PERMIT CHECK LIST

The following people have reviewed the permit:
Reviewing Permitting Engineer: __________
Air Inspector: __________
Air Compliance Manager: __________

Date: November 26, 2012
Source Name: Virginia Electric & Power Company - Dominion Southampton Power Station
Registration No.: 61093 Id. No.: 51-175-00051
Source Location: 30134 General Thomas Highway, Franklin, Virginia 23851
Mail Address: 5000 Dominion Boulevard, Glen Allen, Virginia 23060
Source Status: ____ Greenfield _✓__ Currently operating
Source Classification: ___ Minor ___ SynMinor ___ State Major _✓__ PSD Major _✓__ TV Major
Permit Action: Conversion of primary coal boilers to biomass.

_✓__ Inspector Contacted/Consulted

Permit Action Program:
_✓__ NSR ___ SOP ___ TV ___ Maj HAP ____ General

Permit Action Type:
___ Exemption
___ New / Article 6 Modification (delete one) _✓__ Major Modification
___ Minor Amendment ___Administrative Amendment ___ Renewal
___ State Major _✓__ PSD ___ Non-Attainment ___ General Permit

_Y_ (Y/N) Permit Includes All Emission Units at Source.
_N_ (Y/N) Permit Allows Source to avoid Title V/MACT/etc.
After this permit, source is: _✓__ Major (A) ___ Minor (B) ___ Synthetic minor (SM)
(NOx, CO, PM and PM_{10} Pollutant)

Permit Application Review
_✓__ Permit application submitted, or ___ Letter Request
Application Received Date: 5/31/11
Application Complete Date: 3/12/12
Permit Deadline Date: 3/12/13
_✓__ Document Certification Form received
_n/a_ Confidential information with sanitized copy. If yes, which sections:
___ throughputs ___ individual pollutants ___ flow diagrams ___ calculations
___ process descriptions ___ other (describe)
If yes, has claim been accepted by DEQ? (Y/N) - Date of letter: ____________
_✓__ Copy of letter from local official for greenfield, or major modified sources
_✓__ Copy of letter sent to FLM if applicable. FLM notified by Mike Kiss – email dated 4/12/11
_n/a_ Notification of Affected State(s)
This permit supersedes permit(s) dated: February 3, 2011 – upon activation of the biomass handling system.

Regulatory Review (cont.)

Regulatory Review

BACT Determination (check one):

_✓_ Good Combustion Practices for the control of _CO_ meets BACT

See the BACT Analysis Section under Comments for further discussion

___ TV/SOP/BACT not applicable. (Explain)_

_✓_(Y/N) NSPS/MACT/NESHAPS Applicability: If Y, Subpart(s):

_✓_NSPS Subparts Db and Dc

_✓_ MACT Subpart DDDDD

___ NESHAPS

_N_(Y/N) Existing Rules (9 VAC 5 Chapter 40) Applicability: If Y, Rule(s):

Toxic Pollutants (check one):

___ Exempt, or ___ in compliance with 9 VAC 5-60-320, or _✓_ not evaluated ***(Reminder: remember to change the regulation to 9 VAC 5-60-220 when doing a SOP for existing sources).***

[Comments: ____________________________________]

Modeling (check one):

___ Attached (including background monitors), or

_✓_ Copy of approval letter from modeling section,

___ No modeling required by agency policy (< modeling significance levels, etc.)

Site Suitability:

_✓_ Site suitable from an air pollution standpoint, inspection date: 8/2/10, or no inspection required because _______.

_✓_ Calculation sheet(s) attached

_N_(Y/N) NSR Netting Comments (Explain Permit History):

_N_(Y/N) (CAM) Compliance Assurance Monitoring Applicable

Permit includes: _✓_ Stack Testing _✓_ CEM _✓_ VEE by source

Public Participation

_✓_(Y/N) Public Noticed. If yes, Public Notice Date: *Tidewater News*, published on March 16, 2012

_✓_(Y/N) Public Notice Comments. If yes, number and nature of comments: see the Public Response Document attached

_✓_(Y/N) Public Hearing. If yes, Public Hearing Date: April 16, 2012

EPA Review

_✓_(Y/N) EPA Review. If yes, Date proposed permit sent to EPA March 14, 2012.

