VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office

INTRA-AGENCY MEMORANDUM

Permit Writer	Berkeley				
Memo To	Air Permit File	**Date**	April 16, 2015		
Facility Name	Virginia Electric & Power Company – Altavista Power Station				
Registration Number	30859 **CEDS** 24				
County-Plant I.D.	031-00156				
Decimal Coordinates	37.11830	**Latitude**	-79.27470	**Longitude**	
Elevation (feet)	600				
Distance to Class I Areas	109	**SNP (km)**	51	**JRF (km)**	
FLM Notification (Y/N)	NA[1]	**Required if less than 10K (minor), 100K (state major)**			
NET Classification (A, SM, B)	A	**Before permit action**	No change	**After permit action**	
Title V Major Pollutants	NOx & CO	**Before permit action**	No change	**After permit action**	
PSD Major Source (Y/N)	Y	**Before permit action**	No change	**After permit action**	
PSD Major Pollutants	NOx & CO	**Before permit action**	No change	**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 4/9/14, BRRO received an application dated 4/2/14 requesting various adjustments to the NSR permit dated 5/22/12 by which the station was converted from a coal, wood dust, and wood chip fired facility to one whose primary fuel is biomass.

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

As mentioned above, in 2012 APS received a permit to change the two primary boilers at the facility to biomass units. Dominion's operating experience at APS now indicates that several changes to that permit are needed because the magnitude of biomass fuel variability (i.e., both moisture content and species mix) is greater than anticipated. This variability results in less stable combustion. The principle pollutant impacted by this variability is carbon monoxide (CO) and the central focus of the requested changes is the short term limit on CO in units of pounds per hour (lb_{CO}/hr).

The requested permit changes may be grouped as follows:

<u>Principle Changes</u>

(1) Remove the lb_{CO}/hr statement of the short term limit (the lb_{CO}/MMBtu statement will be retained as permitted in 2012);
(2) Extend the approved use of natural gas and No. 2 fuel oil from startup only to add use during shutdown and for flame stabilization;

[1] The FLMs were notified of the current activity at APS and reportedly they were not interested in a pre-application meeting (10/15/14 email Kiss to Berkeley).

(3) Allow the use of a "diluent cap" (i.e., a floor value of CO2 of 5%) in CEM emission calculations in order to avoid a generally recognized arithmetic tendency to over-represent emissions during startup and shutdown (i.e., division by "nearly" zero); and
(4) Rework the load apportionment to each of the two individual primary boilers from an exhaust volume based approach to a heat input based approach.
   (a) As a consequence of changing to the heat input approach, replace the current "per boiler" based limit on capacity with a combined capacity for the fleet of two, and
   (b) Update the recordkeeping requirements to match this change in statement of the capacity.

Opportune Changes (i.e., other issues that may be addressed while the permit is "open" to make the principle changes)
(5) Remove all references to the Auxiliary Boiler (a mutual shutdown agreement is being implemented for this unit);
(6) Make several descriptive changes (e.g., change the quantity of wet ash handling systems per boiler from 3 to 1) to reflect the as-built equipment arrangements; and
(7) Notify DEQ of possible future changes to increase the capacity of the NOx air pollution control device (SNCR) system (e.g., increase tank size for reagent)

The acceptability of each of the requested changes is discussed below; with the specifics of Article 6 and Article 8 permit applicability discussed later in Sections III.A and III.B, respectively.

Change 1: Remove lb_{CO}/hr limit
The 2012 review determined that (a) control of CO emissions was subject to Article 8 BACT review, (b) that Good Combustion Practices (GCP) were BACT for the biomass conversion project, and (c) that APS's proposed 0.3 lb_{CO}/MMBtu on a 30-day rolling average basis was as good or better than the controls for similar facilities as shown in the RACT/BACT/LAER Clearinghouse (RBLC).

Dominion maintains that APS is applying GCP by continuously monitoring emissions and making boiler adjustments as expeditiously as possible. Currently manual adjustments are made in accordance with best practices as directed by the manufacturer and include fine-tuning the traveling grate speed, altering the combustion air distribution, and regulating the fuel feed rates. On-going improvement of boiler controls is fostered by regular weekly conference calls among the 3 sister biomass plants, installation of a "smart" control system to enable future automatic combustion process adjustment, and installation of a system to monitor in real time the moisture content as the fuel is conveyed to the boiler. DEQ does not dispute these practices as GCP.

