environmental controls, which will further lower emission of $SO_2$, NOx and mercury.[3] This is in addition to Southern Company's $1.4 billion investment in NOx control. According to Duke Energy's web site, Duke Energy has invested over $1.5 billion in NOx controls since 1998 and is investing nearly $3.5 billion more to further reduce both NOx and $SO_2$ emissions.[4] And, according to their web site, Progress Energy is investing more than $800 million in capital costs to comply with the Clean Smokestack Act's requirements. These investments are in addition to the $370 million investment the company has made to reduce NOx emissions.[5]

TVA's system has a large number of boilers 200 MW or less in size, while it also has some of the largest boilers in the country. Of the 59 coal-fired units in TVA's fleet, 43 have capacities of 200 MW or less. Johnsonville, a plant with ten units under 200 MW is pictured in Figure 3. At the other end of the spectrum are some extremely large units. Cumberland, with two units at 1300 MW each, has two boilers that are among the very largest in the United States. Photos of other TVA plants are shown in the Appendix.

**Figure 3.** TVA's Johnsonville Station [6]

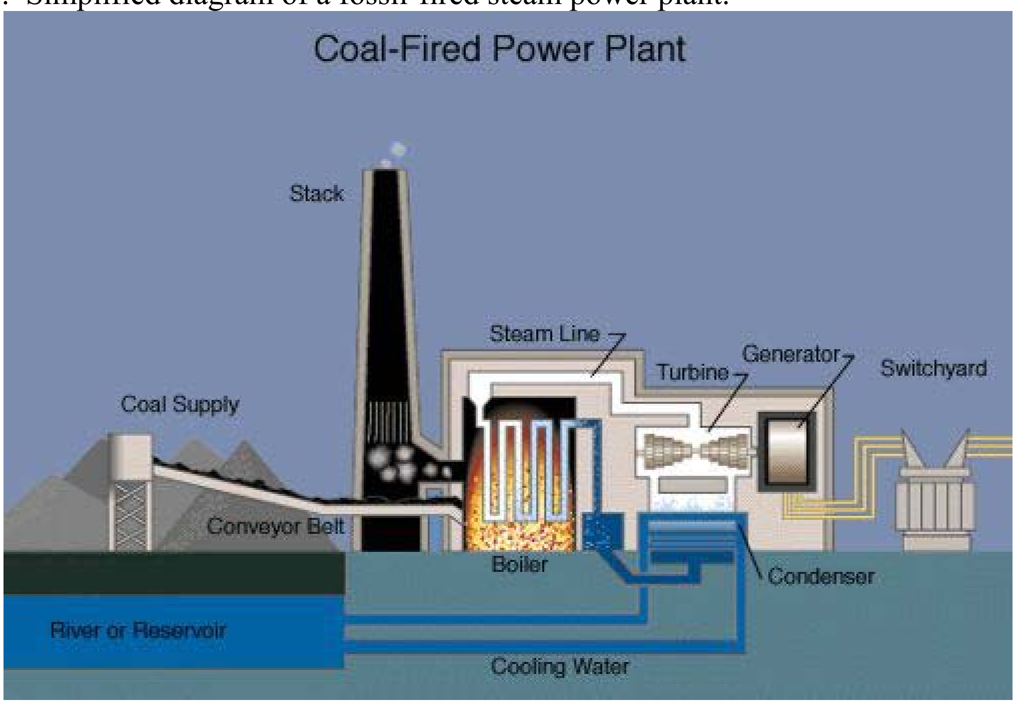
**Figure 4.** TVA's Cumberland Station[6]



## Overview of Power Plants

About half of the electricity generated in the United States is from coal-fired power plants. For this reason, coal-fired plants are an important part of America's energy infrastructure. Figure 5 shows a simplified diagram of how a fossil-fired boiler (coal, oil, natural gas) generates electricity through a steam cycle that engineers call the Rankine Cycle. Starting from the left, coal and air are combined in a furnace to form a flame that releases the chemical energy bound in the fuel as heat. The exhaust from the flame is comprised of combustion products – nitrogen, water vapor, carbon dioxide, other gases and sometimes particle matter that are released to the atmosphere through a smoke stack. In the boiler, the heat from the flame is used to heat water to generate steam at a high pressure. This high pressure steam is used to power a turbine that drives a generator to produce electricity. The steam exhausts from the turbine at lower temperature and pressure and is cooled even further to condense to water. Cooling water normally flows through the condenser to cool the steam to water. But sometimes the condenser is cooled with air. The condensed water is then pumped back to the steam generator at high pressure to be re-heated to steam.

**Figure 5**. Simplified diagram of a fossil-fired steam power plant.[6]




Of interest with regard to pollution control are the combustion products that escape from the furnace. Nitrogen and water vapor, of course, are benign products. Carbon dioxide is an emission that is not currently regulated in the US except in some locations. Particle Matter (PM) is certainly of concern with regard to air pollution and all coal-fired power plants have PM control devices (although not shown in Figure 1 above) in order to capture the PM before it is released up the smokestack. Also of concern with regard to air pollution control are emissions of other gases such as oxides of nitrogen (denoted as NOx), oxides of sulfur (primarily $SO_2$ but to a lesser extent $SO_3$), mercury, carbon monoxide, and other gases. Since the CSA is focused on NOx and $SO_2$ and has implications for mercury, we will focus attention on these pollutants.

NOx, is in the form of NO (nitrogen oxide) or $NO_2$ (nitrogen dioxide). It is formed when the fuel burns. The two major sources for NOx during coal combustion are: oxidation of nitrogen in the combustion air at high flame temperatures, and; oxidation of nitrogen in the fuel. NOx contributes to acid rain, it contributes to ground level ozone (smog), and it contributes to fine particle matter. Its contribution to fine PM and ground-level ozone are causes for health concerns and are why North Carolina requires a reduction in NOx emissions in the Clean Smokestacks Act. NOx may be controlled by combustion controls – which reduce the amount of NOx that is formed in the flame - and also by post-combustion controls – which convert the NOx in the exhaust gas to benign gases like nitrogen and water. Combustion controls are usually less expensive than post-combustion controls. However, combustion controls are not alone adequate to meet the emissions requirements of NC's CSA. So, when more stringent requirements are imposed, post-combustion controls are used – often in combination with combustion controls - to meet those limits.

$SO_2$ and $SO_3$ result from oxidation of the sulfur in the coal, and normally most of the sulfur oxidizes to $SO_2$ with only a small amount oxidizing to $SO_3$. These pollutants contribute to acid rain and to fine PM. The contribution of $SO_2$ to fine PM is a cause for health concerns and is a principal reason why North Carolina requires a reduction in $SO_2$ emissions in the Clean Smokestacks Act. $SO_2$ emissions are controlled by either limiting the amount of sulfur in the coal or by installing scrubbers that remove the $SO_2$ from the exhaust gas stream.

Mercury exists in trace amounts in coal and is released through combustion. Mercury is a toxic material that after release to the environment can accumulate in lakes and streams and concentrate in fish, making the fish unhealthy to eat. Fortunately, mercury is captured to some degree in pollution control equipment designed to capture PM and $SO_2$. And, when NOx control equipment is used in combination with $SO_2$ scrubbers, mercury capture from all of the pollution control equipment can be very high – about 90% or more. This capture of mercury by equipment designed to capture other pollutants is often called "cobenefit" reduction of mercury. Because of the NOx and $SO_2$ controls that will be used on Duke and Progress Energy plants in response to the CSA, high cobenefit removals of mercury are expected.

TVA can reduce the emissions from its fossil fleet in one or more of the following ways - used in combination or separately:

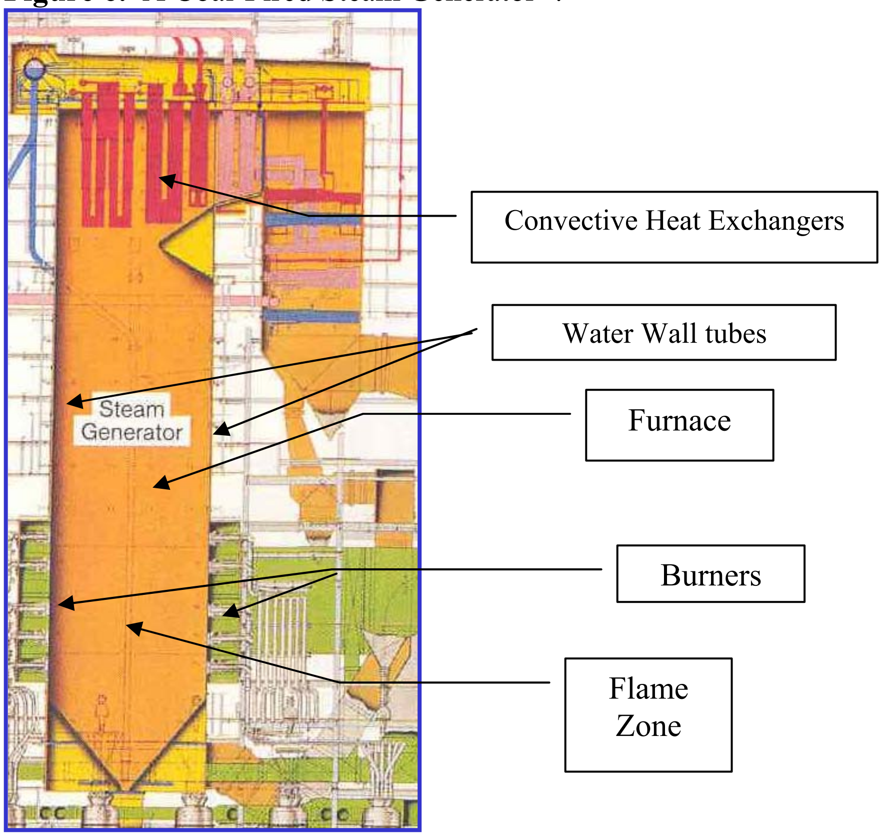
1. TVA can install control technology on its existing fossil units.
2. TVA can replace some of its older, less efficient fossil units with newer, more efficient and lower emitting fossil units.
3. TVA could increase it's use of low sulfur coals.
4. TVA could substitute generation from other sources for coal generation.

In the following section we will examine the types of controls that TVA might implement on its existing units.

## Air Pollution Control Technologies

The steam generator or boiler is where the chemical energy of the fuel is converted to useful high pressure steam. The combustion exhaust gases leave the furnace and transfer their heat to water or steam that is at high pressures within steel tubes that are in the furnace wall or suspended in the gas stream as part of convective heat exchangers. The transfer of heat from the exhaust gases to the water has the effect of cooling the exhaust gases as the water and steam within the tubes heat up. Figure 6 shows the parts of a modern steam generator.

