VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office

INTRA-AGENCY MEMORANDUM

Permit Writer	Berkeley			
Memo To	Air Permit File	**Date**	5/22/12	
Facility Name	Virginia Electric & Power Company – Altavista Power Station			
Registration Number	30859			
County-Plant I.D.	031-00156			
UTM Coordinates (Zone 17)	653.4	**Easting (km)**	4109.3	**Northing (km)**
Elevation (feet)	600			
Distance to Nearest Class I Area (select one)	109	**SNP (km)**	51	**JRF (km)**
FLM Notification (Y/N)	Y	**Required if less than 10K (minor), 100K (state major)**		
NET Classification (A, SM, B)	A	**Before permit action**	A	**After permit action**
Title V Major Pollutants	NOx, SO2, & CO	**Before permit action**	NOx & CO	**After permit action**
PSD Major Source (Y/N)	Y	**Before permit action**	Y	**After permit action**
PSD Major Pollutants	NOx, SO2, & CO	**Before permit action**	NOx & CO	**After permit action**

I. Introduction

The Altavista Power Station (APS) is owned and operated by Virginia Electric and Power Company (Dominion) and is located at 104 Wood Lane in Altavista (Campbell County) Virginia. The facility generates electric power for sale. On 5/31/11, BRRO received an application dated 5/25/11 for the conversion of the station from a coal, wood dust, and wood chip fired facility to one whose primary fuel is biomass.[1] Included with the application was the Local Governing Body Certification Form signed on 5/17/2011 by the Altavista Assistant Town Manager.

APS currently operates under the following permits:

- A combined PSD and Article 6 permit last revised 1/30/08,
- A State Operating permit dated 1/9/03, and
- A Title V permit with an effective date 1/1/09

II. Emission Unit(s) / Process Description(s)

The scope of the current project is:

(1) installation of a new biomass fuel handling system; and

[1] Biomass is described more completely in Section II below. Also, No. 2 fuel oil and natural gas will remain the startup fuels for the site's two primary boilers.

(2) conversion of the site's two stoker boilers (Ref. No. 001 and 002) from coal and wood fired units to biomass fired units; including changing three dry ash handling systems to wet systems.

With this conversion each stoker boiler will have a maximum rated capacity of 394 MMBtu/hr, dry fuel basis. As part of the boiler conversion, the boilers will be retrofitted with a redesigned combustion air delivery system. The biomass fuel will be virgin, forest-derived, wood residue from logging and mill operations and sawdust, and will not include resinated materials, paints, coatings, plastics, or the like. (See Section X.C. below for further discussion of the definition of biomass fuel.)

Biomass will be delivered to APS by truck. The new biomass handling system includes: hydraulic truck dumpers, live bottom hoppers, conveyors, screens, a stacker/reclaimer storage system, and metering bins[2].

As a result of the fuel conversion, APS anticipates a significant reduction in the quantity of ash to be handled; as well as changes in the character of the ash. After the conversion, bottom ash directly from the boiler and fly ash from the existing mechanical collectors on the boiler exhaust will be quenched and moved by conveyor to roll-off boxes by wet ash handling systems.[3]

The sulfur content of biomass is very much less than that of coal, but the existing flue gas desulfurization (FGD) system will continue to operate; principally to cool/quench any embers in the flyash before they reach the fabric filter but also to demonstrate compliance the SO2 and H_2SO_4 limits.[4]

The following other equipment is currently on site and permitted but is not being physically or operationally changed by the fuel conversion:

(1) auxiliary NG/DO boiler,
(2) diesel engines,
(1) ammonia handling system, and
(1) above-ground 100,000 gallon distillate oil tank.
(1) Lime handling
(1) Wood dust

As part of this project, the coal handling system equipment will be abandoned in place except where physical interferences with new equipment (e.g., the biomass handling system) require its removal. It should be noted that the impact on the ambient air of future use of any

[2] See Figures 2-2, APS Plot Plan, and 2-3, Process Flow Diagram, in the permit application for equipment arrangement.
[3] Ash collected from the operation of the boilers will be disposed of off-site.
[4] (a) There are currently SO_2 CEMs in place at APS. (b) Additional acid gas control/reductions may be required by future regulations (e.g., the Boiler MACT). (c) Also, similar to recently permitted facilities in the Virginia, the alkalinity of the wood ash is expected to reduce the sulfur compound emissions.

portion of that abandoned system (e.g., rail car unloading station equipment) to handle biomass material would be considered cause for reconsideration of the current project determinations[5].