_✓_(Y/N) EPA Comments. If yes, give a brief summary (see letter dated April 27, 2012)

1) Potential for CO limit reduction pending stack test results.
2) Additional performance tests due to non-uniformity of biomass origins
3) Include method to ensure compliance for sulfuric acid mist and fluoride emissions
4) All reports sent to EPA at listed address
5) Clarify applicability determination in engineering analysis write-up.

Regulatory Review (cont.)
Comments:
Introduction –

Dominion Southampton Power Station (SPS) is located at 30134 General Thomas Highway, Franklin, Virginia. This location is in an attainment area for all pollutants, and the facility is a PSD major source. The facility was previously permitted under a PSD Permit originally issued on November 22, 1989, and amended on November 12, 1992, June 20, 1995, February 6, 1996, December 5, 1996, October 15, 2010 and most recently on February 3, 2011. The facility is also permitted under minor NSR permits dated August 4, 1992, for the auxiliary boiler; November 8, 1993, for a distillate oil-fired boiler; February 20, 2002, for the Phase II Acid Rain permit; August 16, 2002, for the original Title V permit which was subsequently amended on January 12, 2004, to incorporate the provisions of the Phase II Acid Rain permit and the NOx SIP provisions. The January 12, 2004 version of the Title V permit incorporates the February 20, 2002 Phase II Acid Rain permit and the August 16, 2002, Title V permit.

Project Description –

SPS has proposed to convert the 2 primary boilers from coal fired units to 100% biomass fired units. This project also involves modifications to the material handling systems. The coal handling equipment will be abandoned-in-place and new biomass material handling equipment constructed. The SPS facility will be capable of producing 51 MW_{net} of electric power after the conversion. SPS is currently a major source with allowable emissions of SO_x, NO_x and CO above 100 tpy. After the conversion to biomass, permitted emissions from SO_x, NO_x and VOC will decrease while particulate and CO emissions will increase.

For fuel burning equipment, only the primary boilers will be modified by this project. The auxiliary boiler, emergency generator, emergency feedwater pump, emergency firewater pump engine and air compressor engine are not affected.

The biomass for the facility will be obtained from the waste wood of logging and mill operations and also sawdust. Distillate oil will be retained as the start-up fuel for the boilers.

Regulatory Review – Article 6 – Minor NSR

Article 6 applicability is based on the Net Emission Increase (NEI)[1] for the project. NEI compares uncontrolled emissions from the primary boilers firing coal at the permitted throughput (Current Uncontrolled Emissions or CUE) to the uncontrolled emissions firing biomass at 8760 hr/yr (New Uncontrolled Emissions or NUE). NEI = NIE- CUE. If the NEI is less than the modified source exemption rates listed in 9 VAC 5-80-1320 D, then the project is exempt from Article 6 permitting. Calculations are summarized in the following table:

Pollutant (tpy)	NUE - Biomass Uncontrolled @ 8760 hr/yr	CUE - Coal Uncontrolled @ Permit Throughput	NEI	Modified Source Exemption Levels	Article 6/BACT Applicable?
$PM_{2.5}$ total	2133.2	5778.6	-3645.4	n/a[2]	n/a[2]
PM_{10} total	4547.5 *	5778.6	-1231.1	10	No

[1] See VA DEQ Memo APG-354 and APG-354A for additional information.
[2] Article 6 does not address $PM_{2.5}$ emissions.

Regulatory Review (cont.)

Pollutant (tpy)	NUE - Biomass Uncontrolled @ 8760 hr/yr	CUE - Coal Uncontrolled @ Permit Throughput	NEI (tpy)	Modified Source Exemption Levels (tpy)	Article 6/BACT Applicable?
PM total	4898.0	6409.0	-1511.0	15	n/a[3]
SOx	172.6	6447.2	-6274.6	10	No
VOC	44.9	95.5	-50.6	10	No
NOx	776.6	2281.7	-1505.1	10	No
CO	1035.5	636.8	398.8	100	YES
Lead	0.2	509.4	-509.2	0.6	No
Fluorides	3.5	76.4	-73.0	3	No
Sulfuric Acid Mist	4.3	331.1	-326.8	6	No

[*] - Includes biomass material handling emissions.