**Figure 6.** A Coal-Fired Steam Generator [7].

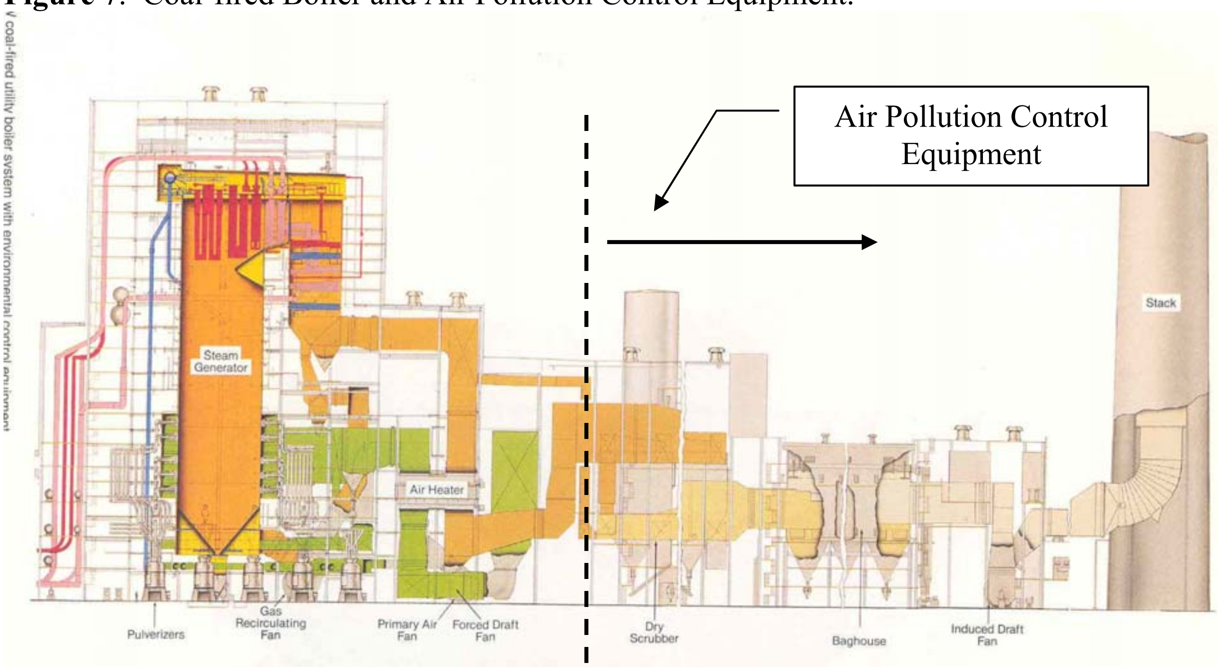



After the exhaust gases leave the steam generator, they must be treated to remove pollutants. In Figure 7, all of the equipment to the right of the dashed line is primarily for the purpose of air pollution control, and these are exhaust gas treatment controls. Exhaust gas controls remove pollution in the gas stream after the fuel is burned and in most cases after the exhaust gases leave the furnace. On the other hand, some air pollution control – particularly for controlling NOx - is integrated with the boiler, as will be discussed later. The size of the air pollution control equipment is usually dictated by the volume flowrate of exhaust gas and the amount of time that the device requires to treat the gas.

*Methods for Controlling NOx*

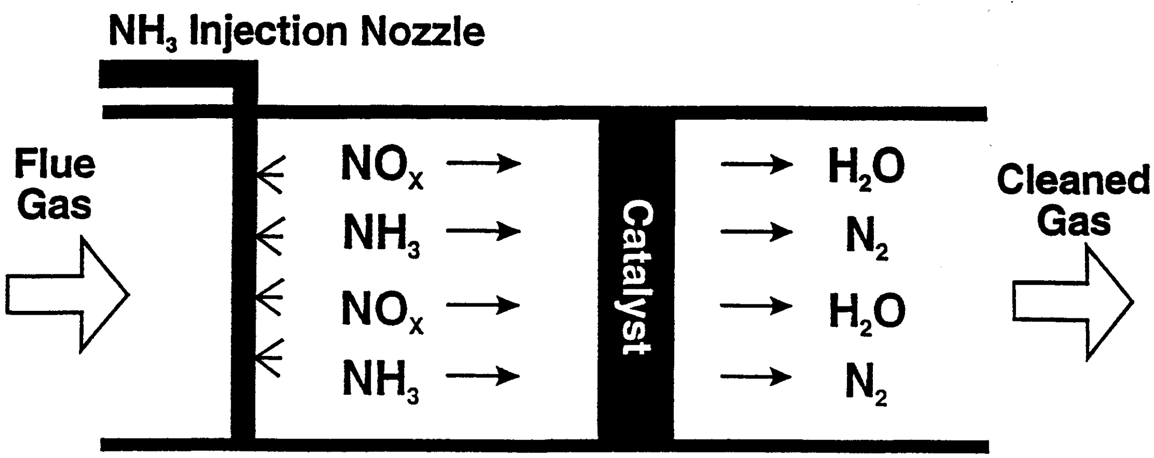
*Combustion Controls -*
As noted earlier, combustion controls are frequently the first choice for NOx control because they are lower in cost in most cases than post-combustion controls. Combustion controls reside within the boiler itself and include such methods as low NOx burners (LNB) and over-fire air (OFA). Achieving thorough combustion of the coal and achieving low NOx emissions are often competing objectives. So, there are practical limits to what can be achieved with combustion controls. LNBs and OFA reduce NOx formation by carefully controlling the combustion process in such a way that NOx formation is minimized while still providing good combustion. Computer software is also often used to help improve the operation of the combustion controls and maintain operation at the "optimal" point. However, combustion NOx controls are inadequate for achieving very low NOx emissions. So, post-combustion controls are also necessary to achieve very low emissions of NOx. Combustion NOx controls and post-combustion NOx controls can, and often are, used in combination.

**Figure 7**. Coal-fired Boiler and Air Pollution Control Equipment. [7]



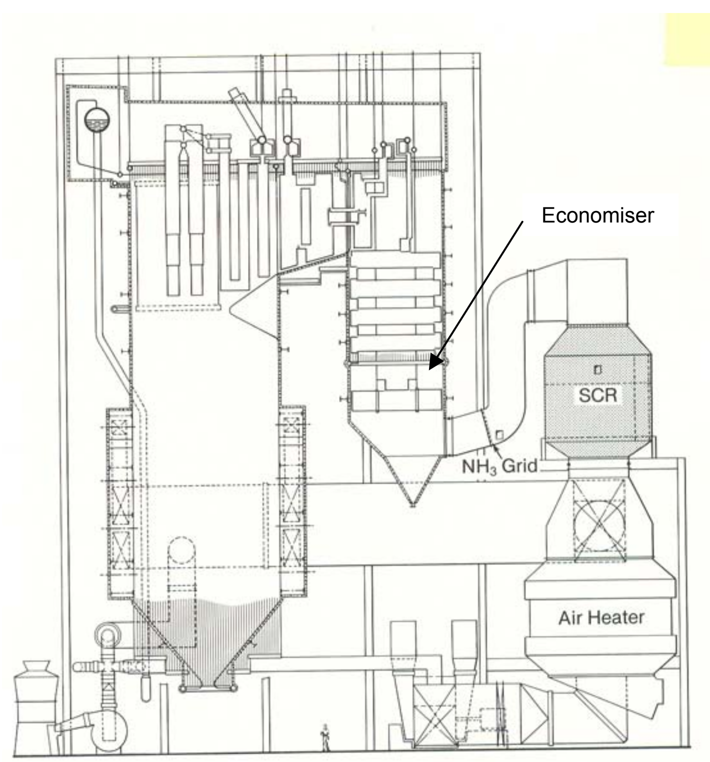

*Selective Catalytic Reduction (SCR)*
SCR is a post-combustion NOx control technology that is capable of providing 90% or more removal of NOx. About one third of the total coal-fired generating capacity in the US is equipped with SCR, and more SCRs are planned for existing units. Also, SCR is necessary on all new coal-fired power plant boilers to achieve requisite emission rates. The high level of NOx reduction available with SCR is achieved by reacting ammonia with NOx in the presence of a catalyst in a temperature range of about 600°F-700°F. The ammonia is introduced through a series of pipes, or a grid, upstream of the SCR catalyst bed. Figure 8 shows a simplified process diagram of an SCR system. The chemical reaction between ammonia and NOx that occurs on the surface of the catalyst results in the formation of molecular nitrogen and water. Some of TVA's units are currently equipped with SCR and they are operated on a seasonal basis to reduce NOx in the summer months – the Ozone Season – from May through September.

**Figure 8.** Simplified diagram of the SCR process [8]




The SCR reactor is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler as shown in Figure 9. Retrofitting SCR usually requires an outage of about a month in order to install the equipment because ductwork must be modified, which can't be done with the unit on line. If possible, the equipment is erected with the unit on line, but duct modifications or relocation of existing boiler equipment are performed during an outage. When retrofitting SCR, it is desirable to make these modifications during a regularly scheduled outage in order to avoid or at least minimize the need for another outage.

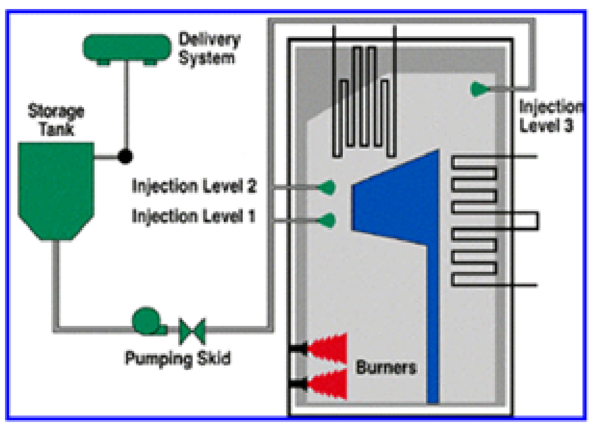
**Figure 9.** An SCR System on a coal-fired boiler [7]



A typical capital cost of SCR is in the range of about $100/KW-$120/KW with a wide variation about this average because of the range in difficulty that may be associated with an SCR retrofit. For example, in TVA's Response to Interrogatory No. 8, they reported their SCRs to cost in the range of around $63/KW to about $220/KW. Operating cost includes ammonia reagent, periodic catalyst replacement, parasitic power mainly due to the pressure drop across the SCR system and the attendant increased fan load, and fixed operating costs. The expected useful life for an SCR system is in the range of 30 years or more.