The lb_{CO}/hr statement of the short term limit was included in the 2012 permit to support the required modeling demonstration of compliance with the 1-hour and 8-hours NAAQS for CO. Dominion argues, and DEQ's modeling section concurs, that since the modeled CO impact for APS is much less that the Significant Impact Level (SIL)[2] and since the SIL is 5% of the NAAQS, the lb/hr limit is not necessary for insurance of compliance with the NAAQS.

For these reasons, it is considered acceptable to remove the lb_{CO}/hr statement of the short term limit. It is noted that both the lb_{CO}/MMBtu and ton_{CO}/year limits from the 2012 review remain unchanged.

[2] i.e., worst case approximately 14% of the SIL. (See 12/2/13 email Kiss to Berkeley et al)

Change 2: Extend the use of "startup" fuels
As part of the effort to mitigate the effects of biomass variability, APS has requested that the use of natural gas and No. 2 fuel oil, which are currently limited to use as boiler startup fuels[3], be extended to (1) use during the boiler shutdown sequence to make that process more orderly/manageable, and (2) use for flame stabilization during transient periods to prevent flame loss.

As described in Sections III.A and III.B below, this change is not subject to review under either Article 6 or 8. Also, as explained as part of the change 4 (rework of apportionment) discussion, APS will employ F-factors[4] to demonstrate compliance with the pollutant-by-pollutant emission limits per boiler. Part 75 [5] allows the use of the "worst-case" F-factor; which is the highest factor for any fuel fired in a unit in a unit operating hour. The F_C-factor[6] for Wood-Bark is 1920, for Oil 1420, and for natural gas 1040 scf/MMBtu. Therefore, Dominion has proposed to use the Wood-Bark factor for any hours when multiple fuels are combusted. Therefore it is considered acceptable to extend the use of natural gas and fuel oil as requested.

Change 3: Allow the use of a "diluents cap"
Conditions in the 2012 permit require APS to follow data reduction and quality assurance procedures on the CEMS in accordance with NSPS Db.[7] Language has been added to these CEM conditions that allows Dominion to submit for written approval alternate monitoring procedures (e.g., use a diluent cap).

Change 4: Rework load apportionment to heat input based approach
In 2008 APS received a permit amendment which was aimed, in part, at addressing spikes in CO emissions during normal operation as shown by a CEMS that the station had installed for its own purposes. That amendment increased the averaging time for the short term CO limit to a 30-day average.[8] To show compliance with that new statement of the limit on a per boiler basis, APS proposed to apportion the exhaust gas flow in the common stack for the two units based on data obtained from a flow monitor that was already in place for Title IV purposes.[9]

Now APS recognizes that that method of apportionment breaks down when one boiler (say PB1) is operating its induced draft fan while combusting little or no fuel (e.g., if the boiler is being cooled down so internal maintenance may be performed on it) and the other boiler (PB2) is operating normally. In such a situation the pollutant concentration as measured by the CEMS located in the PB2 breaching is used with an artificially high flow rate in the common stack (PB1 + PB2) and may well indicate reportable excess emissions for PB2 when in fact that high value is the result of a misrepresentative calculation. Therefore, as shown in their letter dated 8/5/14, APS is now proposing to use Equation F-15 from Part 75 Appendix F to calculate the total heat input (HI) for both boilers as a function of the measured common stack exhaust flow rate, the carbon-based F-

[3] E.g., see 2012 Condition 48
[4] Per Part 60, Appendix A, Method 19 and *F-Factor* "…is the ratio of the gas volume of products of combustion to the heat content of a fuel."
[5] Part 75, Appendix F, Section 3.3.6.5
[6] Carbon (based) F-factor
[7] See 2012 Conditions 41 (CO CEM) and 39 (SO2 and NOx CEMS)
[8] In accordance with historic practice the prior lb/hr limit would have effectively been a 3-hour average based on stack testing.
[9] Title IV ≡ Acid Rain Operating Permits

factor, and the common stack measured CO_2 concentration.[10] This total HI is then apportioned to each individual boiler using Part 75's equation 21-b as a function of the ratio of the boiler-specific operating time to the total common stack operating time and the ratio of the individual boiler steam load to the combined steam load for the two boilers. In this way the former misrepresentation of emissions from a boiler firing little or no fuel is eliminated. This revised apportioning approach, using in-place monitor data and individual boiler steaming times and loads in accordance with Part 75 procedures, is considered an acceptable revision to compliance demonstration at APS.