As previously mentioned, the proposed project also includes a new biomass fuel handling system. Since this system is new, the current uncontrolled emissions are designated as zero and the new uncontrolled emissions are calculated based on 8760 hours/yr of operation. The biomass fuel handling system is only expected to emit PM, PM_{10} and $PM_{2.5}$. However, the only species of concern for Article 6 is PM_{10} (see footnotes #2 and 3). Dominion's application indicates and DEQ agrees that the uncontrolled emissions from the new biomass fuel handling system are 1.6 tons/yr of PM_{10}. Since this value, both alone and in combination with the decrease in uncontrolled PM_{10} emissions calculated for the primary boilers, is less than the Article 6 exemption level, the proposed project does not trigger Article 6 permitting requirements for any species of particulate matter.

CO is the only pollutant subject to Article 6. However, since CO is subject to major NSR regulations (see the Article 8 section below), CO emissions are exempted from the requirements of Article 6 [4].

Regulatory Review - Article 8 – Major NSR/PSD

For a project to be subject to PSD review it must constitute a major source by itself or occur at an existing major source, cause a Significant Emission Increase (SEI) and cause a Significant Net Emission Increase (SNEI) as these terms are defined in the Article 8 Regulation at 9 VAC 5-80-1615. SPS is currently a PSD major source because it is one of the 28 listed source categories (a fossil fuel-fired steam electric plant capable of more than 250 MMBtu/hr) and has the potential to emit (PTE) greater than 100 tpy of SOx, NOx and CO.

SEI = PAE – BAE and

SNEI = SEI + contemporaneous increases – contemporaneous decreases.

SEI and SNEI calculations are summarized in the following table:

[3] Per 9 VAC 5-80-1320 D.3, a source determined to be exempt for PM_{10}, shall be considered exempt for PM.
[4] Per 9 VAC 5-80-1100 H, the provisions of Article 6 are applicable to sources "…to the extent that such sources and their emission are not subject to the provisions of the major new source review program."

Regulatory Review (cont.)

Pollutant (tpy)	BAE Coal[5]	PAE Biomass[6]	SEI	SNEI	PSD Significant Rates	SEI Significant?	SNEI Significant?
$PM_{2.5}$ total	88.2	98.0	9.9 *	9.9*	10	No	No
PM_{10} total	88.2	102.5	14.9 *	14.9 *	15	No	No
PM total	91.3	114.7	24.9 *	24.9 *	25	No	No
SOx	118.0	38.2	-79.8	-79.8	40	No	No
VOC	2.5	42.4	39.9	39.9	40	No	No
NOx	724.4	412.4	-312.0	-312.0	40	No	No
CO	54.6	916.5	861.9	861.9	100	YES	YES
Lead	0.004	0.15	0.1	0.1	0.6	No	No
Fluorides	0.5	3.4	2.9	2.9	3	No	No
Sulfuric Acid Mist	1.2	8.1	6.9	6.9	7	No	No

* - Includes new/modified biomass material handling emissions of 0.1 tpy for $PM_{2.5}$ (total), 0.6 tpy for PM_{10} (total) and 1.5 tpy for PM (total).

Since the SEI and SNEI calculations for CO are above the PSD significance levels, and the project occurs at an existing major source, this project is a major modification. As such, the conversion of the primary boilers from coal-fired to biomass-fired is subject to PSD review for CO and BACT applies (see the BACT Analysis section for further discussion.)

The SEI and SNEI values above for SO_x, NO_x, CO and lead were calculated by comparing the post-change Projected Actual Emissions (PAE) to the Baseline Actual Emissions (BAE). SPS has elected to use potential emissions in place of PAE for these pollutants.

The SEI and SNEI values for PM, PM_{10}, $PM_{2.5}$, VOC, Sulfuric Acid Mist and Fluorides were determined by the following equation:

Baseline actual emissions + the applicable PSD significance levels – 0.1 ton= combined annual limit for both boilers in tpy
For particulate calculations, SEI includes those emissions from the biomass handling equipment in addition to the boilers.

To determine the permit limits, the equation above was further manipulated as follows:

Combined annual limit for both boilers in tpy / 2 = annual emissions for each boiler in tpy

[5] Baseline Actual Emissions (BAE) with boilers firing coal from July 2007 through June 2009.
[6] Predicted Actual Emissions (PAE) with boilers firing biomass, note that Dominion has elected to use potential emissions in place of predicted actuals as stated in the May 2011 application.

