TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

Tampa Electric Company (TECO)
Post Office Box 111
Tampa, Florida 33601-0111

Representative: Karen Sheffield, General Manager, Big Bend Station

1.2 Reviewing and Process Schedule

09-12-07:	Received Notification of Change without Permit Revision
09-15-07	Advised TECO of possibility that permit is required
09-19-07:	Requested additional information (RAI) regarding project
10-11-07:	Received responses to RAI
10-12-07:	Advised TECO and consultant (ECT) that permit is required
10-22-07:	Received application for Units 3 and 4 stack and scrubber project
10-29-07:	Distributed Intent to Issue Air Construction Permit

2.0 FACILITY INFORMATION

2.1 Facility Location: Big Bend Station located at Wyandotte Road between Apollo Beach and North Ruskin, Hillsborough County.

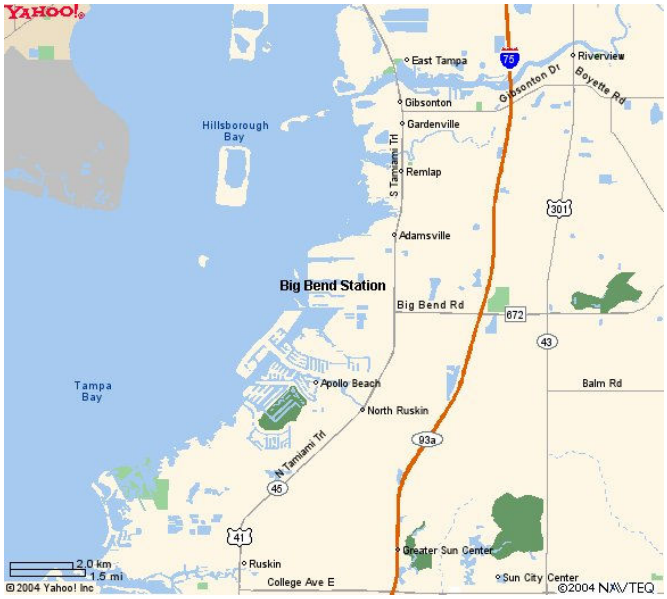

Figure 1. N. Ruskin, Apollo Beach and Big Bend

Figure 2. Big Bend Station

2.2 Standard Industrial Classification Code (SIC)

Major Group No.	49	Electric, Gas, and Sanitary Services
Group No.	491	Electric Services
Industry No.	4911	Electric Services

2.3 Existing Facility/Emission Unit Description
This facility is an electric utility.
This air construction permit will affect Steam Generators Nos. 3 and 4.

2.4 Regulatory Classification

The key regulatory provisions applicable to Stanton Units 1 and 2 are:

Title I, Part C, Clean Air Act (CAA): The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 Prevention of Significant Deterioration (PSD) Major Facility Categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a "major stationary source" of air pollution with respect to Rule 62-212.400, Florida Administrative Code (F.A.C.), Prevention of Significant Deterioration of Air Quality.

Title I, Section 111, CAA: Unit 4 is subject to Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) of the New Source Performance Standards in 40 Code of Federal Regulation (CFR) Part 60.

Title I, Section 112, CAA: The facility is a "Major Source" of hazardous air pollutants (HAP).

Title IV, CAA: The facility operates units subject to the Acid Rain provisions of the CAA.

Title V, CAA: The facility is a Title V or "Major Source of Air Pollution" in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

CAIR: The facility is subject to the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, Florida Administrative Code (FAC).

CAMR: The facility is subject to the Clean Air Mercury Rule (CAMR) set forth in Rule 62-296.480, F.A.C.

Siting: Unit 4 was originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C.

3.0 PERMITTING STATUS

Operation of the Big Bend Station is authorized by the Title V Operation Permit Revision 0570039-017-AV that has an effective date of January 1, 2005 and expires on December 31, 2009. The current permit includes the applicable requirements from federal and state regulations and construction permits. It also includes a Consent Final Judgment (CFJ, DEP vs. TECO) dated December 6, 1999 and a Consent Decree (CD, EPA vs. TECO)) dated February 29, 2000 and amended October 4, 2000. The CFJ and CD require

substantial progressive emission reductions from the four coal fired steam generation units by specific dates.

The current Title V Operation Permit (Title V Permit) includes a number of projects or improvements pursuant to the CFJ and CD including: improved scrubbing efficiency on Units 1 and 2; Low NO_X Burners (LNBs) on Units 1, 2, and 3; installation of new coal nozzles suitable for low NO_X operation; modification redesign of windbox components to allow for proper distribution and staging of air; and installation of a separate overfire air (SOFA) system on Unit 4.