However, as shown in the preceding paragraph, the applicable requirement to apportion monitored data to the individual boilers is NOT eliminated but is rather reworked to correct a formerly flawed approach to match Dominion's currently suggested approach. Therefore, the 2012 Condition 42 is not removed as requested in the 4/2/14 letter but is reworded to reflect that suggested approach. Also, language from Part 60, Appendix F[11] has been added to the portion of Condition 42 that addresses timing such that the RATA may be postponed if neither primary boiler is operating.

4a: Replace the current "per boiler" based limit on capacity with a combined capacity for the fleet of two

As presented in the permit application, including its amendments[12], the hourly, per primary boiler emissions limits for SO_2, CO, NOx, and lead in the 2012 permit were calculated as the product of each pollutant-specific lb/MMBtu emission rate and a stated maximum hourly heat input of 394 MMBtu/hr. Therefore, after a great deal on discussion, in order to make these hourly emission limits enforceable as a practical matter, APS accepted conditions in that 2012 permit specifying the maximum allowable hourly heat input rate on a per primary boiler basis[13].

As discussed above for Change 4, with its 8/5/14 letter APS has now shown how compliance with these per boiler hourly limits may be explicitly demonstrated on an ongoing basis without relying on a per boiler heat input rating. Therefore, as requested, the per boiler heat input specification (394 MMBtu/hr/boiler) is replaced with a combined heat input for both primary boilers (788 MMBtu/hr); with compliance shown by Equation F-15 from Part 75 Appendix F to calculate the total heat input (HI) for both boilers.

4b: Update the recordkeeping requirements to match the change approved in 4a

As discussed above (i.e., Change 4a) Dominion's 4/2/14 letter requests and BRRO has accepted that the hourly capacity of the two primary boilers be limited as a combined value (i.e., 788 MMBtu/hr) rather than the per boiler value currently shown in the 2012 permit (i.e., 394 MMBtu/hr/boiler). The language of 2012 recordkeeping condition for the hourly limit (i.e., 2012 C115b) is revised to match the combined limit as requested by Dominion. Also, as requested, the language of 2012 Condition C115c is updated to insure that the annual heat input is for both primary boilers combined.

[10] Per 9/8/14 email Gates to Berkeley: The CO_2 concentration in the common stack is directly measured by a CEM installed for Title IV purposes
[11] Part 60, Appendix F, section 5 (Data Accuracy Assessment) paragraph 5.1.4
[12] See 2012 file calculations: Article 8 applicability SO2-CO-NOx-Pb.xlsx
[13] See Conditions 18 (PSD section) and 71 (Article 6 section) of the 5/22/12 NSR permit

Change 5: Remove all references to the Auxiliary Boiler

The 4/2/14 letter says that APS plans to disable[14] and abandon in place the auxiliary boiler (EU 003). As requested all references to the auxiliary boiler have been removed from the permit. The process of making a mutually agreed upon shutdown determination has been begun and will be completed prior to executing this permit amendment.

Change 6: Make several requested descriptive changes

6a. Change number of wet ash handling systems from 3 to 1 in the equipment list

The requested change in quantity is made in the equipment list (2012 C1) and language identifying the bottom ash handling system as that remaining wet ash system has been added[15].

6b. Change description of biomass handling system in the equipment list to add its installed "sizing function"

The requested change in the equipment list (2012 C1) is made as follows:

- 2012: biomass handling system (unloading, conveyor feed system, storage pile…
- Current: biomass handling system (unloading, conveyor feed **and sizing** system**s**, storage pile…

6c. Remove the second sentence in 2012 C14 since the equipment was not installed

In coordination with the changes described in 6a, the requested change was made since neither the wet ash handling system serving the boiler generator bank or the one serving the mechanical collector were installed.