Regulatory Review (cont.)

The annual emissions for each boiler were then converted to lbs per hour using 8400 hr/yr as an operating limitation.

Article 8 defines BAE for an existing electric utility steam generating unit as "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner within the five-year period immediately preceding when the owner begins actual construction of the project. The board will allow the use of a different time period upon a determination that is more representative of normal source operation."

SPS anticipates that construction will begin in July 2012 which means the five-year period would start in July 2007. The initial application dated May 2011 requested the use of a BAE time period from January 2006 through December 2007. This is outside of the five-year period as described above. Further discussions with SPS on this matter resulted in a change to the BAE period[7] which is within the five year standard, July 2007 through June 2009.

All particulate limits contained in the permit are total (i.e. filterable plus condensable) unless explicitly stated otherwise.

BACT Analysis –

The BACT Analysis is a 5 step process performed on a case-by-case basis and is pollutant specific. For SPS, the top-down BACT determination is completed for CO only. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel.

Step #1: Identify Potentially Feasible Control Options

For SPS, a facility with existing coal-fired stoker boilers, BACT determinations are based on CO controls for stoker-type biomass boilers. Alternatives to stoker-type biomass boilers themselves and controls on alternatives to stoker-type biomass boilers are outside the scope of this project ("redefine the source") and therefore are not considered as part of the BACT analysis[8]. SPS conducted a review of the RACT/BACT/LAER Clearinghouse (RBLC) and included a table of results in their May 2011 application in Appendix C. DEQ-TRO's review of the RBLC database returned the same results as SPS, once the alternatives described above were removed.

SPS listed combustion controls/good combustion practices (GCP) (i.e. an enhanced overfire air (OFA) system) and post-combustion controls (i.e. regenerative thermal oxidation (RTO) or catalytic oxidation) as potential controls for CO.

The enhanced OFA system proposed/designed by the boiler manufacturer (Babcock & Wilcox) is required to provide the optimum combustion characteristics. Where the existing OFA system is capable of 25 – 30% of the total combustion air, the enhanced system can provide ~50% for the biomass. B&W predicts that using the existing OFA would result in CO emissions of 0.8 lb/MMBtu versus the enhanced system at 0.30 lb/MMBtu.

Step #2: Eliminate Technically Infeasible Options

Of the three potential control options listed in Step #1, only the RTO is eliminated as technically infeasible. The application states "RTO technology is normally applied to exhaust streams …in which the only

[7] See Dominion letter dated January 17, 2012.
[8] See PSD Appeal No. 91-39 by the Environmental Appeals Board.

Regulatory Review (cont.)

contaminant is gaseous organic solvents (i.e. VOC). This technology could potentially be installed downstream of the particulate removal systems for the Southampton biomass boiler conversion. However, all qualified vendors of RTO systems do not recommend this technology due to the potential fouling of the regenerative media… This will result in an unacceptable frequency of forced shutdowns to the operation."

DEQ-TRO has confirmed this issue with RTO's for this particular project. Thermal oxidizers use high temperatures to oxidize CO to CO_2 and water. RTO's are subject to fouling by PM in the flue gas. Therefore the RTO would need to be placed after the PM controls. It is for these reasons, as well as finding no documentation of RTO's used on biomass-fired boilers, that this control option is considered technically infeasible from a practical standpoint and will not be discussed further in this BACT analysis.

Step #3: Rank Remaining Control Options by Control Effectiveness

Baseline emissions are based on emission guarantees from the boiler manufacturer (B&W) and are consistent with the information available in the RBLC.

Control Option	Removal Efficiency	Emission Rate (lb/MMBtu)
Catalytic Oxidation w/ Recuperative Heat Exchangers	> 70 – 90%	< 0.10
Good Combustion Practices	Baseline	0.30

Step #4: Evaluate Economic, Environmental and Energy Impacts

SPS states that the catalytic oxidizer system will result in additional fuel costs for the reheat burner with no increase in the plant's electrical output, as well as pressure drop increase which will require additional internal electricity consumption. The fuel burning to operate the catalytic oxidizer will increase emissions, namely GHG constituents. Additionally, the system would oxidize ammonia slip from the SNCR and residual SO_2 in the flue gas to H_2SO_4. Thus resulting in an estimated increase of 30 tpy of NO_x and 48 tpy of H_2SO_4.