Emissions from the project consist of combustion by-products (mainly oxides of nitrogen (NOx), carbon monoxide (CO), with lesser amounts of particulate matter, volatile organic compounds (VOC), and hazardous air pollutants (HAPs or toxics[6]). Particulate from the project is also generated by the new biomass handling system.[7]

III. Regulatory Review

A. 9 VAC 5 Chapter 80, Part II, Article 6 – Minor New Source Review

As stated in 9 VAC 5-80-1100 C, Article 6 regulations do not apply to stationary sources that are exempt under 9 VAC 5-80-1320. To be exempt under 9 VAC 5-80-1320, a project must be exempt from subsections B through D as a group and subsection E or subsection F. If a project meets these criteria, it is exempt from permitting under Article 6.

Subsection B of 9 VAC 5-80-1320 (size exemption criteria) and C (new sources) are not applicable to the currently requested changes. Subsection D does apply to this modified source. Per that subsection, sources with net emission increases (NEI) less than all the specified emissions rates are exempt. By definition, the NEI is any increase in the uncontrolled emission rate from the particular change[8]. As shown in Attachment A to this analysis there is a NEI for CO so the current project is considered a modification.[9] Furthermore, the NEI for CO exceeds its exemption threshold contained in 9 VAC 5-80-1320 D. However, as discussed in Section III.B below, CO is also subject to permitting under Article 8, Major New Source Review. In accordance with 9 VAC 5-80-1100 H, the provisions of Article 6 are applicable to sources "…to the extent that such sources and their emissions are not subject to the provisions of the major new source review program." Therefore, no criteria pollutant is subject to Article 6 review.

As discussed in Section III.F below, HAPs emissions from the primary boilers at APS are subject 40 CRF 63, Subpart DDDDD (the Boiler MACT). A facility subject to a MACT is exempted from review under the State Toxics regulations (9 VAC 5-60-300 C) and as such is exempt pursuant to 9 VAC 5-80-1320 F.

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[5] That is, coal is being removed as a possible fuel for combustion in the boilers with this action. The equipment supporting that activity is removed from the emissions calculations for the facility and therefore, restarting the equipment for any purpose is considered construction of a new unit at the facility.

[6] HAP is the nomenclature for a list of pollutants in Section 112 of the Clean Air Act (as amended by 40CFR63.60). A "toxic pollutant" (toxic) is a pollutant from the same list but is regulated only by the State pursuant to 9VAC5-60-200 *et seq.* or 9VAC5-60-300 *et seq.* Because of the regulatory difference, these terms should not be used interchangeably.

[7] Several pieces of the ash handling system are being converted to wet systems, which is a change that does not increase emissions.

[8] There is a second aspect included in the Article 6 definition of NEI, i.e., the definition of NEI also includes other increases and decreases that are directly resultant from the particular change. In accordance with current guidance (Determining Minor NSR Permitting and BACT Applicability, dated 3/17/09), the second part of the NEI total does not apply to the current project at APS since no past permit determinations for this facility have been based on bottlenecked emissions.

[9] CO is the only pollutant for which there is a NEI from this project.

Therefore the current project is exempt from the permitting requirements of Article 6. However, this project does involve, for example, significant changes to existing Article 6 monitoring and recordkeeping requirements and therefore fits the criteria for use of significant amendment procedures per 9 VAC 5-80-1290.

B. 9 VAC 5 Chapter 80, Part II, Article 8 - PSD Major New Source Review and Article 9 – Nonattainment Area Major New Source Review
(See Attachment B, Article 8 applicability for calculations)

1. As designated in 9 VAC 5-20-205, Campbell County is a PSD area for all pollutants. APS has been a PSD major source since its initial construction and operation as allowed under the permit dated 2/21/90. The provisions of PSD apply to any project at an existing major stationary source[10], and no owner shall begin actual construction of any major modification at an existing major source without first obtaining a permit[11]. By definition a "major modification" means, in part, "… any physical change in or change in the method of operation of a major stationary source than would result in a significant emissions increase…"

   Per 9 VAC-80-1605G, a project is a major modification for a regulated NSR pollutant, in part, "…if it causes…a significant emission increase …" and "…the procedure for calculating whether a significant emissions increase will occur depends upon the type of emissions units being modified…" The actual-to-projected-actual test is for projects that only involve existing emissions units, and the actual-to-potential test is for projects that only involve construction of new emissions units. The hybrid test is for projects that involve both existing and new unit emissions units.