*Selective Non-Catalytic Reduction (SNCR)*
SNCR is another post-combustion NOx control technology. It typically achieves in the range of 25%-30% NOx reduction. SNCR reduces NOx by reacting urea or ammonia with the NOx at temperatures around 1800°F-2000°F. The urea or ammonia is injected into the furnace post-combustion zone and, like SCR, reduces the NOx to nitrogen and water. The capital cost of SNCR is less than that of SCR – in the range of about $15-$20/KW – or about $4 million or less for a 200 MW plant. The operating cost of SNCR is primarily the ammonia or urea reagent. SNCR is most commonly applied to smaller boilers because the economics of SCR are usually more favorable than SNCR on large boilers. When emissions regulations permit averaging or trading of NOx emissions among units under a common cap, installing an SCR on a large boiler allows utilities to overcontrol the large unit and use less costly technology, such as SNCR or combustion controls, for NOx control on smaller units.

**Figure 10.** Simplified diagram of an SNCR system. [9]




The SNCR equipment is fairly simple and limited in size – consisting of a storage tank, pumps, piping, and injection hardware, as shown in Figure 10. The only major interfaces with the boiler are the injector penetrations in the furnace wall, as indicated in Figure 10. Except for these penetrations, all other SNCR installation activities can be performed with the unit on line. Installation of the furnace wall penetrations may take a few days to a week. So, this can be easily integrated into a plant's scheduled outages.

***Controlling $SO_2$ Emissions***

*Lower Sulfur Fuel*
Changing to lower sulfur fuel is a frequently used approach for reducing $SO_2$ emissions. Some coal may be naturally low in sulfur, such as the coal that comes from the Powder River Basin (PRB). This PRB coal is shipped from Wyoming. As a result, availability and cost of transport of this fuel may be limiting factors for plants nearer the east coast. It is also possible to wash higher sulfur coal to reduce the sulfur content. This is frequently done with eastern coals. Washing has the other beneficial effect of reducing coal ash and mercury content. However, washing the coal adds expense and generates a solid and liquid waste that must be dealt with at the site where washing occurs. Since fuel cost is the most significant ongoing cost for a power

plant, the ability to use lower cost fuels may cause plant-owners to consider the expense of flue gas desulfurization (FGD) equipment to permit them more fuel flexibility while maintaining low $SO_2$ emissions. So, economic factors may cause a power plant owner to consider FGD. Another factor that will cause a power plant owner to consider FGD is that emissions requirements may be sufficiently stringent that low sulfur coal alone is not adequate and that FGD will be necessary. This is the case with the CSA $SO_2$ control levels – which require Duke and Progress to install $SO_2$ controls on many of their units. Moreover, all new coal-fired power plants must have some form of FGD. There are two basic forms of FGD, dry and wet.

*Dry FGD*

A Dry FGD was shown in the power plant schematic in Figure 7. Dry FGD is often called a dry scrubber or Spray Drier Absorber, or a Lime Spray Drier. In a dry FGD system lime slurry is sprayed into the flue gas in reaction vessel to give the gas and lime time to interact. The lime (CaO) reacts with the $SO_2$ to capture it. The term "dry" refers to the fact that although water is added to the flue gas, the amount of water is enough to cool the gas but not so much as to drop it below the saturation (or, dew point) temperature. So, the humidity of the gas is increased but not so much that water droplets form. In most cases the $CaSO_3$, $CaSO_4$ products and any unreacted lime from the dry FGD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of $SO_2$. Dry FGD is usually only used on lower sulfur applications because the reagent, lime, is more expensive than reagents available for wet FGD. Lime is a material that is produced in a kiln from limestone, and it is therefore more costly than limestone – the most commonly used reagent for wet FGD. For higher sulfur applications, wet FGD is considered more economically attractive.

*Limestone-Forced Oxidation (LSFO) wet scrubbers*

There are different forms of wet FGD. But, LSFO is the most widely used form of wet FGD. State of the art LSFO systems are capable of providing very high levels of $SO_2$ removal - on the order of 98% or more. TVA currently uses LSFO technology to reduce $SO_2$ emissions at the Cumberland plant, at two of the Paradise units (a third should soon be in operation), and on two Widow's Creek units. The technology operates by reacting a limestone slurry with the flue gas in a large absorber vessel to capture the $SO_2$ that passes through the absorber, as shown in Figure 11. The reacted limestone and $SO_2$ form a gypsum by-product. In the absorber (Figures 12a and 12b) the gas is cooled to below the saturation temperature, resulting in a wet gas and high rates of capture that can be in the range of 98%-99%. The gypsum by-product is typically used in the manufacture of wallboard that is sold to the construction industry.

According to TVA's Response to Interrogatory No. 8, the LSFO systems at Cumberland are reported to have cost $280 million each, or about $215/KW in 1995. And, the new LSFO at Paradise unit 3 is expected to cost about $190/KW. The scrubbers at Paradise units 1 & 2 and Widows Creek units 7 & 8 were nominally less expensive, but were built 20 or more years ago. The expected useful life of a flue gas desulfurization system is about 30 years or more.

**Figure 11.** Wet Scrubbing Process Diagram [10]

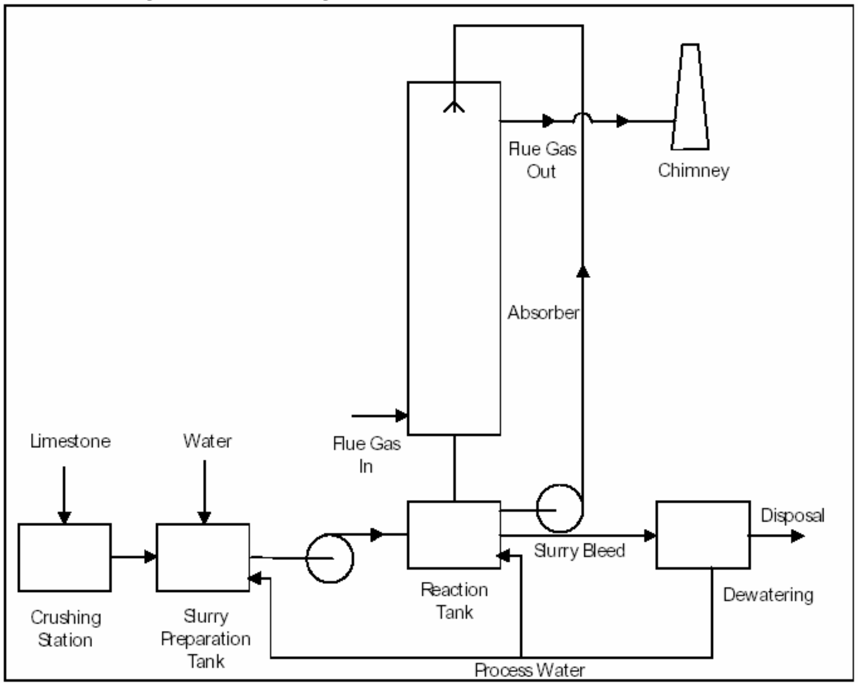



**Figure 12a.** A Wet FGD Absorber Vessel [7]

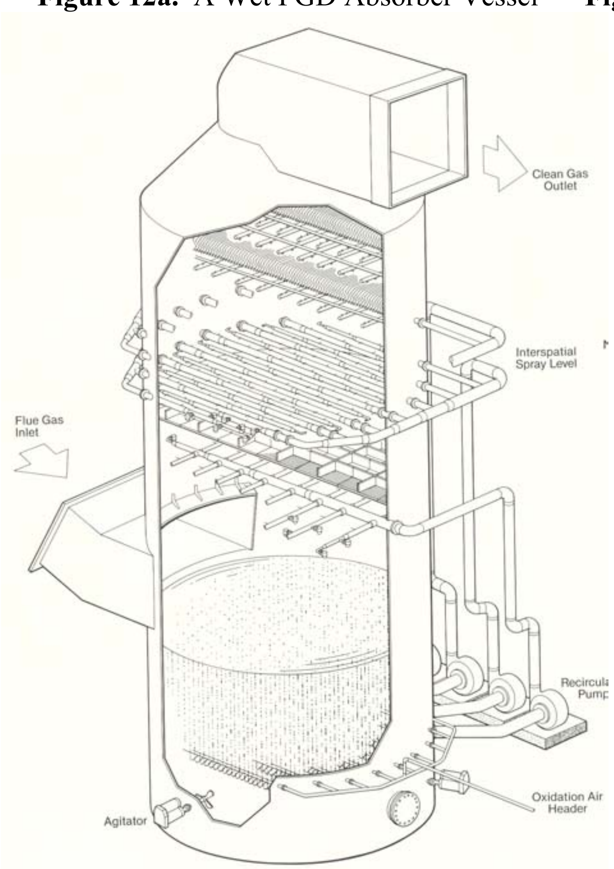
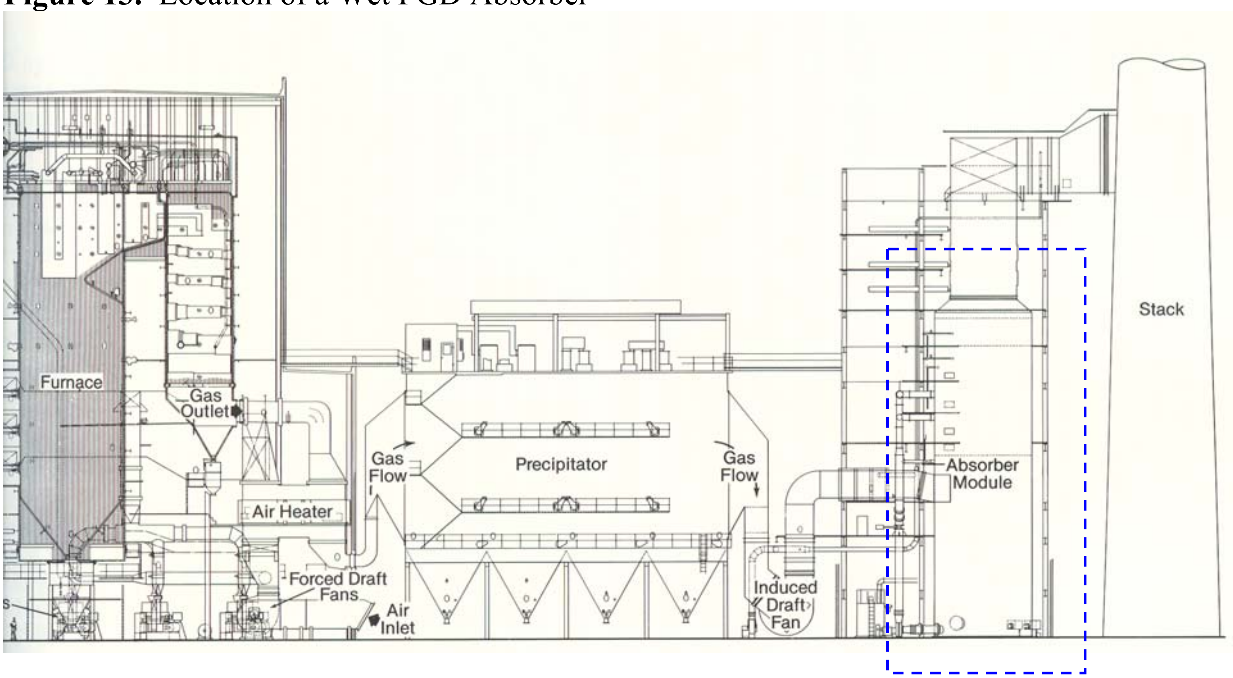



**Figure 12b**. Photo of a wet FGD Absorber Vessel [11]

Because an LSFO system operates at low temperatures it is usually the last pollution control device before the chimney, as in Figure 13. As Figure 13 shows, the LSFO absorber is usually located downstream of the PM control device (in this case an electrostatic precipitator) and immediately upstream of the stack. As a result, LSFO is frequently used to treat the exhaust gas of multiple boilers with the gases being emitted through a common stack. In fact, modern LSFO systems are capable of treating up to around 1000 MW equivalent of flue gas in a single absorber. As a result, it is possible for three 300 MW units to be served by a single LSFO system. Most of the equipment associated with an LSFO system can be built with the unit on line. However, ductwork connections with the boiler will require an outage of a month or so. Therefore, like SCR, this part of the retrofit is ideally scheduled at a time when the unit is shut down for other major work.

