CALPINE

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June 29, 2007

VIA FEDERAL EXPRESS

Mr. Jeff Koerner, P.E.
Florida Department of Environmental Protection
Bureau of Air Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Application for Air Construction Permit Modification
Auburndale Power Partners, L.P.
Facility ID 1050221

Dear Mr. Koerner:

This letter is to request a minor modification to the Air Construction Permit (PSD-FL-185 and subsequent modifications) for the Auburndale Cogeneration Unit, owned by Auburndale Power Partners, L.P. (APP). The cogeneration unit is a 156 (nominal) MW unit (EU 001) operated in combined cycle with an unfired heat recovery steam generator. This unit also generates steam for use by two adjacent manufacturing facilities. The APP unit is permitted to burn natural gas (primary) and #2 fuel oil (back up). The Air Construction Permit has been subsequently modified, in 2002 to allow for the installation of a second unit at the Auburndale facility (EU006, the Auburndale Peaker Energy Center (APEC) unit, permit number 105221-003-AC) and in 2004 to allow for the operation of the unit in wet compression mode (105221-005-AC).

This letter proposes a minor change to the PSD permit for the Auburndale Cogen Unit, correcting the operations data for the previously permitted wet compression operation of the cogeneration unit. The previously submitted data did not properly reflect the operation of the unit with the wet compression system in operation. In order to properly utilize the wet compression system, an increase in the permitted unit heat input during wet compression operation is requested. No increase in the permitted emissions is requested.

Background

In accordance with FDEP permitting rules, permit number (PSD-FL-185) and subsequent permits including the current Title V operating permit (105221-009-AV) includes a maximum heat input rate, at standard (ISO) conditions. This limit was established in the initial 1992 permitting. Subsequently, a correction curve showing the calculation of adjusted heat inputs for varying compressor inlet temperatures was submitted to the department (see discussion below). At the time of the permitting for wet compression operation, APP agreed to continue operation in accordance with this limit and provided a second correction curve with that permitting information.

Following analysis of actual operations data over the last two years, and in particular the identification of apparent exceedences of the heat input limit during wet compression operation (see letter to FDEP Southwest District dated June 4, 2007), APP has determined that the operation curve provided with the permitting material for the wet compression did not accurately describe the operation of the unit in wet compression mode. The purpose of this application is to provide an accurate operations curve for the wet compression operation and to request a permit modification to allow operation in accordance with that curve. This application does not request any change to the limits and conditions of dry operation or any changes to the existing emissions limits for any emitted pollutants.

The PSD-FL-185 contained a limit on the heat input for operation using both natural gas and fuel oil. Specific Condition 5 states:

> 5. *The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:*
>
> ...
>
> d. *The maximum heat input of 1,170 MMBtu/hr LHV at ISO conditions (base load) for distillate fuel oil No. 2.*
>
> e. *The maximum heat input of 1,214 MMBtu/hr LHV at ISO conditions (base load) for natural gas.*

This condition is reflected in the current Title V permit (105221-009-AV) as follows:

Permit Condition A.1.- Permitted Capacity. The maximum heat input to the combustion turbine (CT) shall not exceed 1214 MMBtu/hr as determined using a lower heating value (LHV) at International Standards Organization (ISO) conditions while firing natural gas and 1170 MMBtu/hr as determined using LHV at ISO conditions while firing No. 2 distillate fuel oil.

The wet compression operation was permitted in modification permit 105221-005-AC which states:

> *Wet Compression System*
>
> *A wet compression system may be installed on Unit 1. Operation of the wet compression system is approved for use on Unit 1 during periods at which the ambient temperature is above 60 degrees F. Use of the wet compression system is limited to periods during the firing of natural gas only.*

A correction curve was attached to the initial Title V permit (105221-002-AV) for operation of the turbine without wet compression (dry operation). The following correction equation has been calculated to fit this curve:

*HIc =HIm / [1.1794-0.003*CIT]* *(Curve A)*

Where:

HIc-Heat input corrected to permitted condition (LHV at ISO)
HIm-Measured heat input
CIT-Compressor Inlet Temperature

This equation and the curve it represents serve to correct values of heat input at various operating temperatures (compressor inlet temperature) to the ISO standard condition for evaluation against the permit standard.