SPS also provided a cost analysis for the catalytic oxidizer with recuperative heat recovery. DEQ-TRO found some minor discrepancies with the analysis supplied and the guidelines typically used. The differences include the use of an 8% interest rate by SPS where EPA uses a 7% interest rate[9]. Also, the control efficiency is listed as having a range of >70 – 90% removal of CO but the evaluation is only conducted at 80% removal. EPA OAQPS guidance states direct installation costs (DIC) is approximated to be 30% of the purchased equipment costs (PEC). SPS estimates the DIC to be roughly equal to the PEC. Further information from SPS[10] illustrates that due to the retrofit nature of this project and actual site conditions (i.e. considerable field work, small footprint, vertical configuration, etc.) the DIC estimates provided are justifiable. Even with these corrections, the $/ton of CO removed is too high at $8043/ton of CO removed.

Step #5: Selection of BACT

The three control options presented were RTO, catalytic oxidation with recuperative heat exchanger and GCP. The RTO was determined to be practically infeasible due to PM fouling and no demonstrated use of an RTO on biomass-fired boilers. Catalytic Oxidation was determined to have an adverse environmental impact (i.e.

[9] EPA applies the current social interest rate used by the White House Office of Management and Budget. Since 1993, this has been set at 7%.

[10] See email dated February 15, 2012.

Regulatory Review (cont.)

emission increases related to the additional fuel burning and ammonia slip and SO_2 oxidation) as well as being cost prohibitive.

Therefore, DEQ-TRO is in agreement that GCP meets BACT. The proposed limit for CO is 0.30 lb/MMBtu.

Regulatory Review – MACT/State Toxics

SPS is a major source of HAPs and as such, the boilers are subject to MACT DDDDD[11]. In accordance with 9 VAC 5-60-300 C, the state toxics regulation does not apply to a facility covered by a MACT. No MACT requirements are included in this permit. Once the status of the Boiler MACT (stay/vacatur/reconsideration) is finalized, the necessary requirements will be included in the Title V permit.

The SPS boilers are not "new" because they were constructed prior to June 4, 2010. This project to retrofit the coal boilers to fire biomass represents about 5% of the cost to construct a new biomass boiler; therefore, these units are subject to the standards for "existing" boilers under the MACT. Based on the application, the units will meet those standards.

Previous permits listed several HAPs under the primary coal boiler emission limit condition (in lb/day limits). These limits have been removed due to the applicability of the Boiler MACT.

Regulatory Review – NSPS

SPS is currently permitted as a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr which is subject to NSPS Subpart Da. EPA has confirmed[12] that NSPS Da will no longer apply to the boilers "…as wood (biomass), under Section 60.40Da, is not considered, and not defined, as a fossil fuel but Subpart Db will apply to these emission sources as they meet the definition of an affected facility under those regulations in Section 60.40b which accounts for all fuels."

Regulatory Review – GHG's

After July 1, 2011, modifications at a facility otherwise subject to PSD with CO_2e emissions greater than 75,000 tpy are subject to PSD review for GHG's. EPA has deferred the applicability of PSD requirements to biogenic CO_2 emissions from bioenergy and other biogenic stationary sources (i.e. electric utilities burning biomass fuels.) Emissions of GHG (i.e., methane and N_2O) for the biomass project (including start-up operations using distillate oil) at SPS are included in the calculations and shown to be 56,395 tpy CO_2e which is less than the 75,000 tons $CO2_e$ /yr threshold. Therefore, GHG from the current project is not subject to PSD review.

SPS has withdrawn the GHG BACT Analysis from its application.[13]

Public Participation –

In accordance with 9 VAC 5-80-1775 A - C, SPS placed an ad in the Tidewater News on July 27, 2011. The informational public briefing was held on September 14, 2011.[14]

[11] On January 9, 2012, the DC Circuit Court vacated EPA's stay on the Boiler MACT. However, the legal status of the rule itself does not alter the outcome that the SPS boilers are subject to Subpart DDDDD.

[12] See EPA letter dated February 21, 2012, Re: Applicability Determination for Biomass Fuel Change.