   The primary boilers are existing emissions units and are therefore subject to the actual-to-projected-actual test. The Projected Actual Emissions (PAE) for the boilers are calculated[12], and the differences between the PAE and the BAE for the primary boilers are shown as a subtotal in Attachment B. No credits for "excludable" emissions as described in paragraph c of the definition of Projected Actual Emissions have been included in the calculations.

   The only new emissions unit described in the permit application is the biomass fuel handling system. Actual-to-Potential emissions for this system are calculated using a permit limited allowable biomass throughput[13].

[10] 9 VAC 5-80-1605
[11] 9 VAC 5-80-1625
[12] The current draft permit effectively limits both the short term (e.g., lb $_{POLLUTANT}$ / hr) and long term (e.g., hours of operation/yr) emissions, and therefore in accordance with paragraph "d" of the definition of projected actual emissions the potential to emit is used in this calculation.
[13] Actual emissions for new emission units that have not begun operation is zero.

The "Project Total" changes in emissions are the pollutant-by-pollutant sum of the Actual-to-Projected-Actual and the Actual-to-Potential emissions increases. As shown in Attachment B, the only pollutant emitted above its respective PSD significant emission rate is CO[14]. Therefore, CO emissions from the biomass project at APS are subject to PSD review.

2. Beginning on January 2, 2011, GHG is a pollutant that must be considered for regulation as a "regulated NSR pollutant" for projects that occur at any major stationary source. GHG is subject to regulation under the PSD program if a major modification causes an increase in CO_2 equivalents (CO_2e[15]) of at least 75,000 tons per year[16]. Potential emissions of GHG for the biomass project at APS are calculated in Attachment C to this analysis. The GHG emission rate after the project shown (56,395[17] tons $_{CO2e}$ /yr) is less than the 75,000 tons CO_2e /yr threshold. Therefore, GHG is not subject to regulation[18].

C. <u>9 VAC 5 Chapter 50, Part II, Article 5 - NSPS</u>

After the biomass conversion, fossil fuel firing capacity will be less than 250MMBtu/hr.[19] Therefore, the boilers will no longer be considered subject to NSPS Da, but will be considered subject to NSPS Db.[20] However, with Dominion's revision to the application dated 1/31/12 addressing PM emissions, the biomass project does not fit the NSPS definition of a modification since it does not "…result in an increase in the emission rate of a pollutant to the atmosphere of any pollutant to which a standard applies…[21]"

D. <u>9 VAC 5 Chapter 60, Part II, Article 1 - NESHAPS</u>

There are no applicable NESHAPS (40 CFR Part 61) standards.

E. <u>9 VAC 5 Chapter 60, Part II, Article 2 - MACT</u>

APS is a major source of hazardous air pollutants (HAPs). The biomass boilers are

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[14] Dominion has chosen not to quantify any contemporaneous decreases.

[15] CO_2e is the emission rate of each GHG species multiplied by its respective global warming potential (GWP) from 40CFR Part 98.

[16] On 7/20/11 the "Deferral for CO2 Emissions from Bioenergy and Other Biogenic Sources under the PSD and Title V Programs" was published by EPA at 76 FR 43490. That action deferred, for a period of 3 years (i.e., until 7/21/14), the application of PSD and Title V permitting requirements to biogenic CO2 emissions. Effective 9/9/11, Virginia's definition "Subject to regulation" at 9 VAC 5-85-30 was rewritten to incorporate EPA's deferral saying "…prior to 7/21/14, the mass of GHG CO2 shall not include CO2 emissions resulting from the combustion …of nonfossilzed and biodegradable organic material…"

[17] This value does not represent the emissions increase caused by the project because the BAE has not been considered.

[18] On 2/14/12 DEQ received Dominion's letter dated 2/9/12 (documentation certification dated 2/10/12) requesting that DEQ process the permit application in accordance with current applicable requirement (i.e., not including CO2 in GHG) for the project. Therefore, the PSD application for GHG is considered withdrawn.