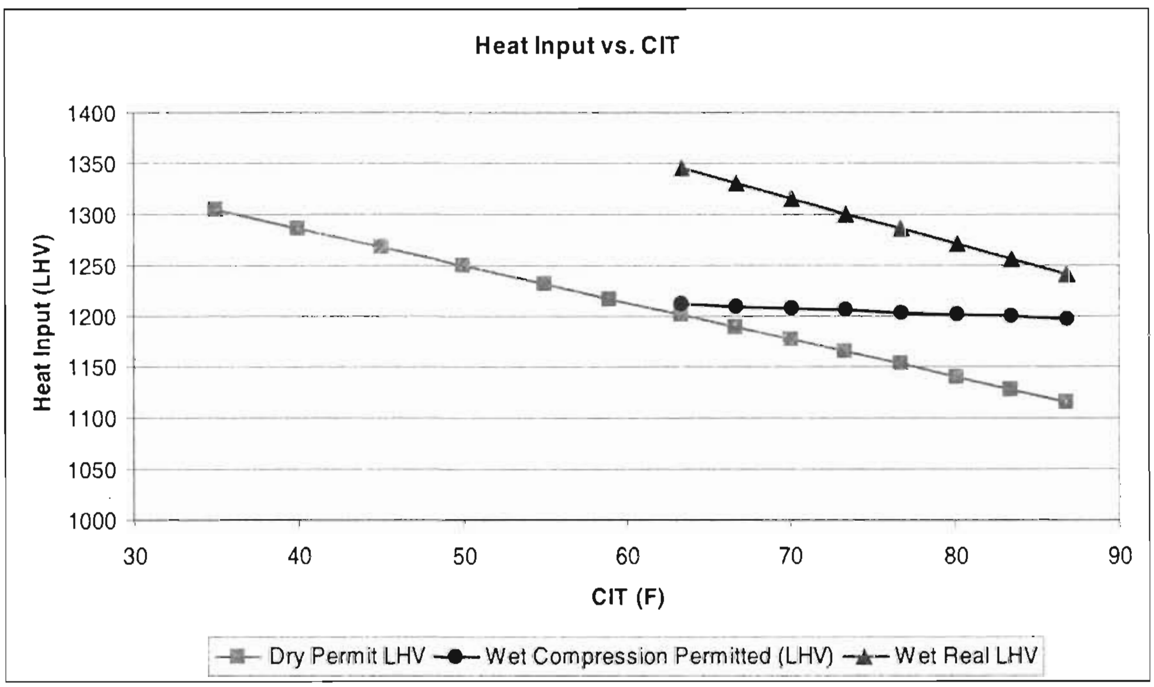
As a part of the application process for permission to operate the wet compression system, an anticipated heat input curve based on ambient temperature was submitted. The facility has since created a correction equation based on that data.

*HIc =HIm / [1.0201-0.0003*Ambient]* *(Curve B)*

Where:

HIc-Heat input corrected to permitted condition (LHV at ISO)
HIm-Measured heat input
Ambient-Ambient Dry Temperature Fahrenheit

During subsequent operation of the unit, it has been identified that the Curve B does not accurately reflect the actual operation of the wet compression system. In fact, the wet compression system operates along a curve with essentially the same slope as the dry operation curve calculated in Equation A. The wet compression system allows the turbine to operate at a higher heat input for any given compressor inlet temperature. APP has created Figure 1 to demonstrate the difference in actual operation in wet compression mode compared to the previously submitted line.



The correction factor for the actual operation of the unit with wet compression on is essentially identical to that for dry operation. The use of the wet compression system results in an increase in heat input of approximately 150 mmBtu/hr LHV at ISO. The previously permitted wet compression operation line does not properly reflect the operation of the wet compression system, although APP has been constraining the unit's operation to maintain compliance.