6d. Revise language of 2012 C37 to clarify locations of various CEMS.

As part of their response dated 6/20/14 to the ILOD, APS provided suggested language that would satisfy their request for clarity. The provided language was accepted as submitted.

Attachment A to this analysis is a sketch that shows locations as provided in the 6/20/14 letter as well as:

- the location of flow monitor (installed for Title IV purposes),
- the CO2 monitor (installed for Title IV purposes[16]), and
- the per boiler CO monitors.

Change 7: Notify DEQ of possible future changes in NOx air pollution control device system

Dominion is studying the value of making future changes to the SNCR equipment and/or process at APS. Since the scope of any such changes is not yet specified, no applicability determination(s) are being made as part of this current analysis.

[14] Blank off fuel lines in a visible location and disconnect the power the control panel for the boiler

[15] In the 1/28/15 email Gates to Berkeley: Dominion explained that the control system referred to in 2012 C13 is not one of the three **wet** ash handling system (i.e., the C13 system moistens the material). It is also noted that C13 has been part of the site's permit since at least 2008

[16] via 9/8/14 email

III. Regulatory Review

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

The provisions of Article 6[17] apply throughout Virginia to (i) the construction of any new stationary source, (ii) the construction of any project (which includes the affected emissions units), and (iii) the reduction of any stack outlet elevation at any stationary source.

Article 6 permitting is not applicable because the requested change does not meet the criteria stated above because, as stated in 9VAC5-80-1110 C, a project requires an affected emissions unit (added, modified, or replacement unit). A modified unit must have a physical or operational change that will increase the uncontrolled emission rate[18&19]. There are no affected emissions units with this request; Article 6 does not apply.

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 9VAC5-80-1290.

B. 9 VAC 5 Chapter 80, Part II, Article 8 and Article 9 – PSD Major New Source Review and Non-Attainment Major New Source Review

Campbell County is a PSD area for all pollutants as designated in 9VAC5-20-205.

APS is a PSD major source. The provisions of PSD apply to any project at an existing major stationary source[20], and no owner shall begin actual construction of any major modification at an existing major source without first obtaining a permit[21]. A project is a major modification if it causes two types of emission increases: a significant emissions increase (SEI) and a significant net emission increase (SNEI). The procedure for calculating whether a SEI will occur depends on the type of emissions units being modified. For the current project at APS the emissions test contained in 9VAC5-1605 G.4 has been used since this project involves only new emissions units[22]. This test utilizes the baseline actual emissions (BAE) to future potential emissions (PTE) test for each new unit.

Step 1 of determining if a major modification will occur is to sum all of the emission increases associated with the project for each pollutant. If the result for a pollutant is less than the

[17] Language is paraphrased from 9VAC5-80-1100.
[18] This information is paraphrased from two definitions: "modification" and "project".
[19] The current "operational change" is to extend the use of NG and No. 2 fuel oil from fuels allowed during startup only to fuels used during startup, shutdown, and during normal operation (for flame stabilization). Before the current project NG combustion was allowed 8,760 hr/yr and No.2 fuel combustion was limited to 60,000 gal/yr. Neither of these two allowable throughputs is being increased as part of the current project; therefore the NUE = CUE, and for Article 6 applicability purposes, the primary boilers are not being modified.
[20] 9VAC5-80-1605 (Article 8 Applicability), and per 9VAC5-80-1615 (Article 8 Definitions) the definition of a "project" includes a change in method of operation.
[21] 9VAC5-80-1625 (Article 8 General)
[22] Per 9VAC5-80-1615 a "*new emissions unit*" is any emissions unit that is (or will be) newly constructed **AND** that has existed for less than two years from the date such emissions unit first operated," and "*construction*" means any physical change or change in the method of operation (including…modification of an emission unit) that would result in a change in emissions." The primary boilers at APS first operated as modified-to-fire-biomass units (a project that resulted in a change in emissions) in September 2013 (i.e., currently less than two years ago).

significant emissions rate, then there is not a significant increase and a major modification has not occurred for that pollutant. For the current project at APS, the BAE is equal to the PTE for all pollutants[23]. Therefore, the emission increases for these pollutants is zero (which is less than the SEI for each) and PSD review does not apply to this current project.