[19] The only remaining fossil fuels are the startup fuels, NG and No. 2 fuel oil. Per Dominion's 12/13/11 email, the heat input during startup is 27.5 MMBtu/hr/boiler.

[20] On 1/25/12 DEQ received EPA's informal concurrence that after the biomass conversion Db will be the applicable NSPS. DEQ received EPA's letter dated 2/21/12 formally concurring that Db is the applicable NSPS.

[21] NSPS Db includes emissions standards for PM, SO2, and NOx. Note: Because of the test methods specified in Db the regulated NSPS pollutant is filterable PM.

subject to 40 CFR 63 Subpart DDDDD (Boiler MACT), which was promulgated on 3/21/11. The legal status of that MACT is currently under reconsideration by EPA[22]; however, the boilers are in the existing source category (i.e., they were constructed before the proposal date). The permit application (Appendix B, Sheet 4) shows the combined emission rates for individual HAP and total HAPs for both boilers. No requirements of the Boiler MACT are included in the current NSR permit due to the reconsideration; however, the application shows the boilers are expected to comply with the requirements that have been promulgated.[23] The applicable requirements after reconsideration/vacatur resolution will be incorporated into the Title V permit.

F. State-Only Enforceable Under 9 VAC 5-80-1120 F

None. As discussed in Section III.E above, the biomass boilers are subject to the major source boiler MACT. However, due to the evolving status of that MACT rule, as a courtesy, Dominion included in the permit application calculations to indicate which state toxics are expected to be emitted at or above their respective exemption rate (See Appendix B, Sheet 4). These toxics were modeled by Dominion and their permit application indicates each is emitted at less than its respective SAAC (See Table 6-5 in the application). It should be noted that there is no regulatory requirement for this review; therefore, DEQ has not made an independent assessment of the emission rates used in Dominion's review of state toxics. Also, since the state toxics regulations are subsumed by the boiler MACT, the need for APS to retain its current state-only enforceable State Operating Permit (SOP) which was targeted solely at toxic emissions from the coal fired primary boilers is not apparent. A determination on the fate of that SOP does not need to be made before the current NSR determination may be completed.

[22] On 1/9/12, 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 APS boilers are subject to Subpart DDDDD. The most recent statement of the subpart's existing source compliance date is 3/21/14, as shown in the amendments published on 3/21/11 at 76 FR 15664.

[23] See application Page 3-2.

IV. Best Available Control Technology Review (BACT) (9 VAC 5-50-280 and 9 VAC 5-50-260)

A. Article 8, PSD, BACT

The Article 8 control technology review regulations require a PSD major modification to apply Best Available Control Technology (BACT) for each regulated NSR pollutant for which a project would result in a major modification at the source, and this requirement applies to each emissions unit at which an emission increase in that pollutant would occur as a result of the project. As shown in section III.B above, the only pollutant for the biomass conversion project at APS results in a major modification is CO.

The permit application included the 5 step, top-down BACT analysis for CO as required by the EPA guidance document "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" (NSR manual).

Step 1: Identify all control technologies:

The permit application identified Regenerative Thermal Oxidizers (RTO), and Catalytic Oxidation as possible add-on emissions controls for CO, and Good Combustion Practices (GCP) as a possible inherently lower-polluting process[24] for that pollutant. DEQ's independent review of the RACT/BACT/LEAR Clearinghouse (RBLC) concurs that Catalytic Oxidation and GCP are available options.

Step 2: Eliminate technically infeasible options

RTOs typically employ large beds of heat transfer media and a flow reversing system to minimize the heat input requirements to this control technology. DEQ's experience in the wood products industry indicates that in wood combustion exhaust streams the heat transfer media beds are subject to rapid fouling/blockage. Therefore, DEQ considers the permit application assertion that "…all qualified vendors of RTO systems do not recommend this technology due to potential fouling of the regenerative media…" as not unexpected. Therefore, RTOs are eliminated as a technically infeasible option.

Step 3: Rank remaining control technologies by effectiveness

Of the remaining two control technologies, Catalytic Oxidation is clearly the more effective approach, with CO removal efficiencies as high as 90%. Consideration of GCP as the baseline case is consistent with page B. 37 of the NSR manual which says:

> "…baseline emissions are essentially uncontrolled emissions, calculated using the realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emission may be assumed to be the emissions for the lower polluting process itself."

[24] Page B.5 of the NSR manual indentifies inherently lower-polluting processes as appropriate of consideration as an available control alternative.