Requested Change

In order to allow operation of the wet compression system at its full capacity, APP requests that the permit conditions cited above be modified as follows:

Condition 5.e. of PSD-FL-185 be modified to read

e. The maximum heat input of 1,214 MMBtu/hr LHV at ISO conditions (base load) for natural gas with the wet compression system off (dry operation) or 1,364 MMBtu/hr LHV at ISO conditions for natural gas with the wet compression system in operation.

Condition A.1 of the Title V permit be modified to read

Permit Condition A.1.- Permitted Capacity. The maximum heat input to the combustion turbine (CT) shall not exceed 1214 MMBtu/hr as determined using a lower heating value (LHV) at International Standards Organization (ISO) conditions while firing natural gas with the wet compression system off (dry operation) or 1,364 MMBtu/hr LHV at ISO conditions for natural gas with the wet compression system in operation *and 1170 MMBtu/hr as determined using LHV at ISO conditions while firing No. 2 distillate fuel oil.*

Impact on Emissions

APP is not requesting any other changes in the permit conditions. NOx emissions from the unit are limited on a lb/hr basis, a 24 hour average concentration basis, an annual average concentration basis and an annual mass emission basis (TPY). These conditions were updated in the PSD modification that permitted the addition of the peaking unit (105221-004-AC) and are summarized here.

NOx Concentration	15 ppm (24-hour average)
NOx Concentration	9 ppm (annual equivalent average)
NOx Mass	78.6 lb/hr
NOx Mass	177 tons/year (annual total).

APP will not exceed any of these currently existing thresholds. FDEP has also evaluated the CO emissions in connection with the PSD modification to add the peaker. Although the new condition (that the peaker may not emit more than 99 TPY of CO) is placed on the peaker, APP understands that FDEP intends that the CO emissions also be constrained by the limits placed in the permit and that no increase in the CO emissions occur. Although APP is not required to monitor CO on a continuous basis, APP does test the CO emissions from this unit in accordance with permit conditions. During a recent testing event, APP tested the CO with the wet compression system in operation. Data from this event is shown in Attachment 2. This test was conducted at the following average conditions:

Ambient Temperature	84.9
Compressor Inlet Temperature	78.6
Water Flow	80 gpm
Heat Input (HHV)	1274.7 mmBtu/hr
Heat Input (LHV)	1149.8 mmBtu/hr
Heat Input adjusted to ISO (Curve A)	1085.0 mmBtu/hr

Average emissions during the test were as follows:

NOx (ppm)	11.9
NOx (lb/hr)	56.3
NOx (lb/mmbtu)	0.044
CO (ppm)	0.69
CO (lb/hr)	1.99
CO (lb/mmbtu)	0.002

These emissions rates demonstrate that the emissions from the unit, operating with the permitted wet compression, even at the proposed higher heat input rate, would not exceed any of the existing permitted emissions rates or limits.

During the evaluation of APP's application to install the wet compression system, FDEP did an analysis of potential increases in emissions (See Enclosure 2: DEP File No. 1050221-005-AC pages TE4 – TE6). Following the methodology used by FDEP in that analysis, APP presents the following data:

MAXIMUM HEAT INPUT INCREASE

Previously the addition of the wet compression was evaluated by calculating the increased potential heat input based on the amount of additional heat input to the unit which would be achieved at temperatures greater than 60 degrees F. Using the average temperatures for Tampa, Florida and the data provided by APP in 2002, FDEP calculated an increase in the heat input of 303,888 MMBtu/yr and used this value to calculated potential increases in emissions. Table 1, below uses the same approach to calculate increases in heat input for the proposed modification. It is important to note that in this analysis, the increase in heat input calculated is compared to the operation of the unit without wet compression (dry), and does not take "credit" for the heat input increase considered in the previous approval of the wet compression system in 1050221-005-AC. Using this analysis, the increase in heat input is calculated to be 1,245,934 MMBtu for the year. An alternate approach would be to consider that the average number of hours per year above 60 degrees F for the area is 7854 and that the approximate increase in the heat input from the wet compression is 150 MMBtu/hr for an annual potential heat input increase of 1,178,100 MMBtu.