The Title V Permit incorporates the terms of the original PSD permit for Unit 4 that required installation of a wet flue gas desulfurization (FGD) system or scrubber. The same permit incorporates subsequent permits that allowed the routing of exhaust gases from Unit 3 to the Unit 4 scrubber and specifically requires such treatment when petroleum coke is co-fired in Unit 3.

There are several active construction permits implementing requirements pursuant to the CFJ and CD to further reduce NO_X by installation of selective catalytic reduction (SCR) systems. Finally there are provisions in the CFJ and particularly the CD requiring progressive reductions in SO_2, especially for Unit 3. The details are discussed below.

4.0 ORIGINAL UNIT 4 LIMITS AND SUBSEQUENT SCRUBBER IMPROVEMENT

The U.S. Environmental Protection Agency (EPA) issued a PSD (PSD-FL-040) permit to TECO on October 15, 1981 to construct Unit 4. The best available control technology (BACT) determination was 0.82 pounds per million Btu heat input (lb/mmBtu) and was less than the NSPS Subpart Da limit of 1.2 lb/mmBtu. Subpart Da also has a scrubbing efficiency requirement of 90% whenever emissions are between 0.6 and 1.2 lb/mmBtu and 70% whenever they are less than 0.6 lb/mmBtu.

Unit 4 began commercial operation in 1985. Figure 3 is a diagram of the air pollution control equipment on Unit 4.

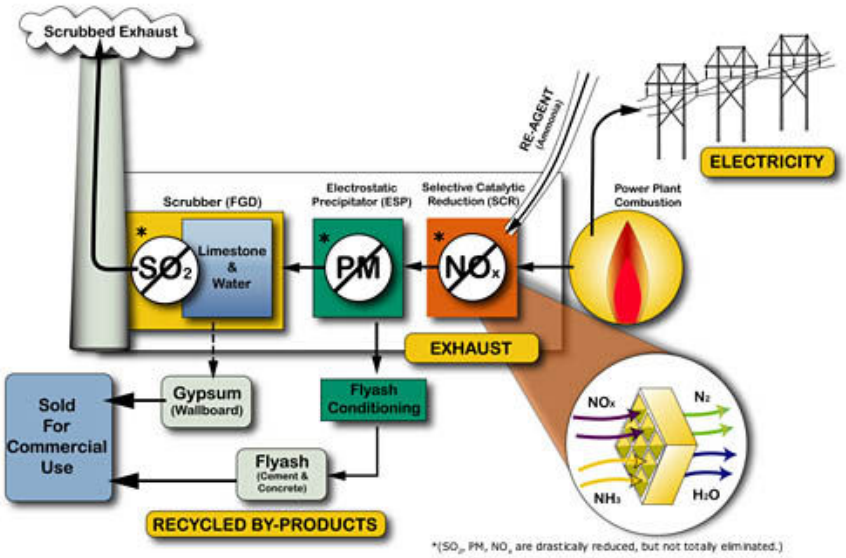

Figure 3. Diagram of Pollution Control Equipment on TECO Big Bend Unit 4

Besides the limit given above, there was a separate requirement pursuant to Subpart Da to achieve scrubbing efficiency on a sliding scale between 70 and 90% depending on the sulfur in the coal.

The wet limestone FGD scrubber was originally designed with four modules (three plus a spare). Based on the results of Department of Energy (DOE) sponsored testing of dibasic acid (DBA) additive on Unit 4 in 1992 TECO conducted modifications to treat flue gas from Unit 3 as well as that from Unit 4 in the original Unit 4 scrubber. This was accomplished by implementing the DBA program and operating all four modules (instead of three) at a maximum flue gas velocity of about 10 to 11 feet per second (ft/s). This velocity is about 50% greater than the original design velocity (DOE, 1997).

The primary benefit of the scrubber improvement is that it provided additional scrubber capacity for TECO Acid Rain SO_2 strategy providing the company with more options regarding sales or purchases of allowances.

5.0 UNITS 3 AND 4 INTERCONNECTION AND PETROLEUM COKE PERMITS

Prior to 1995, the key SO_2 limit applicable to Unit 3 was 6.5 pounds per million Btu lb/mmBtu on a two-hour basis and 8.5 tons per hour (TPH) on a 24-hour basis which equates to more than 74,000 tons per year (TPY). In May 1995 the Department of Environmental Protection (Department) through its Southwest District office issued an amendment of Unit 3 air operating permit (pre Title V). The key change added the following language:

> *"Tampa Electric Company is allowed to divert and integrate all of the Big Bend Unit 3 flue gas for the purposes of treating that flue gas in the existing Big Bend Unit No 4 flue gas desulfurization (FGD) system. While in the integrated mode Units 3 and 4 shall meet the sulfur dioxide emission limitations that are applicable to Unit 4 (40 CFR 60.40a) and Permit No. PSD-FL-040."*

The 1995 action greatly reduced the limits applicable to Unit 3 but only when operating in the interconnected mode. Overall the requirements of Unit 4 remained more stringent than Unit 3 when not operating in interconnected mode. As discussed further below, the requirements for Unit 3 have since become much more stringent and will eventually be more stringent than Unit 4 if not already more stringent than Unit 4.