An operational advantage of an LSFO system is that having an LSFO system enables the plant to burn a wider range of fuels with much less concern for the impact on $SO_2$ emissions. TVA currently limits its $SO_2$ emissions at most of the TVA plants by limiting the sulfur content of the fuel at the plant, which restricts TVA's fuel options. With LSFO higher sulfur fuels can be burned. So, while LSFO systems incur cost to own and operate, they offer a benefit in fuel flexibility.

**Figure 13.** Location of a Wet FGD Absorber [7]



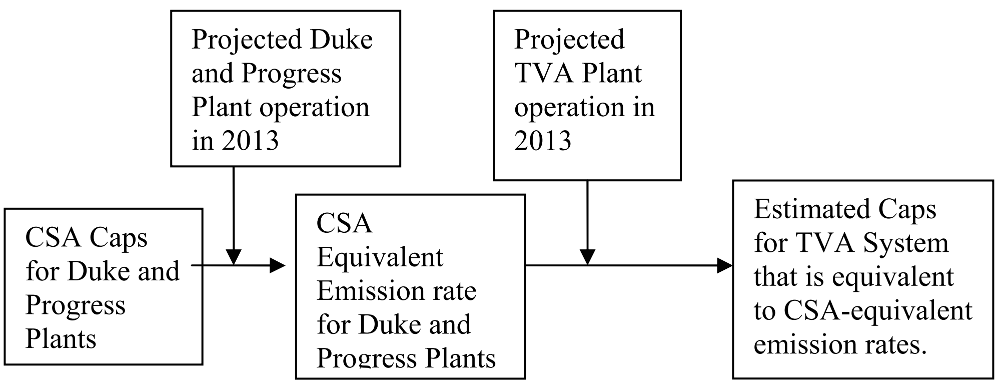

*Upgrades to existing LSFO systems*
TVA has some older LSFO systems, especially at Paradise units 1 and 2 and Widows Creek units 7 and 8. It may be possible to improve scrubber performance for these units. For example, if the two older scrubbers at Paradise can be upgraded to achieve higher removal efficiencies than they currently achieve (about 85% at Paradise 1&2 and about 90% at Cumberland, according to EIA 767 data), this might mitigate the need for scrubbers on smaller units, resulting in a lower cost for meeting an emissions cap similar to that of the CSA. Recent LSFO system upgrades at the Vectren Culley Station Units 2 & 3, E.On's Trimble County Unit 1, and

Michigan South Central Power's Endicott Station resulted in removal efficiencies in the range of 98% being achieved for each of these units. [12, 13, 14] However, Paradise units 1 & 2 might be limited to some degree by the fact that these units do not have dedicated PM control equipment, such as an ESP or FF. At Paradise 1 & 2 PM as well as $SO_2$ is removed in the scrubber.

**Estimate of CSA Equivalent Emissions Caps for TVA**

A first step in this analysis was to determine the level of emissions for the TVA system that is equivalent to the emissions limits required of plants located in North Carolina that are subject to the CSA. To this end it was necessary to examine the emission cap requirements of the CSA, estimate input or output -based limits equivalent to that cap and translate these into an emissions cap for TVA units that would be equivalent to the cap that the plants located in North Carolina subject to the CSA must abide by. The process is summarized in the flowchart of Figure 14. The CSA emission caps were translated into CSA-equivalent emission rates (input and output – based rates) based upon projected NC Plant operation in 2013. These emission rates were then translated to caps for the TVA system based upon projected operation of TVA plants in 2013.

**Figure 14**. Approach for estimating CSA-equivalent emission cap for TVA




CSA sets a combined limit of 130,000 tons/yr of $SO_2$ and 56,000 tons/yr of NOx on Duke and Progress coal-fired units in NC, as shown in Table 1, which shows the limits and their deadlines along with the historical 2000 emissions.

**Table 1**. Clean Smokestacks limits and historical emissions

| | | Clean Smokestacks Limits | | | |
|---|---|---|---|---|---|
| **NOx** | **2000** | **2007** | **2009** | **2013** | |
| **Progress** | 63,494 | 25,000 | 25,000 | 25,000 | tons/yr |
| **Duke** | 96,466 | 35,000 | 31,000 | 31,000 | tons/yr |
| | | | | | |
| **$SO_2$** | **2000** | **2007** | **2009** | **2013** | |
| **Progress** | 205,256 | None | 100,000 | 50,000 | tons/yr |
| **Duke** | 248,107 | None | 150,000 | 80,000 | tons/yr |
| | | | | | |
| | **2000** | **2007** | **2009** | **2013** | |
| **Total NOx** | 159,960 | 60,000 | 56,000 | 56,000 | tons/yr |
| **Total $SO_2$** | 453,363 | None | 250,000 | 130,000 | tons/yr |

This cap on the affected units makes it necessary to reduce total emissions between now and 2013 and continue to reduce emissions rates (measured in lb/MMBtu or lb/MWhr) as generation grows after 2013. EIA Form 767 data and EPA reported emissions and heat input data were used to determine recent generation and heat input levels for TVA and Progress and Duke NC coal-fired units. EPA's 2004 IPM results were used to estimate growth for NC's Progress and Duke coal-fired units as well as for TVA's coal-fired units.

Averaging the CSA-affected coal-fired units' EPA reported heat inputs for 2001 to 2004 arrives at an average heat input of 690 trillion Btu/yr. Averaging Duke and Progress MWhr for 2001-2004, results in 70,801,183 MWhr.

EPA's Integrated Planning Model (IPM) runs were used to make projections for 2013 operation of NC and TVA power plants. Using EPA's 2004 IPM runs (average of Base Case and CAIR-CAMR-CAVR modeling runs)[15] the projected 2015 heat input for Duke and Progress units in NC is 978 trillion Btu (Base Case) and 991 trillion Btu (CAIR-CAMR-CAVR). These IPM projections suggest an average growth rate in heat input of about 2.9%-3.0% annually to 2015. If the heat input and MWhr output grow in the same proportion over that period, this suggests that in 2013 the heat input and generation of these Progress and Duke units will be about 920 trillion Btu/yr and 94,231,100 MWhr, respectively. This growth rate, while high, can be accommodated with existing units. However, because IPM predicts new generating units but not expansion of existing generating plants, the IPM projections do not specifically include the effect of replacing Cliffside 1-4 (totaling 210 MW) with two 800 MW units, as Duke has recently announced its intentions to do. To address Cliffside, I adjusted the heat input and generation in NC in proportion to the increase in capacity (net increase of 590 MW for 12,496 MW or 4.7%) we arrive at 963 TBtu/yr and 98,659,962 MWhr. Using these estimated values for heat input and for MWhr of generation and the caps established under the CSA, the equivalent input and output based emissions rates can be determined and are shown in Table 2.

**Table 2.** Estimated Equivalent 2013 CSA Output/Input Based Emissions Rates

| | Output-based | Input based |
|---|---|---|
| **$SO_2$** | 2.76 lb/MWhr | 0.271 lb/MMBtu |
| **NOx** | 1.19 lb/MWhr | 0.117 lb/MMBtu |

Actual CSA equivalent rates for the state of NC are likely to be lower because additional coal generation is projected by IPM for NC that is not included in the calculations here. New coal generation that is predicted under the IPM models would have to comply with NSPS and would therefore lower the equivalent input and output based emissions rates if allowed to average in.

Averaging the TVA coal unit's EPA reported heat inputs for 2001 to 2004 arrives at an average heat input of 1,027,106,368 MMBtu/yr (1,027 trillion Btu/yr). Averaging TVA MWhr for 2001-2004 yields 94,657,064 MWhr. Using EPA's 2004 IPM runs (Base Case and CAIR-CAMR-CAVR modeling runs) the projected 2015 heat input to TVA's coal units is 1156 trillion Btu (Base Case) and 1085 trillion Btu (CAIR-CAMR-CAVR). These IPM projections suggest an average growth rate in heat input of between 0.46% and 1.0% annually to 2015. If the heat input and MWhr output grow in the same proportion over that period at an assumed growth rate of 0.7%/yr, this suggests that in 2013 the heat input and generation of TVA units will be about

1,101 trillion Btu/yr and 101,495,721 MWhr, respectively. Using these estimates for 2013 inputs and the CSA-equivalent input and output based emission rates shown in Table 2, the system-wide limits of Table 3 are determined. The reason that the Input-Based and Output-Based limits are not the same for TVA are because, using EPA's reported heat input and the EIA Form 767 generation data for 2001 through 2004, TVA's units apparently report a higher heat input per unit of electricity output than CSA-affected Duke and Progress units in North Carolina. As a result, the output-based limit of Table 3 is slightly lower than the input-based limit. An output-based limit more accurately reflects the tradeoff between the cost of pollutant emissions and the benefit of electric power generated.

**Table 3.** Input and Output Based Emission Levels that are Equivalent to Table 2 CSA-equivalent Input and Output Based Emission Rates

| **TVA's Estimated Input or Output Level** | **Output-Based System-Wide Emissions Limit (tons)** | | **Input-Based System-Wide Emissions Limit (tons)** | |
|---|---|---|---|---|
| | **NOx** | **$SO_2$** | **NOx** | **$SO_2$** |
| 1,101 trillion Btu/yr | | | 64,426 | 149,226 |
| 101.5 million MWhr | 60,390 | 140,064 | | |

**Estimate of Emissions**

Estimates of 2013 emissions from TVA plants were made under two scenarios that entailed retrofit of existing plants:

1. Base Case: Projected 2013 emissions for TVA units as currently equipped with Paradise 3 having a scrubber installed that controls to 0.60 lb/MMBtu (similar to the other Paradise units) and with currently installed SCRs operating on an annual basis due to anticipated Federal CAIR requirements.
2. CSA Equivalent: Projected 2013 emissions for TVA units as currently equipped with Paradise 3 having a scrubber installed that controls to 0.60 lb/MMBtu and additional scrubbers and NOx controls added to achieve near the CSA Output Based Emission Rates. New scrubbers (except Paradise) control to 0.15 lb/MMBtu.