However, this project does involve, for example, significant changes to existing PSD monitoring and recordkeeping requirements and therefore fits the criteria for use of significant amendment procedures per 9VAC5-80-1955.

Greenhouse Gases (9 VAC 5 Chapters 80 and 85)
As discussed previously in this section, the project is NOT a major modification subject to PSD review. Therefore, greenhouse gases (GHG) need not be considered for regulation as a "regulated NSR pollutant".[24]

C. 9 VAC 5 Chapter 80, Part II, Article 5 – State Operating Permit (SOP)
Not applicable.

D. 9 VAC 5 Chapter 50, Part II, Article 5 – NSPS
Prior to the 2012 conversion to biomass, the primary boilers at APS were subject to NSPS Da. In their letter dated 2/21/12, Region III concluded that the primary boilers were no longer subject to NSPS Subpart Da since biomass (wood) is not a fossil fuel but that they are subject to NSPS Db. The Subpart Db pollutants to which standards apply are PM, NOx, and SO2.[25]

In accordance with 40CFR60.42Db(k)(2) the primary boilers at APS are exempt from $S0_2$ emission limits[26] and by extension from SO_2 testing and monitoring provisions. The reporting requirements for 40CFR60.49b(r)(1) do apply.[27]

NSPS Db includes standards for PM for units with a capacity greater than 250MMBtu/hr that combust over 30 percent wood (by heat input).[28] The primary boilers at APS are above these

[23] Per 9VAC5-80-1615 "*Baseline actual emissions*" means the rate of emissions, in tons per year… (paragraph c) For a new emissions unit, the baseline actual emissions for the purposes of determining the emission increase that will result from **initial** construction (e.g. again, which by definition includes modification of that unit) and operation of such unit equal zero; **and thereafter, for all other purposes**, shall equal the unit's PTE. For the primary boilers at APS, the **initial** construction of the biomass modification occurred in 2012, and this current project is considered subsequent to that construction.

[24] On June 23, 2014, the United States Supreme Court issued a decision on EPA's GHG Tailoring Rule. In summary, the Supreme Court said that EPA may not treat GHGs as an air pollutant for purposes of determining if a source is major for PSD and/or Title V permitting, but sources that trigger PSD for a pollutant other than GHGs should still apply Best Available Control Technology (BACT) to the GHG emissions. APG-311 is Virginia's guidance implementing this approach.

[25] Region III's letter did not address whether the pre or post 2/28/05 NSPS Db standards apply to the converted units at APS. Since both the physical conversion and Region III determination about it were made well after 2005, the post 2/28/05 provisions are considered relevant for the discussion in this section.

[26] 40CFR60.42Db(k)(2) says "Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO2 emission rate of … 0.32 lb/MMBtu… heat input or less are exempt from the SO2 emissions limit…" The permitted S02 emissions from the biomass are 0.0125 lb/MMBtu. APS fires biomass, natural gas and distillate oil but its permit includes a maximum distillate oil sulfur content (0.3 wt %) so that the approved fuel meets the definition of "very low sulfur oil"

[27] Submit report certifying that only fuels known to contain insignificant amounts of sulfur were combusted during the reporting period.

[28] 60.43b(h)(4)

thresholds but the BACT based emission limitation (0.019 lb/MMBtu[29]) is more restrictive than the NSPS Db based emission limitation (0.085 lb/MMBtu), so the NSPS PM standard applies (albeit streamlined by the BACT based limit).

NSPS Db standards for NOx apply unless a federally enforceable annual capacity factor of 10% or less for listed fuels is in place. The listed fuels include any combination of natural gas and oil. At APS the annual capacity factor is currently greater than 10%[30]. Therefore, while the BACT based emission limitation (0.135 lb/MMBtu, 30-day average) is more restrictive than the NPSP Db based emission limitation (0.2 lb/MMBtu, 30-day average), the NOx standards apply (albeit streamlined by the BACT based limit).