Step 4: Evaluate most effective controls and document

In the permit application the cost effectiveness of Catalytic Oxidation for CO control at APS was calculated (See Appendix D, Sheet 1) using the procedures as shown in Chapter 2 of the EPA Air Pollution Control Cost Manual; 6th Edition (QAQPS manual) for Incinerators.

Several line item entries in that calculation warrant additional comment.

- Page 2-10 of the OAQPS manual states that the operating temperature range for catalytic oxidizers is 300 to 900^{O}F. As shown on the drawing 636010F01, "Process Flow Diagram[25]" downstream of the particulate control devices the design temperature is ~ 190^{O}F, and therefore an exhaust gas reheat system is required to allow the catalytic oxidation reaction to occur.
- A fundamental approach used by in the OAQPS calculation, is to estimate values for most line items as a percentage of the purchase equipment cost (PEC) (e.g., contractor fees = 0.1 x PEC; performance test = 0.01 x PEC). In the OAQPS calculation, the Direct Installation Cost (DIC) estimate is shown as 0.3 x PEC + site preparation (SP) + the building (Bldg.). The value of DIC shown in the application is approximately 1.01 x PEC. The required reheat system includes both a gas-to-gas heat exchanger (HX) to limit the reheat energy input required and a reheat burner to raise the exhaust gas temperature to the required range. The HX in the BASF corp. proposal mentioned above will stand approximately 70 ft tall and weighs approximately 270 tons. Furthermore, the transmittal email indicates that: (1) the BASF HX design requires substantial non-standard wind and seismic loading considerations, and (2) since this is a retrofit installation of end-of-pipe controls, due to the available building footprint, the installation configuration will also drive up the installation costs. Therefore the higher than normal multiplier of PEC for the site specific installation is considered defensible.
- It is noted that the "equipment price forecast" of $3.3 million dollars shown of the AIR PREHEATER DATA SHEET included with the BASF data matches the PEC for that line item on Appendix D, Sheet 1.
- Not unexpectedly the Direct Operating Costs (DOC) for the oxidation catalyst includes a substantial line item for annual auxiliary fuel cost for the reheat burner.
- Current EPA practice is to use an interest rate of 7%. Appendix D, Sheet 1 uses 8%. The estimated reduction in Capital Recovery (CR) is approximately $90,000 less than the value based on 8%.

[25] Dwg. 636010F01 received on 2/10/12 (4:10PM) as an attachment to Dominion's email Labrie to Berkeley. Also attached to that email was a copy of the BASF Corp. budgetary proposal for a CO Catalyst system. BASF's warranty indicates that their system must be downstream of particulate control saying that the owner must "…eliminate masking agents, such as, but not limited to, noncombustible particulates..."

Therefore, at a control efficiency of 90% and adjusting the value of the interest rate, Total Annual Cost shown in Appendix B, Sheet 1 is considered defensible[26]. Including the EPA recommended interest rate; the cost effectiveness is $8,066 per ton of CO removed.

Step 5: Select BACT

While Federal guidance is clear that there can be no fixed or "bright line" cost established as representative of BACT, a cost effectiveness of greater than $8000 per ton is considered prohibitive, and therefore GCP at 0.3 lb/MMBtu per submitted vendor guarantee[27] is considered BACT for the purposes of Article 8.

B. Article 6 BACT

Not applicable. Article 6 permit amendments procedures do not subject a project to BACT review.

V. Summary of Actual Emissions Increase

As a result of the biomass project at APS there is a reduction in the potential to emit of all permitted pollutants except CO. For the CO, the potential to emit is increases by approximately 280 tons per year.

VI. Dispersion Modeling

The project is subject to PSD review for CO and a modeling analysis is a required portion of that review process. The following is a brief summary of the findings of the full modeling report dated 3/9/12 by DEQ's Office of Air Quality Assessments (OAQA)[28].

There are no PSD increments for CO so a PSD increment analysis is not required.

CO is not one of the pollutants of concern that is evaluated for affecting visibility, and therefore a visibility impairment analysis was not required.

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

The air quality modeling analysis submitted by Dominion conforms to the required modeling methodology.

NAAQS Analysis:

The modeling results for CO (1-hour and 8-hour averaging periods) were less than the applicable Significant Impact Level (SIL) and therefore, a full impact analysis for CO and its averaging periods was not required.