Since the Paradise units are large units, the impact of the emission rate can be large. Modern wet FGD systems typically provide emissions rates at or below 0.15 lb/MMBtu, which is much better than the performance of the Paradise 1 & 2 FGD systems, or the expected performance for the Paradise 3 FGD system (based on NEEDS database). However, in TVA's Response to Interrogatory No. 8, it shows that the Paradise 3 FGD is designed for 98%. So, it should be possible to achieve much lower emissions rates than 0.60 lb/MMBtu. For example, the scrubbers at Duke Power to be in operation by 2013 are all expected to provide 0.15 lb/MMBtu or lower (in the case of new proposed units at Cliffside, 0.08 lb/MMBtu). If the Paradise 3 FGD does operate at an emissions rate closer to 0.15 lb/MMBtu, this would reduce the emissions of the Base Case somewhat. However, it would also reduce the number of additional FGD systems that are necessary to achieve the CSA-equivalent caps.

Unit-by-unit emissions projections were developed from these assumptions. This was done by taking the average 2001-2004 heat input for each unit, growing it at 0.7% annually (consistent with EPA's IPM projections) and making assumptions about the emissions rate based upon a projected air pollution control configuration. The summary of the results are shown in Table 4 and details of these results are shown in Tables 5 and 6.

**Table 4.** Summary of 2005 and Projected 2013 TVA Emissions

| | NOx (CSA target 1.19 lb/MWhr) | | SO2 (CSA target 2.76 lb/MWhr) | |
|---|---|---|---|---|
| | lb/MWhr | Tpy | lb/MWhr | Tpy |
| 2005 Actual | 3.93* | 191,033 | 9.52* | 462,180 |
| 2013 Base Case | 2.27** | 115,144** | 8.85 | 448,916 |
| 2013 CSA equivalent | 1.17 | 59,515 | 2.70 | 137,015 |

** 2005 MWhr estimated from 2005 EPA reported heat input, 2004 EIA 767 reported MWhr and 2004 EPA reported heat input, assuming that MWhr output is proportional to heat input*
*** Assumes annual operation of post-combustion controls that currently are operated on a seasonal basis*

Comparing the 2013 Base Case to TVA's 2005 annual emissions, some emissions reductions are achieved in the 2013 Base Case. These reductions are achieved through the addition of the Paradise 3 FGD and also through the assumption that in 2013 TVA will operate its SCRs on an annual basis (rather than seasonally as is TVA's current practice) due to US EPA's Clean Air Interstate Rule (CAIR). CAIR does not *require* TVA to operate their SCRs annually because CAIR permits allowance trading. So, actual emissions might exceed the 2013 Base Case emissions estimate. However, it is reasonable to expect TVA to operate these SCRs since they are already installed and the incremental control cost is likely to be less than the market value of NOx allowances that are generated from operating the SCR systems.

The TVA units are capable of meeting the CSA equivalent target for NOx emissions by installing SCRs on all units except Johnsonville 1-10 and Shawnee 1-5 and Shawnee 10. At Johnsonville 1-10 and Shawnee 1-5, SNCR is assumed to be installed to achieve the CSA equivalent NOx emissions. These units were selected for SNCR because they are smaller units, which are likely to be well suited for SNCR rather than SCR. No changes are assumed to be made to Shawnee 10. With regard to $SO_2$ emissions, the TVA total $SO_2$ emissions are projected to be under the CSA output-based target of 2.76 lb/MWhr with all units but Shawnee 10 (a CFB) scrubbed.

The TVA units are capable of meeting the CSA equivalent target for $SO_2$ emissions by installing FGD on all units except Shawnee 10. Shawnee 1-10 might be candidates for dry scrubbers due to the fabric filters on these units. But, LSFO was assumed because of the common stack arrangement for units 1-5 and 6-10 that may make LSFO more attractive than an SDA upstream of the existing fabric filters. In the estimate of emissions, I assumed LSFO was not installed on Shawnee 10 because it is a CFB. However, due to the common stack for Shawnee 6-10, it might make sense to have Shawnee 10 exhaust gas combined into the LSFO along with the exhaust gas from Shawnee 6-9.

If the performance of the existing Paradise and Widows Creek scrubbers can be improved to reduce their emissions, then compliance with the CSA $SO_2$ target will be easier. These units are large and have older scrubbers that operate at lower removal efficiencies than state-of-the-art scrubbers. As described above, improvements at other facilities suggest that improvements may be possible on TVA's older FGD systems, such as Paradise 1 & 2 and possibly at Widow's Creek 7 & 8. If improvements were made to the Paradise or Widows Creek scrubbers, this would substantially reduce $SO_2$ emissions and reduce the need for FGD systems at other units in order to meet the CSA equivalent emissions cap. For example, if Widow's Creek 7 & 8 and all of the Paradise FGD systems controlled to 0.15 lb/MMBtu, then scrubbers could potentially be avoided at Johnsonville 6-10 and Gallatin 1 & 2 while achieving emissions under the CSA-equivalent caps that have been estimated.

In selecting a control strategy to meet the CSA equivalent emissions target, a control strategy was selected that was expected to achieve at or below the target emissions rate. This was done by evaluating what would happen if control technology were installed on existing units. There are other ways that TVA might choose to meet the CSA equivalent NOx and $SO_2$ emissions targets, and TVA might choose another approach depending upon their plans for the plants or other considerations. As previously discussed, it may be possible to improve the removal efficiency of some of the existing FGD systems. This would be especially helpful on large units such as Paradise because this could help reduce the need for more FGD systems. TVA could also increase its use of low sulfur PRB coal, which might also reduce the need for scrubbers somewhat. Another example of an alternative approach would be repowering some of the older TVA plants with newer, more efficient units equipped with state-of-the-art emission controls, as Duke is proposing to do at Cliffside. Such approaches might be more economically attractive to TVA than what is shown here and could possibly achieve the same or better emissions levels at a lower cost. Another approach is to shift generation away from older plants in favor of generating sources that are less polluting, such as nuclear or renewables. It may also be possible to mitigate emissions somewhat through demand-side management measures. However, these other choices involve broader business decisions that are not examined here and may be considered by others.

More widespread use of SCR and FGD will reduce mercury emissions as well. When FGD is added to a bituminous coal-fired boiler equipped with a cold-side ESP, cobenefit removal is expected to increase from around 30% (ESP only) to around 60-70% (combined removal from ESP & FGD). If SCR is installed upstream of the cold side ESP and FGD system, the total cobenefit removal will increase further to about 90%. Thus, cobenefit removal of mercury can increase substantially when NOx and $SO_2$ controls are added to a boiler. With a fabric filter, such as at Shawnee, about 90% mercury removal may occur. Based upon estimates using these assumed capture rates and an annual growth in heat input of 0.7%, and the 2005 Estimated Hg emissions from TVA's Response to Interrogatory No. 5, the 2013 CSA-Equivalent case is expected to result in about 54% reduction in overall mercury emissions as compared to the Base Case projected 2013 emissions. Table 7 shows the details of this analysis.

**Table 5.** Base Case Projected 2013 Emissions

| Plant | # | Base Case | | | | | |
|---|---|---|---|---|---|---|---|
| | | NOx | | | SO2 | | |
| | | Tech | Lb/MMBtu | TPY | Tech | Lb/MMBtu | TPY |
| Allen Steam Plant | 1 | SCR | 0.07 | 657 | Low Sulfur | 0.91 | 8,227 |
| Allen Steam Plant | 2 | SCR | 0.09 | 795 | Low Sulfur | 0.95 | 8,850 |
| Allen Steam Plant | 3 | SCR | 0.09 | 781 | Low Sulfur | 0.89 | 7,843 |
| Bull Run | 1 | SCR | 0.08 | 2,295 | Low Sulfur | 1.17 | 33,851 |
| Colbert | 1 | LNB | 0.44 | 2,828 | Blend | 0.89 | 5,777 |
| Colbert | 2 | LNB | 0.44 | 3,002 | Blend | 0.89 | 6,134 |
| Colbert | 3 | LNB | 0.44 | 2,795 | Blend | 0.89 | 5,710 |
| Colbert | 4 | LNB | 0.44 | 2,617 | Blend | 0.89 | 5,347 |
| Colbert | 5 | SCR | 0.05 | 729 | Blend | 0.91 | 12,833 |
| Cumberland | 1 | SCR | 0.07 | 2,912 | FGD | 0.20 | 8,075 |
| Cumberland | 2 | SCR | 0.07 | 3,959 | FGD | 0.23 | 12,321 |
| Gallatin | 1 | LNB | 0.25 | 2,291 | Blend | 0.71 | 6,420 |
| Gallatin | 2 | LNB | 0.25 | 2,321 | Blend | 0.71 | 6,504 |
| Gallatin | 3 | LNB | 0.31 | 3,098 | Blend | 0.71 | 7,076 |
| Gallatin | 4 | LNB | 0.31 | 3,234 | Blend | 0.71 | 7,386 |
| John Sevier | 1 | LNB | 0.41 | 2,790 | Low Sulfur | 1.25 | 8,513 |
| John Sevier | 2 | LNB | 0.41 | 2,803 | Low Sulfur | 1.25 | 8,552 |
| John Sevier | 3 | LNB | 0.43 | 3,071 | Low Sulfur | 1.23 | 8,882 |
| John Sevier | 4 | LNB | 0.43 | 2,839 | Low Sulfur | 1.23 | 8,211 |
| Johnsonville | 1 | OPT | 0.50 | 2,344 | Blend | 1.81 | 8,411 |
| Johnsonville | 2 | OPT | 0.50 | 2,305 | Blend | 1.81 | 8,274 |
| Johnsonville | 3 | OPT | 0.50 | 2,223 | Blend | 1.81 | 7,980 |
| Johnsonville | 4 | OPT | 0.50 | 2,283 | Blend | 1.81 | 8,195 |
| Johnsonville | 5 | OPT | 0.50 | 2,077 | Blend | 1.81 | 7,454 |
| Johnsonville | 6 | OPT | 0.50 | 2,150 | Blend | 1.81 | 7,717 |
| Johnsonville | 7 | LNB | 0.50 | 2,406 | Blend | 1.81 | 8,634 |
| Johnsonville | 8 | LNB | 0.50 | 2,488 | Blend | 1.81 | 8,930 |
| Johnsonville | 9 | LNB | 0.50 | 2,403 | Blend | 1.81 | 8,623 |
| Johnsonville | 10 | LNB | 0.50 | 2,219 | Blend | 1.81 | 7,963 |
| Kingston | 1 | SCR | 0.06 | 323 | Low Sulfur | 1.12 | 5,917 |
| Kingston | 2 | SCR | 0.06 | 320 | Low Sulfur | 1.12 | 5,849 |
| Kingston | 3 | SCR | 0.06 | 335 | Low Sulfur | 1.12 | 6,124 |
| Kingston | 4 | SCR | 0.06 | 326 | Low Sulfur | 1.12 | 5,964 |
| Kingston | 5 | SCR | 0.06 | 416 | Low Sulfur | 1.12 | 7,608 |
| Kingston | 6 | SCR | 0.05 | 365 | Low Sulfur | 1.12 | 8,141 |
| Kingston | 7 | SCR | 0.05 | 347 | Low Sulfur | 1.12 | 7,734 |
| Kingston | 8 | SCR | 0.05 | 349 | Low Sulfur | 1.12 | 7,794 |
| Kingston | 9 | SCR | 0.05 | 337 | Low Sulfur | 1.12 | 7,528 |
| Paradise | 1 | SCR | 0.10 | 2,456 | FGD | 0.63 | 15,124 |
| Paradise | 2 | SCR | 0.11 | 2,721 | FGD | 0.65 | 16,545 |
| Paradise | 3 | SCR | 0.11 | 3,228 | FGD | 0.60 | 18,447 |
| Shawnee | 1 | LNB | 0.36 | 2,031 | Blend | 0.77 | 4,297 |
| Shawnee | 2 | LNB | 0.36 | 1,993 | Blend | 0.77 | 4,219 |
| Shawnee | 3 | LNB | 0.36 | 2,107 | Blend | 0.77 | 4,459 |
| Shawnee | 4 | LNB | 0.36 | 1,967 | Blend | 0.77 | 4,163 |
| Shawnee | 5 | LNB | 0.36 | 1,932 | Blend | 0.77 | 4,089 |
| Shawnee | 6 | LNB | 0.40 | 2,169 | Blend | 0.77 | 4,196 |
| Shawnee | 7 | LNB | 0.40 | 2,397 | Blend | 0.77 | 4,636 |
| Shawnee | 8 | LNB | 0.40 | 2,369 | Blend | 0.77 | 4,583 |
| Shawnee | 9 | LNB | 0.40 | 2,267 | Blend | 0.77 | 4,342 |
| Shawnee | 10 | CFB | 0.33 | 1,586 | CFB | 0.45 | 2,163 |
| Widows Creek | 1 | OPT | 0.50 | 1,894 | Blend | 0.92 | 3,507 |
| Widows Creek | 2 | OPT | 0.50 | 2,022 | Blend | 0.92 | 3,744 |
| Widows Creek | 3 | OPT | 0.50 | 2,205 | Blend | 0.92 | 4,082 |
| Widows Creek | 4 | OPT | 0.50 | 2,004 | Blend | 0.92 | 3,711 |
| Widows Creek | 5 | OPT | 0.50 | 2,128 | Blend | 0.92 | 3,940 |
| Widows Creek | 6 | OPT | 0.50 | 2,083 | Blend | 0.92 | 3,856 |
| Widows Creek | 7 | SCR | 0.06 | 892 | FGD | 0.56 | 8,950 |
| Widows Creek | 8 | SCR | 0.06 | 860 | FGD | 0.30 | 4,508 |
| **Total** | | | | **115,144** | | | **448,916** |