Table 1
Potential Heat Input Increase Data

Month	Ambient Temperature	CIT	Hours per Month	Heat Input Normal (Dry) Operation MMBtu/hr	Previously Evaluated Heat Input Wet Compression MMBtu/hr	Proposed Heat Input Wet Compression MMBtu/hr	Potential Monthly Heat Input Normal (Dry) Operation MMBtu	Proposed Potential Monthly Wet Compression MMBtu	Heat Input Increase MMBtu
January	59.9	59.9	744	1294	1294	1294	962,351	962,736	NA
February	61.5	61.0	672	1289	1301	1449	866,426	973,480	107,054
March	66.6	64.4	744	1276	1299	1434	949,394	1,066,700	117,306
April	71.3	67.6	720	1264	1297	1420	909,972	1,022,407	112,435
May	77.4	71.7	744	1248	1294	1402	928,507	1,043,233	114,725
June	81.3	74.3	720	1238	1293	1391	891,256	1,001,379	110,122
July	82.4	75.0	744	1235	1292	1388	918,838	1,032,368	113,530
August	82.4	75.0	744	1235	1292	1388	918,838	1,032,368	113,530
September	80.9	74.0	720	1239	1293	1392	892,005	1,002,220	110,215
October	74.8	69.9	744	1255	1295	1410	933,536	1,048,882	115,346
November	67.5	65.0	720	1274	1299	1431	917,084	1,030,398	113,314
December	62.2	61.5	744	1288	1301	1447	957,903	1,076,261	118,357
Total							11,046,114	1,2,292,433	1,245,934

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Based on the increase of 1,245,934 MMBtu/yr, we calculate the following increase in the facility emissions shown in Table 2.

Table 2

Pollutant	Emissions Factor	Increased Annual lbs	Increased TPY	PSD Significant Emission Rate	Review Required
PM_{10}	0.008	9967	5.0	15	No
SO_2	0.0006	748	0.4	40	No
NOx	0.056 0.033	69,416 41,116	34.7 20.6	40	No
CO_2	0.034	42,362	21.2	100	No

[1] Emissions Factor value is EPA default value for combustion of pipeline natural gas.
[2] At 15 ppm, NOx emissions are 0.056 lb/MMBtu. However, the unit has an annual limit of 9 ppm annual equivalent average. The unit cannot operate at 15 ppm for more than 7000 hours and still meet the 9 ppm average. The value 0.033 lb/MMBtu represents the emissions rate at 9 ppm.

As shown in the above table, potential increases in emissions of regulated pollutants are below the PSD thresholds. As noted above, this facility underwent PSD review in 2002 related to the installation of the peaking unit and that review established an annual emission limit of 177 TPY of NOx for this emission unit.

This letter proposes a minor change to the PSD permit for the Auburndale Cogen Unit, correcting the operations data for the previously permitted wet compression operation of the cogeneration unit. The previously submitted data did not properly reflect the operation of the unit with the wet compression system in operation. In order to properly utilize the wet compression system, an increase in the permitted unit heat input with during wet compression operation is requested. No increase in the permitted emissions is requested.

We hope that the information supplied will meet the department's need to evaluate this request. If you have questions or need additional information, please do not hesitate to contact me via telephone at (713) 570-4795 or via email at jgoodwin@calpine.com; or Heidi Whidden at (713) 570-4829 or hwhidden@calpine.com.

Sincerely,

AUBURNDALE POWER PARTNERS, L.P.

Jason M. Goodwin, P.E.
Director - Environmental, Health & Safety
Eastern Power Region

Enclosures: 1) Data from RATA
2) Technical Evaluation from 1050221-005-AC

Enclosure 1:

Data from RATA

TABLE 3
Summary of Results
Compliance Testing

Company: Auburndale Power Partners, LP
Plant: Auburndale Energy Center
Location: Auburndale, Polk County, Florida
Technicians: LJB, CDH
Source: Cogen Unit 1, a Siemens Westinghouse 501D5 Combustion Turbine