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[26] Although Dominion shows the CO removal efficiency as from 70 to 90% on page 5-5 of the application, the Appendix B, Sheet 1 calculations use 80% CO removal efficiency and 8% interest to calculate cost effectiveness as $9,320 per ton of CO removed.

[27] See PERFORMANCE GUARANTEES received on 1/31/12 as an attachment to Dominion's email Labrie to Berkeley.

[28] See the document list included in the draft permit, item #101.
http://ecmiis/ECM/ViewDocument.aspx?ViewDocumentMode=DocContent&DocId={A8F5FDE0-DD24-4C6E-80B4-1242DDD735B7}

NAAQS conclusion: Based on the OAQA's review of the Class II modeling analysis the impacts from the project were insignificant, and the project does not cause or significantly contribute to a predicted violation of any applicable NAAQS.

Additional Impact Analysis:
Soils and Vegetation: No adverse impact on soils or vegetation was identified.

Growth: No significant emissions from secondary growth during construction and operation of the facility are anticipated.

VII. Boilerplate Deviations

A. Historically the APS permit is a combined minor and major NSR permit. In 2008 the then new PSD regulations required a separation of PSD and any other permitting requirement (e.g., Article 6). Therefore, the 2008 action consisted of two NSR permits in one NSR document (PSD in Part I and Article 6 in Part II). Part III of the document was the application information utilized for both permitting programs.

   Based on the new regulatory requirement in 2008 in the preceding paragraph, there was not an approved boilerplate for that action. The conditions generated during reviews previous to 2008 were separated during the 2008 review. In that permit, the conditions were mirrored in the sections for each of the permitting programs, and the citations were updated to the appropriate regulatory authority in each program.

   In order to remain faithful to the APS permit history, the current permit action retains separate PSD and Article 6 section but is reorganized as follows:

   Introduction
   Part I – Prevention of Significant Deterioration Specific Conditions
   Part II – Minor New Source Review Specific Conditions
   Part III – Source Wide Conditions.
   Part IV – Document List.

B. The wording of the general conditions in the draft permit matches the currently approved boilerplate language.

C. In accordance with former practice, Conditions 58 and 119 (severability), 59 and 120 (impact of air permit on approval by other media authorities), and 60 and 121 (confidentiality) as shown in the 2008 permit were included in the earlier versions of the permit for the information on the owner/operator. Since these do not form accessible applicable requirements, in accordance with currently approved boilerplate these conditions are no longer included in the draft permit.

VIII. Compliance Demonstration

Compliance with the primary boiler lb/hr emission limits will be demonstrated by stack testing of Total PM, Filterable PM, Total PM10, Filterable PM10, Total PM2.5, SO2, NOx, CO, and VOC. Compliance with the annual limits (non-CEMS) will be demonstrated monthly using the lb/hr emission rate and the hours of operation.

Compliance with the primary boiler lb/MMBtu emission limits will be demonstrated by CEM data for SO2, NOx, and CO.

Records shall be maintained to demonstrate compliance with the permit limits including (1) the biomass annual throughput limit, (2) the primary boiler annual hours of operation, (3) the primary boiler actual firing rate, and (4) the primary boiler daily[29] and annual heat input.

In the current draft permit, recordkeeping requirements for emission units other than the primary boilers and the biomass handling system are gleaned from APS's current Title V permit. This has been done to replace the generic wording of the recordkeeping condition from 1990.

IX. Title V Review - 9 VAC 5 Chapter 80, Part II, Article 1

APS has a Title V permit with an effective date 1/1/09. In accordance with 9 VAC 5-80-80 where an existing Title V permit would prohibit such operation, the owner must obtain a permit revision before commencing operation. Since the current Title V permit limits the CO emissions to less than the allowable emission rates in the current draft permit, Dominion must apply for and receive a revised Title V permit before commencing operation of APS as a biomass-fired facility.

X. Other Considerations

A. The Form 7 in the May 2011 permit application included two engines: (1) an emergency diesel feedwater pump, and (2) a diesel firewater pump.[30] Applicable requirements for the emergency feedwater pump and the firewater pump are included in the former NSR permit[31]. The current biomass conversion project does not include any changes related to engines.