**Table 6.** CSA Equivalent Projected 2013 Emissions

| | | CSA Equivalent | | | | | |
|---|---|---|---|---|---|---|---|
| | | NOx | | | SO2 | | |
| Plant | # | Tech | Lb/MMBtu | TPY | Tech | Lb/MMBtu | TPY |
| Allen Steam Plant | 1 | SCR | 0.07 | 657 | FGD | 0.15 | 1,350 |
| Allen Steam Plant | 2 | SCR | 0.09 | 795 | FGD | 0.15 | 1,403 |
| Allen Steam Plant | 3 | SCR | 0.09 | 781 | FGD | 0.15 | 1,316 |
| Bull Run | 1 | SCR | 0.08 | 2,295 | FGD | 0.15 | 4,341 |
| Colbert | 1 | SCR | 0.06 | 403 | FGD | 0.15 | 968 |
| Colbert | 2 | SCR | 0.06 | 428 | FGD | 0.15 | 1,028 |
| Colbert | 3 | SCR | 0.06 | 398 | FGD | 0.15 | 957 |
| Colbert | 4 | SCR | 0.06 | 373 | FGD | 0.15 | 896 |
| Colbert | 5 | SCR | 0.05 | 729 | FGD | 0.15 | 2,104 |
| Cumberland | 1 | SCR | 0.07 | 2,912 | FGD | 0.20 | 8,075 |
| Cumberland | 2 | SCR | 0.07 | 3,959 | FGD | 0.23 | 12,321 |
| Gallatin | 1 | SCR | 0.05 | 454 | FGD | 0.15 | 1,363 |
| Gallatin | 2 | SCR | 0.05 | 460 | FGD | 0.15 | 1,381 |
| Gallatin | 3 | SCR | 0.05 | 498 | FGD | 0.15 | 1,494 |
| Gallatin | 4 | SCR | 0.05 | 520 | FGD | 0.15 | 1,560 |
| John Sevier | 1 | SCR | 0.05 | 372 | FGD | 0.15 | 1,023 |
| John Sevier | 2 | SCR | 0.05 | 374 | FGD | 0.15 | 1,028 |
| John Sevier | 3 | SCR | 0.05 | 389 | FGD | 0.15 | 1,081 |
| John Sevier | 4 | SCR | 0.05 | 360 | FGD | 0.15 | 1,000 |
| Johnsonville | 1 | SNCR | 0.38 | 1,758 | FGD | 0.15 | 699 |
| Johnsonville | 2 | SNCR | 0.38 | 1,729 | FGD | 0.15 | 687 |
| Johnsonville | 3 | SNCR | 0.38 | 1,668 | FGD | 0.15 | 663 |
| Johnsonville | 4 | SNCR | 0.38 | 1,713 | FGD | 0.15 | 681 |
| Johnsonville | 5 | SNCR | 0.38 | 1,558 | FGD | 0.15 | 619 |
| Johnsonville | 6 | SNCR | 0.38 | 1,613 | FGD | 0.15 | 641 |
| Johnsonville | 7 | SNCR | 0.38 | 1,804 | FGD | 0.15 | 717 |
| Johnsonville | 8 | SNCR | 0.38 | 1,866 | FGD | 0.15 | 742 |
| Johnsonville | 9 | SNCR | 0.38 | 1,802 | FGD | 0.15 | 716 |
| Johnsonville | 10 | SNCR | 0.38 | 1,664 | FGD | 0.15 | 662 |
| Kingston | 1 | SCR | 0.06 | 323 | FGD | 0.15 | 794 |
| Kingston | 2 | SCR | 0.06 | 320 | FGD | 0.15 | 785 |
| Kingston | 3 | SCR | 0.06 | 335 | FGD | 0.15 | 822 |
| Kingston | 4 | SCR | 0.06 | 326 | FGD | 0.15 | 800 |
| Kingston | 5 | SCR | 0.06 | 416 | FGD | 0.15 | 1,021 |
| Kingston | 6 | SCR | 0.05 | 365 | FGD | 0.15 | 1,095 |
| Kingston | 7 | SCR | 0.05 | 347 | FGD | 0.15 | 1,040 |
| Kingston | 8 | SCR | 0.05 | 349 | FGD | 0.15 | 1,048 |
| Kingston | 9 | SCR | 0.05 | 337 | FGD | 0.15 | 1,012 |
| Paradise | 1 | SCR | 0.10 | 2,456 | FGD | 0.63 | 15,124 |
| Paradise | 2 | SCR | 0.11 | 2,721 | FGD | 0.65 | 16,545 |
| Paradise | 3 | SCR | 0.11 | 3,228 | FGD | 0.60 | 18,447 |
| Shawnee | 1 | SNCR | 0.27 | 1,523 | FGD | 0.15 | 841 |
| Shawnee | 2 | SNCR | 0.27 | 1,495 | FGD | 0.15 | 826 |
| Shawnee | 3 | SNCR | 0.27 | 1,580 | FGD | 0.15 | 873 |
| Shawnee | 4 | SNCR | 0.27 | 1,475 | FGD | 0.15 | 815 |
| Shawnee | 5 | SNCR | 0.27 | 1,449 | FGD | 0.15 | 801 |
| Shawnee | 6 | SCR | 0.05 | 282 | FGD | 0.15 | 821 |
| Shawnee | 7 | SCR | 0.05 | 312 | FGD | 0.15 | 908 |
| Shawnee | 8 | SCR | 0.05 | 308 | FGD | 0.15 | 897 |
| Shawnee | 9 | SCR | 0.05 | 295 | FGD | 0.15 | 850 |
| Shawnee | 10 | CFB | 0.33 | 1,586 | CFB | 0.45 | 2,163 |
| Widows Creek | 1 | SCR | 0.06 | 246 | FGD | 0.15 | 569 |
| Widows Creek | 2 | SCR | 0.06 | 263 | FGD | 0.15 | 608 |
| Widows Creek | 3 | SCR | 0.06 | 287 | FGD | 0.15 | 663 |
| Widows Creek | 4 | SCR | 0.06 | 261 | FGD | 0.15 | 602 |
| Widows Creek | 5 | SCR | 0.06 | 277 | FGD | 0.15 | 640 |
| Widows Creek | 6 | SCR | 0.06 | 271 | FGD | 0.15 | 626 |
| Widows Creek | 7 | SCR | 0.06 | 892 | FGD | 0.56 | 8,950 |
| Widows Creek | 8 | SCR | 0.06 | 860 | FGD | 0.30 | 4,508 |
| Total | | | | 59,515 | | | 137,015 |