In September 1995 the Department's Bureau of Air Regulation issued a modification of the Unit 4 PSD permit providing for burning of a blend of coal and petroleum coke (petcoke). The permit did not change the previously cited limits but required adherence to the 90%. Conditions were placed in the permit to insure there would not be an increase in actual emissions resulting from petcoke use. Establishment of a 90% scrubbing provision in lieu of the previous range (70 to 90%) had the effect of increasing the stringency of the Unit 4 limits and also Unit 3 (when interconnected).

In September 1996 the Department's Bureau of Air Regulation issued a further amendment of the Unit 3 permit to provide for combustion of petcoke in Unit 3. The key provision is as follows:

> *"At all times while firing any blend of coal and petroleum coke, Unit No. 3 shall operate only in the integrated mode as described in Specific Condition No. 4 except during startups, shutdowns and/or malfunctions during all of which best operational practices shall be employed including the cessation of petroleum coke bunkering."*

While petcoke tended to increase SO_2 emissions, the scrubbing requirement caused overall emission reductions because petcoke use increased the amount of time during which the stringency of the Unit 3 requirements equaled those of Unit 4.

The changes to the Unit 4 requirements were included in a federally enforceable modification of the PSD permit. The requirements applicable to Unit 3 were not included in an enforceable and public noticed air construction permit. However they have been included in all subsequent Title V permits and the limitations have been made more stringent by the CFJ and especially the CD.

6.0 ADDITIONAL REQUIREMENTS OF THE CD

The CD requirements for SO_2 are more stringent than those of the CFJ. The CD did not change the limits applicable to Unit 4. However it did change the limits applicable to Unit 3 to the point where they are ultimately, if not already, more stringent than those applicable to Unit 4. Under several scenarios, the operation of the scrubber to meet the Unit 3 requirements has affected or can affect the stringency of the Unit 4 limits.

The following table shows the effects of the CD on the emission limits applicable to Unit 3 and Unit 4. The case of operation after the proposed now proposed project to split the scrubber is included though not foreseen in the CD.

Year	Unit 3 SO_2 Limits		Unit 4 SO_2 Limits	
	(lb/mmBtu)	Removal	(lb/mmBtu)	Removal
Before 2000 when not connected	6.5	-	0.82	90%
Before 2000 when interconnected	0.82	90%	0.82	90%
2000-2010 when interconnected	0.82	93%	0.82	93%
2000-2002 only Unit 3 operating	0.35	93%		
2002-2010 only Unit 3 operating	0.30	95%		
2010 if Unit 3 remains coal-fired	0.25	95%		
2000-2010 only Unit 4 operating			0.82	90%
2010 and thereafter interconnected*	0.25	95%	Presumed same as Unit 3	
2010 and thereafter if split*	0.25	95%	0.82	90%

* Inferred from reading of permits and CD that did not actually contemplate scrubber split.

The key point in the table above is that the CD requires that in the long run and by 2010, whatever scrubber serves Unit 3 (presently the Unit 4 scrubber) must achieve a 95% SO_2 removal requirement or achieve 0.25 lb/mmBtu. Also as long as Unit 3 and 4 are served by the same scrubber, Unit 4 will be scrubbed to a greater degree than otherwise required.

7.0 SO_2 EMISSIONS SINCE INTERCONNECTED OPERATION AND CD

The following charts show how SO_2 emissions have changed since the scrubber improvement and integration projects. According to the chart on the left side of Figure 4, Unit 3 SO_2 emissions declined considerably while there was a small increase in annual emissions from Unit 4. The two units together experienced a drop in SO_2 emissions from the range of 60,000 to 65,000 tons per year (TPY) during 1992 and 1994 to less than 20,000 tons in 1995.

Beginning in 2001 and thereafter, total emissions from the two units have been less than 10,000 TPY despite using blends of coal and petroleum coke. In recent years emissions from Unit 4 have been less than they were before sharing the scrubber with Unit 3.