The current Title V permit includes the relevant provisions for NSPS Db.[31] (See also Section X, Title V Review, below)

E. 9 VAC 5 Chapter 60, Part II, Article 1 – NESHAPS
There are no applicable NESHAPS (40 CFR Part 61) standards.

F. 9 VAC 5 Chapter 60, Part II, Article 2 – MACT
APS is a major source of hazardous air pollutants (HAPs). The biomass boilers are subject to 40CFR63 Subpart DDDDD (Boiler MACT), which was amended on 1/31/13. The legal status of that MACT is currently under reconsideration by EPA[32]; however, the boilers are in the existing source category (i.e., they were constructed before the proposal date). The 2012 permit application (Appendix B, Sheet 4) shows the combined emission rates for individual HAP and total HAPs for both boilers. The applicable requirements after reconsideration resolution will be incorporated into the Title V permit.

G. State Only Enforceable (SOE) Requirements (9 VAC 5-80-1120 F)
None.[33]

IV. Best Available Control Technology Review (BACT)

Generally, permit amendments are not subject to BACT review for either Article 6 or Article 8. The impact of the current project on the 2012 BACT determination is described in Section II (Change 1) above.

V. Combination of Permit Program Requirements

Neither the provisions of 9VAC5-80-1255 or 9VAC5-80-1915 apply because this current permit amendment does not change any formerly independent permit approvals into a single permit document.

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[29] Because of the test methods specified in Db the regulated NSPS pollutant is filterable PM

[30] Current "startup fuels"= NG & DO; No NG limit; DO limited to 60,000 gal/yr therefore the annual capacity = 989,400 MMBtu/yr. 10% of primary boiler potential capacity at steady state = 664,008 MMBtu/yr (NG burner = 56 MMBtu/hr per boiler)

[31] See Statement of Basis for the Title V Significant Modification dated January 15, 2013 for additional details

[32] On 1/21/15, EPA announced reconsideration of limited number provisions in the amendment. However, the status of the rule itself does not alter the outcome that the APS boilers are subject to Subpart DDDDD.

[33] See analysis for 2012 NSR permit for additional discussion regarding coordination of state toxics rules and the boiler MACT

VI. Summary of Actual Emissions Increase

As shown in Section III above the current project does not increase either the uncontrolled emissions (Article 6) or the PTE (Article 8).

VII. Dispersion Modeling

A. Criteria Pollutants

As shown in Section IIIB above, the changes in allowable emissions for all criteria pollutants from this project are less than their respective significant emission rate as shown in 9VAC5-80-1615C. Therefore, generally no modeling of any criteria pollutant is required. Specifically, based on data submitted to DEQ's modeling section, no additional CO modeling is needed.[34]

B. Toxic Pollutants

Not applicable. As mentioned above, the boilers at APS are subject to the major source boiler MACT. A facility subject to a MACT is exempted from review under the State Toxics regulations (9VAC5-60-300 C), including any modeling requirements.

VIII. Boilerplate Deviations

The boilerplate deviations have not changed from those described in the analysis for the 2012 permit action

IX. Compliance Demonstration

Except as described in Section II (Changes 3 and 4) above, the compliance demonstration provisions have not changed from those described in the analysis for the 2012 permit action

X. Title V Review – 9 VAC 5 Chapter 80 Part II Article 1

The facility is a Title V major source due to a potential to emit (PTE) greater than 100 tons per year for at least one regulated pollutant.[35] Until a complete application for a Title V permit modification is received and appropriately processed[36] , certain provisions of the current NSR significant amendment are beyond provisions contained in the Title V permit dated 1/15/13.[37]

XI. Other Considerations

On 2/18/15 BRRO received comments dated 2/13/15 on two conditions in the draft permit.[38]

The first comment was a correction to the previously submitted location description for the SO2 CEMS as shown in Conditions 31 and 77. The 2/13/15 comments included a revised CEM location "sketch."