B. The requirement to pave all facility access roads has been an applicable requirement since the initial permit for the site[32]. The requirement to control fugitive dust from these roads is added as part of the current biomass conversion project since such control is used in the permit application calculations demonstrating PSD applicability[33]. (i.e., former permit conditions 17 & 76)

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[29] NSPS Db at 60.49b(d)(1) requires records of both daily and annual "…amounts of each fuel combusted…"
[30] In their 12/1/11 email Labrie to Berkeley Dominion stated that there is not an emergency generator at APS.
[31] i.e., permit dated 1/30/08
[32] i.e., permit dated 2/21/90
[33] See application Appendix B, Sheet 6

C. Definition of "biomass:" 40 CFR 241.2 essentially defines "Clean Cellulosic Biomass," as the following family of 7 types of material unless they have been discarded:

1 forest-derived biomass (*e.g.*, green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials),
2 wood collected from forest fire clearance activities,
3 trees and clean wood found in disaster debris,
4 clean biomass from land clearing operations,
5 corn stover and other biomass crops used specifically for energy production (*e.g.*, energy cane, other fast growing grasses),
6 bagasse and other crop residues (*e.g*., peanut shells), and
7 clean construction and demolition wood.

The current draft permit identifies the approved fuel in accordance with the 40 CFR 241.2.[34] The typical boilerplate language that excludes, "…any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates", is made even more general by 40 CFR 241.2's provision that, "Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials."

D. List of miscellaneous permit language changes from 2008 version
(KEY to condition number references in this section: "former conditions" are the versions shown in the 2008 permit. The first condition number is located in the PSD section of that former permit and the second condition number is located in the Article 6 section of that former permit.)

1. PM Air Pollution Control Device (APCD) specification (former conditions 4&63)
   - It is noted that the former conditions' control efficiency value is a "rating" and that rated value (99.9%) is not changed.
   - Acid gas attack at low temperatures (e.g., during startup) is expected to be detrimental to APCD components. Therefore, consistent with 2008 permit and current practice, this condition allows bypass of the fabric filter during such conditions.
   - The description of startup fuels as "non-coal" is no longer germane and is deleted.
   - It is noted that the current project is not subject to BACT review for particulate[35].

2. SO2 APCD former conditions 7&66
   - The 2008 permit contained limitations for SO2 based on the combustion of coal. The 2008 requirements are 0.187 lb/MMBTU, 70.8 lb/hr, and flue gas

[34] Items 5, "other biomass crops," and 6, "other crop residues," are not part of the scope of fuels that Dominion sought approval to burn. Due to the inherent challenges of determining when such materials are "discarded" Item 7, "construction and demolition wood" is not considered part of the approved fuel currently.
[35] i.e., FPM, TPM, FPM10, TPM10, and TPM2.5
http://ecmiis/ECM/ViewDocument.aspx?ViewDocumentMode=DocContent&DocId={A8F5FDE0-DD24-4C6E-80B4-1242DDD735B7}

desulfurization with a 92% control efficiency. This switch to biomass reduces the available sulfur (i.e., ~ 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 0.013 lb/MMBtu and 4.9 lb/hr) are appropriate.

- It is noted that the current project is not subject to BACT review for SO2.

3. NOx APCD former (Conditions 8&67)
   - The former permit included the requirement to have a "continuous ***coal*** feed system" as part of the NOx air pollution control approach; along with staged combustion air and SNCR. References to coal are no longer germane after the biomass conversion of APS. Consistent with 9VAC 5-50-20E, the general duty requirement to operate and maintain in a manner consistent with minimizing emissions, these conditions are altered to require "continuous ***biomass*** feed systems."
   - It is noted that the current project is not subject to BACT review for NOx.

4. Fugitive emissions (Conditions 12&71)
   - Reference to the coal crusher is no longer germane and is removed

5. Combined primary and auxiliary boiler annual emission limits (former Conditions 24&84)
   - The former permit included combined primary and auxiliary boiler annual emissions limits. There are no changes to the auxiliary boiler as part of the current biomass project. The revised values for these combined limits are calculated by subtracting out two times the pollutant specific annual emission limit[36] which is included in former Condition 22 and adding back two times the revised (i.e., biomass) annual emission limit.[37]
   - The emission limit note, "♦ The maximum input ratio for wood and coal is to be established after in-stack testing", is no longer germane and is deleted.