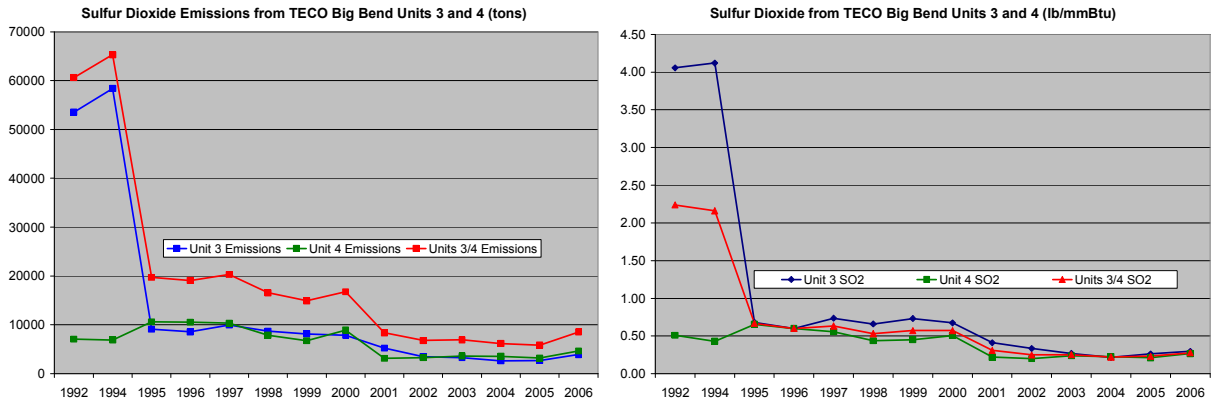

Figure 4. Sulfur Dioxide Emissions from Big Bend Units 3 and 4 in (tons, lb/mmBtu)

The SO_2 emission rates for Unit 3 dropped from values greater than 4.0 lb/mmBtu before commencing integrated operation in 1995 to less than 0.70 lb/mmBtu and eventually to less than 0.30 lb/mmBtu. The Unit 4 emission rate initially increased from approximately 0.5 to nearly 0.7 lb/mmBtu, but progressively fell thereafter to less than 0.30 lb/mmBtu.

The recent data suggest that the 2010 objectives of the CD have been nearly achieved by Unit 3. Furthermore significant reductions in Unit 4 emissions (not specifically required by the CD) from the limit of 0.82 lb/mmBtu have also been realized in part due to the compliance requirements for Unit 3 and by TECO's Acid Rain strategy.

8.0 TECO SCRUBBER SEPARATION PROJECT

Until 2010 Unit 3 may (with certain restrictions) operate up to 30 days per year during scrubber outages. Afterwards Unit 3 exhaust gases must be scrubbed at all times or the unit must be shut down. According to TECO in order to perform maintenance on one unit while the other unit is operating, the common scrubber must be split.

TECO proposes to reconfigure the duct work, split the common scrubber (two of the four modules per unit) and dedicate a separate existing stack to each unit. Unit 3 will be shut down for 6 months beginning in November 2007 to conduct the previously approved SCR installation project. Unit 4 will be shut down for one week in December to complete the scrubber separation. Under the proposed configuration, the gases will no longer be intermingled before or after treatment.

In general there would be concern if a scrubber originally dedicated to one unit (pursuant to a PSD permit and BACT determination) was split in two. According to the company, the overall scrubbing efficiency will be similar to the present operation in that the four modules will still accommodate the two units.

The previous projects resulted in significant actual reductions since 1995 of 50,000 to 55,000 TPY of SO_2 between Units 3 and 4. Also the sum of the emissions from the two units has since 2001 been about the same as the emissions from Unit 4 alone prior to interconnection. Most of the reductions since 1995 occurred due to actions taken by TECO pursuant to its Acid Rain strategy and before the subsequent requirements of the CD.

While it is possible that emissions from Unit 4 could increase after the split (when no longer restricted by Unit 3 efficiency and emission limit requirements in the CD) this is not actually expected by TECO to occur. While the Department does not necessarily agree that splitting the scrubber is the best way to conduct future operations, the Department defers to TECO on this matter. The Department can in the future review data in accordance with its rules to determine whether emissions increases have occurred and whether they are due to the scrubber split.