[34] See 11/17/14 email Kiss to A. Gates. It is noted that the indication is that no impact from the application of a diluent cap was included in the data submitted by Dominion.
[35] E.g., Total PM, NOx, and CO.
[36] The "appropriately processed" language is used to note that, for example, there is a difference between when (1) a Title V Significant Modification action becomes effective (i.e., upon permit signature) and when (2) the changes applied for under the Title V Administrative Amendment provisions may be implemented (i.e., provisionally upon receipt of a complete application (9VAC5-80-200 A5 & B4)).
[37] E.g., the 1/15/13 Title V permit has (1) NSPS Db reduction and quality assurance procedures (which do not allow the application of a diluent cap) for the NOx, SO2, and CO CEMS; and (2) the RATA must be performed at least once every four consecutive calendar quarters
[38] Draft = 30856 Ptb R2.5 CLEAN.docx

The second condition commented on was Condition 35[39]. The principal focus of that condition is the exhaust gas flow monitor located in the common stack for the two primary boilers and how this single flow may be used to demonstrate compliance with the permitted "per boiler" emission limits. As shown above in the discussion of Change 4 (Rework load apportionment to heat input based approach), in their 8/5/14 letter APS presented mechanics that may be used for this compliance demonstration and Dominion's 2/13/15 suggested language revisions are used in large part to capture those mechanics in the permit document.[40]

XII. Public Participation

In accordance with 9VAC5-80-1955C the provisions of 9VAC5-80-1775 apply to Article 8 significant amendments. Also, as allowed by 9VAC5-80-1290C, the public comment and public hearing provisions of 9VAC5-80-1170 are applied.

A. **Public Information Briefing**
In accordance with Section 9VAC5-80-1775D of the Regulations, an informational briefing was held by the applicant on 6/24/14 in the Altavista Town Council Chambers ("Train Station" building). There were no citizens, 5 representatives of the source, and 1 representative of DEQ in attendance.

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 3/31/15, beginning at 6:30 p.m., at the Altavista Town Council Chambers at 510 7^TH^ 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.

D. **Public Comments**
The public comment period ended on April 15, 2015 with no comments received.

XIII. Notifications of Other Government Agencies

A. Local Zoning
Because the proposed project does not constitute a major modification of the source, no local governing body notification form is required in accordance with section 10.1-1321.1 of the Code of Virginia.

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[39] The parallel in the Article 6 section of the permit is C81.

[40] The reason for the inclusion of the RATA-specific language in the 2008 PSD avoidance permit (for CO) is no longer required (i.e., in 2008 it was felt that since the PSD is a program based on annual emission rates, it was necessary to insure that the measurement device that showed the relevant threshold was not exceeded (i.e., the flowmeter) needed to be verified at least annually). With the 2012 permit, APS is no longer avoiding PSD for that pollutant.

B. Federal agencies

1. EPA

   In accordance with 9VAC5-80-1765, 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

   APS 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, these FLMs request review of all PSD permits within the state, regardless of distance from the designated Class I areas. On 10/15/14, BRRO received notification that none of the relevant FLMs would require a "pre-application" conference call for this project[41]. As a courtesy a copy draft permit package will be provided to the FLMs when it is noticed to the public.

XIV. Recommendations

Approval of the draft significant permit amendments is recommended.