6. Material handling emissions (former Conditions 26&86, and current Conditions 16&67, 26&76, biomass handling)
   - Quantitative assessment of short term emissions from much of the former material handling systems (e.g., ash handling, storage piles, and road traffic) is difficult, if possible at all. Therefore, the current draft retains annual emission limits for inventory purposes and relies on more qualitative mechanisms required by the permit to insure proper operation on a short term basis (e.g.,

[36] The annual limits in the former Condition 22 were stated on a "per (primary coal) boiler" basis.
[37] Note: Former condition 24 annual limits for auxiliary boiler operation are limited to 360 hr/yr. The resulting aux boiler contributions (in tons/yr) are: PM=1.0, PM10=0.8, SO2=7.8, NOx=5.0, CO=2.1, and VOC=1.0)

general-duty site wide fugitive dust and emission controls, road sweeping, and opacity limits).

- It should be noted that as used in the current draft permit the term "biomass" subsumes the previously approved fuels wood chips and wood dust (e.g., in condition 16 & 67 the total amount of material processed annually through the biomass handling system is 785,480 tons/yr; not 785,480 tons/yr of biomass and some additional amount of wood dust).

7. NSPS Kb applicability to 100,000 gallon distillate oil tank (former Conditions 50&110)
   - With changes to NSPS Kb applicability triggers, the distillate oil tank is no longer subject to NSPS Kb and so the conditions incorporating that NSPS by reference are removed from the current draft permit. Regardless, of applicability, Virginia's Regulations require a facility to maintain records demonstrating continued exempt status from a provision of the Regulations. APS must continue to maintain records sufficient to demonstrate that Kb does not apply.

XI. Public Participation

A. Public Information Briefing

In accordance with Section 9 VAC 5-80-1775.D of the Regulations, an informational briefing was held by the applicant 9/13/11, at the Altavista "Train Station" building. There were approximately 8 citizens in attendance, along with approximately 3 representatives of the source, and 2 representatives of DEQ.

B. Public Hearing

In accordance with 9 VAC 5-80-1775.F.6, BRRO will hold a public hearing to accept comments on the air quality impact of the proposed source, alternatives to the source, the control technology required, and other appropriate considerations. The public hearing is scheduled for 4/16/12, beginning at 7 p.m., at the Altavista Town Council Chambers at 510 7TH Street, Altavista, Virginia.

C. Documents Concerning Public Comment Period

Public versions of the documents used in development of the draft permit are available for review the Blue Ridge Regional Office throughout the public comment period.

XII. Notifications of Other Government Agencies

A. Local Zoning

Because the proposed power station constitutes a major modified source subject to air permitting regulations, a local governing body notification form is required in accordance with Department policy and section 10.1-1321.1 of the Code of Virginia. On 5/17/11, the Town of Altavista Assistant Town Manager certified that the proposed facility is fully consistent with all applicable local ordinances.

B. Federal agencies

1. EPA

   In accordance with 9 VAC 5-80-1765, there are specific notification requirements to advise EPA of sources impacting federal class I areas. Accordingly, a copy of the permit application and the initial letter of determination are being provided to EPA. EPA will be provided with a copy of the draft permit and will be notified of the public comment period and the final determination on permit issuance.

2. Federal Land Managers

   The facility to be constructed is located approximately 51 km from the James River Face Wilderness Area and 109 km from the SNP. In accordance with agreements between DEQ, the SNP, and the Jefferson National Forest, FLMs request review of all PSD permits within the state, regardless of distance from the designated Class I areas. On 5/11/12, a "pre-application" conference call was held with the FLMs. Responding to the conference call discussions, the FLMs[38] indicated that they would not be requesting AQRV analyses but that they would like to receive a copy of the draft permit when it is noticed to the public.

XIII. Recommendations

It is recommended that the current draft be made available for public comment.

Attachments

Attachment A: Article 6 applicability R3.xlsx)
Attachment B: Article 8 applicability SO2, CO, NOx, Pb.xlsx
Attachment C: Deferred GHG R2.xlsx
Attachment D: Article 8 applicability PMs, VOC, H2SO4, F.xlsx

[38] Park Service: D. Shepherd in 5/13/11 email, and Forest Service: M. Pitrolo in 5/19/11email http://ecmiis/ECM/ViewDocument.aspx?ViewDocumentMode=DocContent&DocId={A8F5FDE0-DD24-4C6E-80B4-1242DDD735B7}