**Table 7.** Estimates of Hg Emissions

| Plant | | 2005 Estimated Hg by TVA | | Estimated 2013 Base Case | | Estimate 2013 with CSA controls | | |
|---|---|---|---|---|---|---|---|---|
| | | Ton/yr | lb/yr | Ton/yr | lb/yr | Ton/yr | lb/yr | % Red'n |
| Allen Steam Plant | 1 | 0.03080 | 61.6 | 0.0326 | 65.1 | 0.0047 | 9.3 | 85.7% |
| Allen Steam Plant | 2 | 0.02980 | 59.6 | 0.0315 | 63.0 | 0.0045 | 9.0 | 85.7% |
| Allen Steam Plant | 3 | 0.03160 | 63.2 | 0.0334 | 66.8 | 0.0048 | 9.5 | 85.7% |
| Bull Run | 1 | 0.01280 | 25.6 | 0.0135 | 27.1 | 0.0019 | 3.9 | 85.7% |
| Colbert | 1 | 0.01670 | 33.4 | 0.0177 | 35.3 | 0.0025 | 5.0 | 85.7% |
| Colbert | 2 | 0.01630 | 32.6 | 0.0172 | 34.5 | 0.0025 | 4.9 | 85.7% |
| Colbert | 3 | 0.01860 | 37.2 | 0.0197 | 39.3 | 0.0028 | 5.6 | 85.7% |
| Colbert | 4 | 0.01860 | 37.2 | 0.0197 | 39.3 | 0.0028 | 5.6 | 85.7% |
| Colbert | 5 | 0.04120 | 82.4 | 0.0436 | 87.1 | 0.0062 | 12.4 | 85.7% |
| Cumberland | 1 | 0.06210 | 124.2 | 0.0657 | 131.3 | 0.0657 | 131.3 | 0.0% |
| Cumberland | 2 | 0.06020 | 120.4 | 0.0637 | 127.3 | 0.0637 | 127.3 | 0.0% |
| Gallatin | 1 | 0.03400 | 68.0 | 0.0360 | 71.9 | 0.0051 | 10.3 | 85.7% |
| Gallatin | 2 | 0.03250 | 65.0 | 0.0344 | 68.7 | 0.0049 | 9.8 | 85.7% |
| Gallatin | 3 | 0.03750 | 75.0 | 0.0397 | 79.3 | 0.0057 | 11.3 | 85.7% |
| Gallatin | 4 | 0.03820 | 76.4 | 0.0404 | 80.8 | 0.0058 | 11.5 | 85.7% |
| John Sevier | 1 | 0.03860 | 77.2 | 0.0408 | 81.6 | 0.0058 | 11.7 | 85.7% |
| John Sevier | 2 | 0.04040 | 80.8 | 0.0427 | 85.4 | 0.0061 | 12.2 | 85.7% |
| John Sevier | 3 | 0.03680 | 73.6 | 0.0389 | 77.8 | 0.0056 | 11.1 | 85.7% |
| John Sevier | 4 | 0.04050 | 81.0 | 0.0428 | 85.6 | 0.0061 | 12.2 | 85.7% |
| Johnsonville | 1 | 0.01400 | 28.0 | 0.0148 | 29.6 | 0.0085 | 16.9 | 42.9% |
| Johnsonville | 2 | 0.01480 | 29.6 | 0.0156 | 31.3 | 0.0089 | 17.9 | 42.9% |
| Johnsonville | 3 | 0.01530 | 30.6 | 0.0162 | 32.4 | 0.0092 | 18.5 | 42.9% |
| Johnsonville | 4 | 0.01520 | 30.4 | 0.0161 | 32.1 | 0.0092 | 18.4 | 42.9% |
| Johnsonville | 5 | 0.01220 | 24.4 | 0.0129 | 25.8 | 0.0074 | 14.7 | 42.9% |
| Johnsonville | 6 | 0.01370 | 27.4 | 0.0145 | 29.0 | 0.0083 | 16.6 | 42.9% |
| Johnsonville | 7 | 0.01370 | 27.4 | 0.0145 | 29.0 | 0.0083 | 16.6 | 42.9% |
| Johnsonville | 8 | 0.01540 | 30.8 | 0.0163 | 32.6 | 0.0093 | 18.6 | 42.9% |
| Johnsonville | 9 | 0.01580 | 31.6 | 0.0167 | 33.4 | 0.0095 | 19.1 | 42.9% |
| Johnsonville | 10 | 0.01540 | 30.8 | 0.0163 | 32.6 | 0.0093 | 18.6 | 42.9% |
| Kingston | 1 | 0.02170 | 43.4 | 0.0229 | 45.9 | 0.0033 | 6.6 | 85.7% |
| Kingston | 2 | 0.02130 | 42.6 | 0.0225 | 45.0 | 0.0032 | 6.4 | 85.7% |
| Kingston | 3 | 0.01930 | 38.6 | 0.0204 | 40.8 | 0.0029 | 5.8 | 85.7% |
| Kingston | 4 | 0.02150 | 43.0 | 0.0227 | 45.5 | 0.0032 | 6.5 | 85.7% |
| Kingston | 5 | 0.02520 | 50.4 | 0.0266 | 53.3 | 0.0038 | 7.6 | 85.7% |
| Kingston | 6 | 0.02430 | 48.6 | 0.0257 | 51.4 | 0.0037 | 7.3 | 85.7% |
| Kingston | 7 | 0.02930 | 58.6 | 0.0310 | 62.0 | 0.0044 | 8.9 | 85.7% |
| Kingston | 8 | 0.02880 | 57.6 | 0.0305 | 60.9 | 0.0044 | 8.7 | 85.7% |
| Kingston | 9 | 0.02600 | 52.0 | 0.0275 | 55.0 | 0.0039 | 7.9 | 85.7% |
| Paradise | 1 | 0.06400 | 128.0 | 0.0677 | 135.3 | 0.0677 | 135.3 | 0.0% |
| Paradise | 2 | 0.07250 | 145.0 | 0.0767 | 153.3 | 0.0767 | 153.3 | 0.0% |
| Paradise | 3 | 0.10700 | 214.0 | 0.0162 | 32.3 | 0.0162 | 32.3 | 0.0% |
| Shawnee | 1 | 0.00942 | 18.8 | 0.0100 | 19.9 | 0.0100 | 19.9 | 0.0% |
| Shawnee | 2 | 0.00947 | 18.9 | 0.0100 | 20.0 | 0.0100 | 20.0 | 0.0% |
| Shawnee | 3 | 0.00917 | 18.3 | 0.0097 | 19.4 | 0.0097 | 19.4 | 0.0% |
| Shawnee | 4 | 0.01040 | 20.8 | 0.0110 | 22.0 | 0.0110 | 22.0 | 0.0% |
| Shawnee | 5 | 0.01060 | 21.2 | 0.0112 | 22.4 | 0.0112 | 22.4 | 0.0% |
| Shawnee | 6 | 0.01030 | 20.6 | 0.0109 | 21.8 | 0.0109 | 21.8 | 0.0% |
| Shawnee | 7 | 0.00908 | 18.2 | 0.0096 | 19.2 | 0.0096 | 19.2 | 0.0% |
| Shawnee | 8 | 0.00998 | 20.0 | 0.0106 | 21.1 | 0.0106 | 21.1 | 0.0% |
| Shawnee | 9 | 0.01030 | 20.6 | 0.0109 | 21.8 | 0.0109 | 21.8 | 0.0% |
| Shawnee | 10 | 0.00116 | 2.3 | 0.0012 | 2.5 | 0.0012 | 2.5 | 0.0% |
| Widows Creek | 1 | 0.01200 | 24.0 | 0.0127 | 25.4 | 0.0018 | 3.6 | 85.7% |
| Widows Creek | 2 | 0.01160 | 23.2 | 0.0123 | 24.5 | 0.0018 | 3.5 | 85.7% |
| Widows Creek | 3 | 0.01090 | 21.8 | 0.0115 | 23.1 | 0.0016 | 3.3 | 85.7% |
| Widows Creek | 4 | 0.01230 | 24.6 | 0.0130 | 26.0 | 0.0019 | 3.7 | 85.7% |
| Widows Creek | 5 | 0.01090 | 21.8 | 0.0115 | 23.1 | 0.0016 | 3.3 | 85.7% |
| Widows Creek | 6 | 0.01120 | 22.4 | 0.0118 | 23.7 | 0.0017 | 3.4 | 85.7% |
| Widows Creek | 7 | 0.01730 | 34.6 | 0.0183 | 36.6 | 0.0183 | 36.6 | 0.0% |
| Widows Creek | 8 | 0.05130 | 102.6 | 0.0542 | 108.5 | 0.0542 | 108.5 | 0.0% |
| **Total** | | **1.471** | **2,942** | **1.4584** | **2,917** | **0.6663** | **1,333** | **54.3%** |

## The Cost of Controlling NOx and $SO_2$ to CSA Equivalent Levels

Approximate costs for installing and operating these additional emissions controls were made assuming that TVA pursued a control-technology approach as described in the previous section. Actual costs realized will differ from this estimate based upon site-specific factors that determine the difficulty of the retrofits, market pricing of material and labor, and other factors. For the purpose of developing a budget for constructing this equipment, a more detailed engineering study would be necessary. The approach for estimating the cost was to use algorithms developed for and used by the US EPA in its cost estimating for the Integrated Planning Model (IPM) and using US EPA's Coal Utility Environmental Cost (CUECost) model. These were further adjusted using published industry escalation factors to account for capital cost escalation.

$SO_2$ control capital cost algorithms from a study recently completed by Andover Technology Partners for the US EPA are integrated into US EPA's CUECost and Integrated Planning Model. Operating cost was estimated using EPA's CUECost program. These algorithms are described in References 16 and 17. Using EPA's CUECost, the cost curves of Figures 10 and 11 were developed for LSFO FGD systems retrofit on boilers firing a high sulfur bituminous coal (3.43% sulfur and 11,922 Btu/lb). Although some of the TVA units currently burn low-medium sulfur coal, it is assumed that with LSFO installed they will likely use a higher sulfur coal. The fixed O&M costs are realized annually while the capital costs are one-time costs and are typically financed and amortized over a period of years. Figures 15 and 16 plot normalized capital cost (in $/MW) and normalized Fixed Operating Cost (FOM, in $/MW of capacity per year), respectively. As shown, there are economies of scale for FGD systems on larger boilers, or equivalently, larger gas flows. So, there is a capital cost and FOM cost benefit in combining the gas flows of several boilers into one FGD system so long as a maximum allowable FGD absorber size (in the range of about 1,000 MW) is not exceeded. In estimating the cost of FGD, it was assumed that units with common stacks would have their exhaust gas combined to a single absorber, providing that the combined exhaust gases were the equivalent of 1000 MW or less in capacity. To bring the capital costs from 1999 to 2006 dollars, I also used the Vatavuk Air Pollution Control Cost Index for Wet Scrubbers that is published in Chemical Engineering magazine.[18, 19] In addition to these costs are variable operating costs (VOM) that I estimated at about $1.87/MWhr or about $0.17/MMBtu.

For the capital and fixed operating cost of SCR, algorithms included in US EPA's IPM Model and recently incorporated into US EPA's CUECost were used along with the Vatavuk cost indices discussed earlier.[17, 18, 19] Variable Operating Cost of the SCR was estimated based on estimated unit uncontrolled emissions (determined by reported uncontrolled emissions) and the higher uncontrolled rate of 87% reduction or outlet emission rate of 0.05 lb/MMBtu (as opposed to a generic assumption for emissions, as used in IPM models), ammonia cost at $400/ton, catalyst cost at $5000/MW (with 1/3rd of the catalyst replaced every 3 years) and parasitic power of 0.5% of output valued at $25/MWhr. SCR fixed O&M was 0.66% of capital cost. For SNCR, capital cost was assumed to be $18/KW, fixed O&M equal to $0.30/MW, and variable O&M based on a Normalized Stoichiometric Ratio (NSR, a measure of chemical treatment rate) of 1.0 and urea cost of $300/ton.