9.0 MODIFICATION AND PERMITTING APPLICABILITY

TECO claims that the project will not increase either actual or potential emissions and is not a *modification* as defined by Rule 62-210.200(24), F.A.C. Actually the section cited is the definition of *allowable emissions* rather than modification which is defined Rule 62-210.200(205), F.A.C. The relevant part of the definition follows:

> *"Modification" – Any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the* ***actual*** *emissions of any air pollutant subject to regulation under the Act, including any not previously emitted, from any emissions unit or facility. A physical change or change in the method of operation shall not include routine maintenance, repair, or replacement of component parts of an emissions unit.*

There are clearly physical and operational changes associated with splitting the scrubbing and no longer practicing interconnected operation. The described actions are clearly not routine maintenance, repair or replacement. Actually they are quite novel and not at all routine. Actual emissions are defined at Rule 62-210.200(11), F.A.C. as follows:

> *"Actual Emissions" – The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:*
>
> *(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department shall allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.*

*(b) The Department may presume that unit-specific **allowable emissions** for an emissions unit are equivalent to the actual emissions of the emissions unit provided that such unit-specific allowable emissions limits are federally enforceable.*

*(c) For any emissions unit that has not begun normal operations on a particular date, actual emissions shall equal the **potential emissions** of the emissions unit on that date.*

As seen in Table 1, actual emissions in recent years have been very low in terms of TPY and lb/mmBtu. Unit 3 will soon be subject to limits of 0.25 lb SO_2/mmBtu or 95% scrubbing efficiency.

On the other hand, emissions from Unit 4 (after the scrubber split) can theoretically increase from their present low levels of 0.30 lb/mmBtu to the 0.82 or 90%. Realistically emissions of 0.82 lb/mmBtu are highly unlikely but there is not an applicable sulfur limit in the coal.

Also, normal operations have not yet commenced under the split mode with actual separation of the modules compared with the original configuration of Unit 4. Any comparison of recent actual emissions per (a) above with allowable or potential emissions per (b) or (c) above will easily result in an increase of SO_2 emissions.

Department concludes that the proposed project constitutes a modification and an air construction permit is required.

10.0 MAJOR MODIFICATION AND PSD PERMITTING APPLICABILITY

It is also necessary to determine whether the modification is subject to the Department's PSD rules at 62-212.400, F.A.C. The requirements of Sections 62-212.400(4) through (12), F.A.C., apply to major modifications of existing major stationary source. The key criterion is a comparison of *baseline actual* to *projected actual* emissions. Baseline actual emissions are defined for electric utility steam units at Section 62-210.200(36), F.A.C. as follows:

*For any existing electric utility steam generating unit, **baseline actual emissions** means 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 or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation.*

Projected future actual emissions are defined at Section 62-210.200(248) as follows:

"Projected Actual Emissions" – The maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a PSD pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions

increase or a significant net emissions increase at the major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year.

A *major modification* requires a PSD permit and is defined at Section 62-210.200(191), F.A.C. as follows:

"Major Modification" – (a) Any physical change in or change in the method of operation of a major stationary source that would result in a ***significant emissions increase*** *of a PSD pollutant and a* ***significant net emissions increase*** *of that pollutant from the major stationary source.*

Significant emissions rate, for the purpose of determining whether a significant net emissions increase (SNEI) has occurred, is defined at 62-210.200(278), F.A.C. The part of the definition that includes SO_2 is as follows:

"Significant Emissions Rate" – (a) With respect to any emissions increase or any net emissions increase, or the potential of a facility to emit any of the following pollutants, significant emissions rate means a rate of pollutant emissions that would equal or exceed:

1. *A rate listed at 40 CFR 52.21(b)(23)(i), adopted by reference at Rule 62-204.800, F.A.C.; specifically, any of the following rates:*
   a. *Carbon monoxide: 100 tons per year (tpy);*
   b. *Nitrogen oxides: 40 tpy;*
   c. *Sulfur dioxide: 40 tpy; etc.*

The significant emissions rate (SER) for SO_2 of 40 TPY is very low especially compared with the emissions from Unit 3 and 4 over the years. Furthermore it is much less that the difference between actual emissions and allowable or potential emissions discussed in the previous section. Therefore the possibility of a SNEI for SO_2 is a consideration.

11.0 CONCLUSION

The Department's preliminary determination is based on the facts and representations provided by TECO, information on file regarding the previous projects, and the historical data available through the EPA Air Markets Program. The Department also considered the overall effects of the CFD, the CD, the EPA Acid Rain Program and the Clean Air Interstate Rule (CAIR).

Based on the foregoing technical evaluation of the application and other available information, the Department has made a determination that the proposed project will comply with applicable state and federal air pollution regulations. The Department will issue a Draft air construction permit to the applicant that provides for the requested split of the scrubber between Units 3 and 4. Recordkeeping will be required for determining in future years whether a SNEI of SO_2 occurs and is caused by the project.

The Department's determination is strictly limited to this specific case and should not be used as a precedent for other cases, or lead to unintended consequences construed from the language contained in this determination. Ultimately, it is the Department that interprets its own regulations and opinions.