[13] See Dominion letter dated February 9, 2012.

Regulatory Review (cont.)

As provided by 9 VAC 5-80-1775 E and F, DEQ placed an ad in the Tidewater News on March 16, 2012. The public comment period ended on April 30, 2012 (15 days after the date of the public hearing). The public hearing was held on April 16, 2012 at 7:00 pm at the Paul D. Camp Community College, Franklin Campus. Fourteen people signed the attendance record, an estimated 16 individuals were present.

Please see the Public Response Document (attached) for a summary of public comments and DEQ responses pertaining to this project.

Modeling -

See the modeling report dated March 9, 2012, for a detailed discussion on air quality impacts.

In summary, the modeled results for CO (1-hour and 8-hour averaging periods) were less than the applicable Significant Impact Levels and are shown below. Additionally, there are no adverse impacts to soils and vegetation and no significant emissions from secondary growth as a result of this project. CO is not one of the pollutants of concern that is evaluated for affecting visibility, and therefore a visibility impairment analysis was not required. Also, there are no PSD increments for CO so a PSD increment analysis was not required.

Pollutant	Averaging Period	Max. Predicted Concentration from Proposed Facility ($\mu g/m^3$)	Class II Significant Impact Level ($\mu g/m^3$)
CO	1-hour	66.4	2,000
	8-hour	36.4	500

All pollutants that affect visibility and acidic deposition (i.e., AQRVs) will decrease as a result of this project. The US Forest Service and National Park Service each stated that they would not require any AQRV analysis for this project.

Aux. Boiler –

The 2/3/11 permit analysis discusses the auxiliary boiler and its hours of operation. Specifically, the auxiliary boiler does not have an annual hourly limit, yet the combined primary and auxiliary boiler emission limit condition mentions the aux. boiler operating at 360 hr/yr. As discussed by email dated January 25, 2011, the reason is "that the auxiliary boiler can be used as a means to provide steam to the Ashland Chemical plant when the main boilers were not operating. As such, the auxiliary boiler would provide the balance of 8760 hr/yr that was not supplied by the main units." With the 2/3/11 coal permit, (and previous permits) the main boilers were limited to a maximum 8400 hr/yr, and consequently, the aux. boiler could operate for 360 hr/yr (total 8760 hr/yr). This hourly assumption (360 hr/yr) for the aux. boiler continues to be used to determine the combined

[14] See Dominion email dated September 17, 2011.

Regulatory Review (cont.)
primary and aux. boiler emissions[15] due to the assertion by SPS that "the two main boilers are the only combustion sources that are proposed to be modified[16]…."

Other Items –

The previous permits contained a condition[17] on boiler operation which stated that the coal boilers "shall be operated at a heat input rate not to exceed the rate at which compliance with emission limits….has been demonstrated by stack emission tests." This condition has been replaced with condition #29, which limits the maximum hourly and total (combined) annual heat input for the biomass boilers. With the old condition, though the "nominal" rating for the boilers might be 400 MMBtu/hr, if stack tests show compliance while firing at a slightly higher rate, then the boilers could continue to fire at the higher rate while calculations and permit limits were determined using the nominal value. The new condition and stack testing requirements will ensure compliance with permitted limits.

The 2/3/11 permit contained limitations for SO_2 based on the combustion of coal. The current requirements are 0.162 lb/MMBtu, 61.3 lb/hr, and flue gas desulfurization with a 92% control efficiency. This switch to biomass reduces the available sulfur (4,000 TPY reduction in uncontrolled emissions) such that review of the limitations is necessary. Reviewing the RBLC for similar facilities, no control efficiency requirements have been found with similar emission limitations. Additionally, recently permitted biomass boilers in Virginia have higher lb/MMBtu limitations (0.017 and 0.06 lb/MMBtu) and no control efficiency requirements. Therefore, the requirements of the proposed permit (flue gas desulfurization meeting at least 0.0125 lb/MMBtu and 4.9 lb/hr) are appropriate.

Final Recommendation: Recommend Approval.

Environmental Engineer's Signature: ______________________________

Air Permit Manager's Signature: ______________________________

[15] See Condition #37 contained in this permit.
[16] Application dated May 2011, section 3.1.
[17] February 3, 2011 permit condition #26.