Attachments

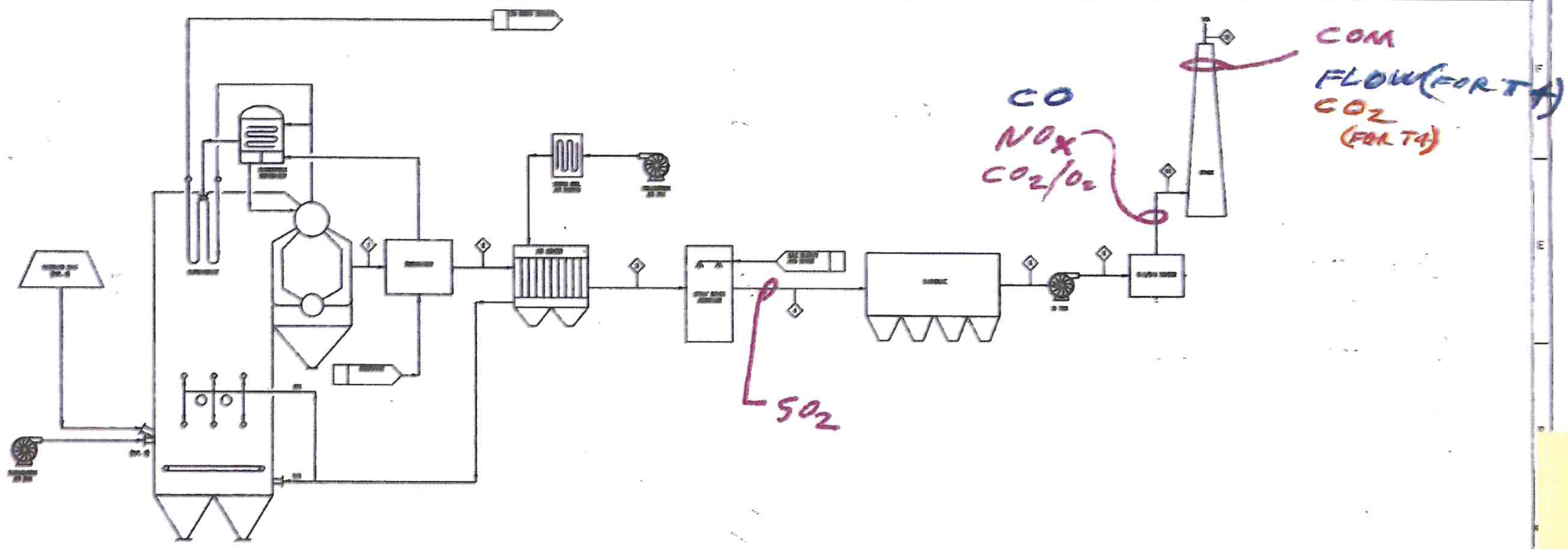
Attachment A: Sketch - Monitor locations

[41] See DEQ email dated 3/12/14: Kiss to NPS, USFS and FWS

→ 9/8/14 EMAIL

→ FOR MONITORS NOT ADDRESSED IN 6/20/14 LTR

CEMS PER 5/28/14 LTR



		1	2	3	4	5	6	7	8	9	10	11	12	13
Process Parameter / Point Description	Units	Generating Bank Outlet	Economizer Outlet	Air Heater Outlet	SDA Outlet	Baghouse Outlet	Gas to Gas HX Inlet (Shell Side)	Gas to Gas HX Outlet (Shell Side)	Reheater Burner Out / Catalyst Inlet	Catalyst Out	Gas to Gas HX Outlet (Tube side)	Stack	Reheat Burner Air	Reheat Burner Natural Gas
Mass Flow	lbs/hr	451,000	451,000	451,000	475,000	475,000	475,000	475,000	511,000	511,000	511,000	511,000	34,557	1,443
Volumetric Flow	ft³/min	264,000	209,000	171,000	140,000	140,000	140,000	228,000	265,000	265,000	179,000	179,000	7,660	8.89
Temperature	°F	869	594	401	190	190	190	600	699	699	321	321	80	68
Pressure	iwc	-2.3	-4.5	-6.1	-11.8	-17.8	14.1	10.6	8.1	6.1	0.5	0.0	16.6	46.6

DOMINION™

DOMINION ENGINEERING COMPANY

FOSSIL & HYDRO TECHNICAL SERVICES
RICHMOND, VIRGINIA

PROCESS FLOW DIAGRAM
BACT ANALYSIS OF CTO
ALTA VISTA/HOPWELL/SOUTHAMPTON
BIOMASS CONVERSION

REV	Description
1	REVISED TO INCLUDE DOMINION LOOP NUMBERS
0	ADDED CHUTE ISSUED FOR CONSTRUCTION
A	ISSUED FOR CUSTOMER REVIEW

DSGN	RMM	DSGN SUPV	DLF	DRAWING NUMBER	REV.
DRWN	LDW	DIGN SUPV	TJB	636010F01	A
CHKD	JHW	PROJ ENGR	RMM		
SUPV. ENGR.	RMM	SCALE:	NONE	UNLESS OTHERWISE NOTED	SH 1 OF 1