**Figure 15.** Normalized LSFO Capital Cost 1999 dollars

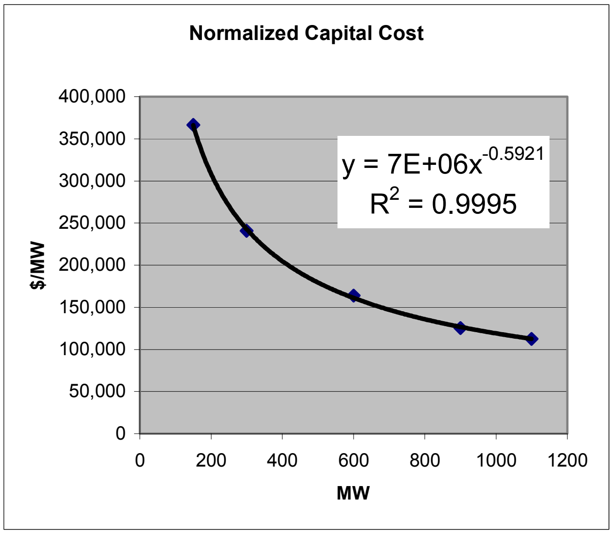
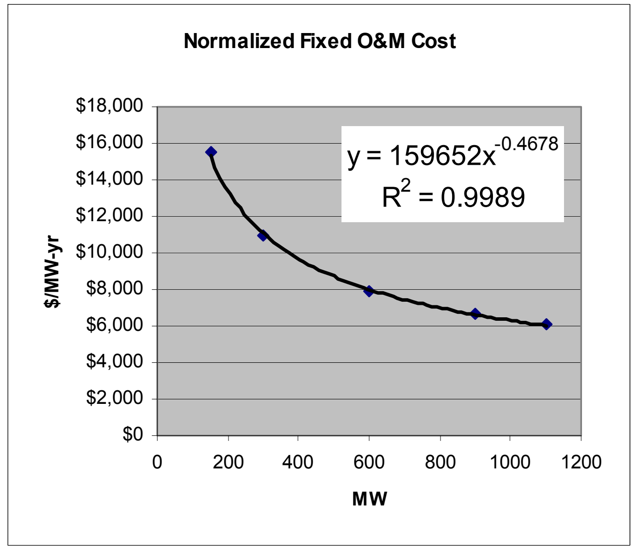



**Figure 16**. Normalized LSFO Fixed O&M




Using this approach, estimates of the capital and operating costs of complying with a CSA-equivalent emissions cap for NOx and $SO_2$ are shown in Table 8. It is important to note the following when examining Table 8.

- Where a technology is assumed to already be installed for the Base Case, no additional capital cost is assumed for CSA-equivalent emissions compliance.
- Since the Base Case emissions estimate assumes that the existing SCRs will be operated annually in 2013, no additional operating cost is assumed for those SCRs

As shown, the total cost of meeting a CSA equivalent cap is estimated to be in the range of $3 billion (in 2006 dollars) in capital and about $220 million per year (in 2006 dollars) in total annual operating costs. As noted earlier, improvements may be possible on TVA's older FGD systems, such as Paradise 1 & 2 and possibly at Widow's Creek. If improvements were made to the Paradise or Widows Creek scrubbers, this would substantially reduce $SO_2$ emissions and reduce the need for FGD systems at other units in order to meet the CSA equivalent emissions cap**.** For example, if Widow's Creek 7 & 8 and all of the Paradise FGD systems controlled to 0.15 lb/MMBtu, then scrubbers could potentially be avoided at Johnsonville 6-10 and Gallatin 1 & 2. Not accounting for the cost of improving operation of the older Paradise and Widow's Creek FGD systems, this could potentially result in about $300 million in capital cost savings.

The economic analysis described here does not include the benefit to TVA of the improved fuel flexibility that emissions control equipment offers. And, this is likely to be significant since the largest variable cost at a power plant is associated with the fuel. With additional scrubbers, rather than needing to restrict the fuel sulfur levels to limit $SO_2$ emissions, TVA would be able to use higher sulfur coals as well while maintaining $SO_2$ emissions low.

**Table 8.** Estimated Cost of TVA Compliance with CSA Equivalent Over Base Case Using US EPA Cost Methodology

| Plant | Unit | CSA NOx | NOx Capital, $1000 | NOx FOM, $1000 | NOx VOM, $1000 | CSA SO2 | SO2 Capital, $1000 | SO2 FOM, $1000 | SO2 VOM, $1000 |
|---|---|---|---|---|---|---|---|---|---|
| Allen Steam Plant | 1 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Allen Steam Plant | 2 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Allen Steam Plant | 3 | SCR | $0 | $0 | $0 | FGD | $174,921 | $6,273 | $9,224 |
| Bull Run | 1 | SCR | $0 | $0 | $0 | FGD | $172,003 | $6,136 | $9,839 |
| Colbert | 1 | SCR | $32,096 | $212 | $895 | FGD | $0 | $0 | $0 |
| Colbert | 2 | SCR | $32,096 | $212 | $930 | FGD | $0 | $0 | $0 |
| Colbert | 3 | SCR | $32,096 | $212 | $887 | FGD | $0 | $0 | $0 |
| Colbert | 4 | SCR | $32,096 | $212 | $851 | FGD | $160,359 | $5,600 | $8,727 |
| Colbert | 5 | SCR | $0 | $0 | $0 | FGD | $137,631 | $4,588 | $4,769 |
| Cumberland | 1 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Cumberland | 2 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Gallatin | 1 | SCR | $41,775 | $276 | $1,003 | FGD | $0 | $0 | $0 |
| Gallatin | 2 | SCR | $41,775 | $276 | $1,007 | FGD | $142,604 | $4,805 | $6,222 |
| Gallatin | 3 | SCR | $44,270 | $292 | $1,181 | FGD | $0 | $0 | $0 |
| Gallatin | 4 | SCR | $44,270 | $292 | $1,208 | FGD | $147,890 | $5,039 | $6,923 |
| John Sevier | 1 | SCR | $32,096 | $212 | $887 | FGD | $0 | $0 | $0 |
| John Sevier | 2 | SCR | $32,096 | $212 | $889 | FGD | $0 | $0 | $0 |
| John Sevier | 3 | SCR | $32,096 | $212 | $912 | FGD | $0 | $0 | $0 |
| John Sevier | 4 | SCR | $32,096 | $212 | $872 | FGD | $160,359 | $5,600 | $9,367 |
| Johnsonville | 1 | SNCR | $3,373 | $38 | $456 | FGD | $0 | $0 | $0 |
| Johnsonville | 2 | SNCR | $3,373 | $38 | $449 | FGD | $0 | $0 | $0 |
| Johnsonville | 3 | SNCR | $3,373 | $38 | $433 | FGD | $0 | $0 | $0 |
| Johnsonville | 4 | SNCR | $3,373 | $38 | $444 | FGD | $0 | $0 | $0 |
| Johnsonville | 5 | SNCR | $3,967 | $44 | $404 | FGD | $147,059 | $5,002 | $7,592 |
| Johnsonville | 6 | SNCR | $3,967 | $44 | $418 | FGD | $0 | $0 | $0 |
| Johnsonville | 7 | SNCR | $4,668 | $52 | $468 | FGD | $0 | $0 | $0 |
| Johnsonville | 8 | SNCR | $4,668 | $52 | $484 | FGD | $0 | $0 | $0 |
| Johnsonville | 9 | SNCR | $4,668 | $52 | $468 | FGD | $0 | $0 | $0 |
| Johnsonville | 10 | SNCR | $4,668 | $52 | $432 | FGD | $163,503 | $5,744 | $7,885 |
| Kingston | 1 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 2 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 3 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 4 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |

| Plant | Unit | CSA NOx | NOx Capital, $1000 | NOx FOM, $1000 | NOx VOM, $1000 | CSA SO2 | SO2 Capital, $1000 | SO2 FOM, $1000 | SO2 VOM, $1000 |
|---|---|---|---|---|---|---|---|---|---|
| Kingston | 5 | SCR | $0 | $0 | $0 | FGD | $168,251 | $5,962 | $9,570 |
| Kingston | 6 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 7 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 8 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Kingston | 9 | SCR | $0 | $0 | $0 | FGD | $160,359 | $5,600 | $9,509 |
| Paradise | 1 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Paradise | 2 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Paradise | 3 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Shawnee | 1 | SNCR | $4,722 | $53 | $438 | FGD | $0 | $0 | $0 |
| Shawnee | 2 | SNCR | $4,722 | $53 | $430 | FGD | $0 | $0 | $0 |
| Shawnee | 3 | SNCR | $4,722 | $53 | $454 | FGD | $0 | $0 | $0 |
| Shawnee | 4 | SNCR | $4,722 | $53 | $424 | FGD | $0 | $0 | $0 |
| Shawnee | 5 | SNCR | $4,722 | $53 | $416 | FGD | $151,858 | $5,216 | $9,421 |
| Shawnee | 6 | SCR | $29,428 | $194 | $710 | FGD | $0 | $0 | $0 |
| Shawnee | 7 | SCR | $29,428 | $194 | $739 | FGD | $0 | $0 | $0 |
| Shawnee | 8 | SCR | $29,428 | $194 | $734 | FGD | $0 | $0 | $0 |
| Shawnee | 9 | SCR | $29,428 | $194 | $713 | FGD | $151,858 | $5,216 | $7,881 |
| Shawnee | 10 | CFB | $0 | $0 | $0 | CFB | $0 | $0 | $0 |
| Widows Creek | 1 | SCR | $25,573 | $169 | $568 | FGD | $0 | $0 | $0 |
| Widows Creek | 2 | SCR | $25,573 | $169 | $588 | FGD | $0 | $0 | $0 |
| Widows Creek | 3 | SCR | $25,573 | $169 | $622 | FGD | $0 | $0 | $0 |
| Widows Creek | 4 | SCR | $25,573 | $169 | $588 | FGD | $0 | $0 | $0 |
| Widows Creek | 5 | SCR | $25,573 | $169 | $605 | FGD | $0 | $0 | $0 |
| Widows Creek | 6 | SCR | $25,573 | $169 | $601 | FGD | $164,058 | $5,769 | $8,405 |
| Widows Creek | 7 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| Widows Creek | 8 | SCR | $0 | $0 | $0 | FGD | $0 | $0 | $0 |
| **TOTAL** | | | **$763,718** | **$5,328** | **$24,608** | | **$2,202,714** | **$76,551** | **$115,333** |

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## Appendix

Photos of TVA Plants - from TVA's web site

**Allen**

**Bull Run**

**Colbert**

**Gallatin**


**John Sevier**

**Kingston**

**Paradise**

**Shawnee**


**Widows Creek**