Test Number	U1-C-1	U1-C-2	U1-C-3		
Date	05/18/07	05/18/07	05/18/07		
Start Time (CEMS Time)	12:08	13:55	15:35		FDEP
Stop Time (CEMS Time)	13:41	15:23	17:02		Permit
Power Turbine Operation				*Averages*	Limits
Generator Output (MW)	109.1	110.2	108.9	***109.4***	
Net Unit Output (MW, includes steam turbine)	151.8	152.8	151.3	***152.0***	
Barometric Pressure ("Hg)	29.77	29.75	29.76	***29.76***	
Compressor Inlet Temperature (°F)	79.0	77.2	79.7	***78.6***	
Compressor Discharge Pressure (psia)	201.76	202.73	201.40	***201.96***	
Compressor Discharge Temperature (°F)	698.3	697.6	699.4	***698.4***	
Mean Turbine Exhaust Temperature (°F)	1019.4	1018.8	1020.2	***1019.5***	
NH_3 Injection Rate (lbs/hr)	103.18	100.83	96.46	***100.16***	
SCR Inlet Temperature (°F)	581.6	580.7	579.7	***580.7***	
Stack Outlet Temperature (°F)	231.2	231.1	230.4	***230.9***	
Steam Injection Flow (KPPH)	54.07	57.18	55.12	***55.46***	
Turbine Fuel Data (Natural Gas)					
Fuel Heating Value (Btu/SCF, Gross)	1033.5	1033.5	1033.5	***1033.5***	
Fuel Specific Gravity	0.5859	0.5859	0.5859	***0.5859***	
O_2 "F_d-Factor" (DSCFex/MMBtu @ 0% excess air)	8643	8643	8643	***8643***	
CO_2 "F_c-Factor" (DSCFex/MMBtu @ 0% excess air)	1028	1028	1028	***1028***	
Turbine Gas Fuel Flow (SCFM, PI Data)	20,331	20,452	20,303	***20,362***	
Turbine Gas Fuel Flow (KSCFH, PI Data)	1219.8	1227.1	1218.2	***1221.7***	
Turbine Gas Fuel Flow (kSCFH, CEMS data)	1232.0	1235.7	1232.5	***1233.4***	
Heat Input (CEMS data MMBtu/hr, Higher Heating Value)	1273.2	1277.1	1273.8	***1274.7***	
Heat Input (CEMS data MMBtu/hr, Lower Heating Value)	1148.5	1152.0	1149.0	***1149.8***	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.75	29.73	29.73	***29.74***	
Temperature (°F): Dry Bulb	86.8	85.9	82.0	***84.9***	
(°F): Wet Bulb	73.1	73.3	73.2	***73.2***	
Humidity (lbs moisture/lb of air)	0.0140	0.0144	0.0152	***0.0145***	
Measured Emissions					
NO_X (ppmv, dry basis)	12.94	13.29	13.66	***13.30***	
NO_X (ppmv, dry @ 15% excess O_2)	**11.6**	**11.8**	**12.2**	***11.9***	**15.0**
CO (ppmv, dry basis)	0.71	0.73	0.88	***0.77***	
CO (ppmv, dry @ 15% excess O_2)	**0.63**	**0.65**	**0.79**	***0.69***	**15**
THC as VOC (ppmv, wet as Methane)	-0.08	-0.07	0.29	***0.04***	
VE (% opacity)	**-**	**0**	**-**	***0***	**10**
O_2 (% volume, dry basis)	14.30	14.28	14.29	***14.29***	
CO_2 (% volume, dry basis)	3.95	3.96	3.97	***3.96***	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.67	1.67	1.66	***1.67***	
Stack Volumetric Flow Rate (via EPA Method 19, using CEMS Fuel Flow)					
via O_2 "F_d Factor" (SCFH, dry basis)	3.55E+07	3.55E+07	3.54E+07	***3.55E+07***	
via CO_2 "F_c Factor" (SCFH, dry basis)	3.37E+07	3.37E+07	3.36E+07	***3.37E+07***	
Calculated Emission Rates (via M-19)					
NO_X (lbs/hr)	**54.8**	**56.3**	**57.8**	***56.3***	**78.6**
CO (lbs/hr)	**1.83**	**1.88**	**2.27**	***1.99***	**43.5**

Enclosure 2:

Technical Evaluation from 1050221-005-AC

TECHNICAL EVALUATION

AND

PSD APPLICABILITY DETERMINATION

Auburndale Power Partners LP - Calpine

Wet Compression Modification

Combined Cycle Unit EU-001

Polk County

1050221-005-AC

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

January 28, 2002

TECHNICAL EVALUATION AND PSD DETERMINATION

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Auburndale Power Partners L.P.
Auburndale Unit 1
1501 West Derby Avenue
Auburndale, Florida 33823-4079

Authorized Representative: Benjamin M.H. Borsch, P.E. Environmental Manager, Calpine

1.2 REVIEWING AND PROCESS SCHEDULE

October 3, 2000	Received Permit Application
October 19, 2001	Request For Additional Information
January 22, 2002	Received Additional Information
January 22, 2002	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located in Auburndale, Polk County. The UTM coordinates are Zone 17; 420.8 km E; 3103.2 km N. This site is approximately 95 kilometers from Chassahowitzka Wildlife Refuge, a Class I PSD Area.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

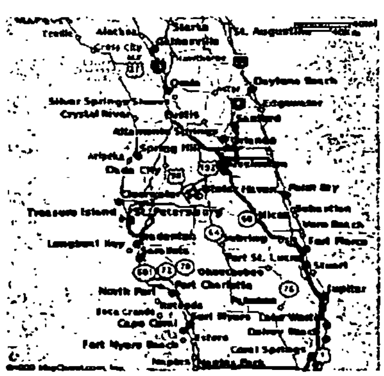
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

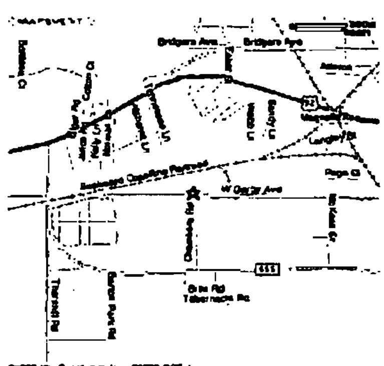
2.3 FACILITY CATEGORY

The existing facility is a cogeneration plant consisting of a combined cycle combustion turbine cogeneration system rated at 156 total megawatts (MW) output and a simple cycle peaking unit, rated at 104 MW nominally. The combined cycle system consists of one combustion turbine (CT), one unfired heat recovery steam generator (HRSG), and one steam turbine-generator. The facility utilizes pipeline natural gas as its primary fuel source and low sulfur (0.05 % by weight) distillate fuel oil as a backup fuel source. Also located at this facility are two distillate fuel oil storage tanks, and miscellaneous unregulated/insignificant emissions units and/or activities.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Based upon the Title V application, the facility is not a major source of hazardous air pollutants (HAPs).





3. DESCRIPTION

This project addresses the following existing emissions unit:

Emissions Unit No.	Emissions Unit Description
001	Combined cycle combustion turbine (CT) cogeneration system with a combined total output of 156 MW. The combined cycle system consists of one 104 MW Westinghouse 501D5 combustion turbine (CT), one 52 MW steam turbine-generator, and one HRSG. The HRSG is not fuel fired. Water injection, SCR and good combustion practices are used to control air pollutant emissions. The maximum heat input to the combustion turbine (CT) is 1214 MMBtu/hr as determined using a lower heating value (LHV) at International Standards Organization (ISO) conditions while firing natural gas and 1170 MMBtu/hr as determined using a LHV at ISO conditions while firing 0.05% sulfur distillate fuel oil.

3.1 PROJECT DESCRIPTION

The applicant proposes to install a wet compression system for use at temperatures above 60 degrees F. This system is proposed for use while firing natural gas (only). The Department has made prior Determinations for the application of inlet foggers, and has typically found those applications to result in de minimis increases in PSD pollutants. However, this is the first such application of wet compression, causing the Department to undertake a rigorous PSD examination. Accordingly, the Department will evaluate whether the anticipated increases in emissions are sufficient to cause of review of Best Available Control Technologies.

According to publicly available data, wet compression has the ability to increase fuel flow by as much as 13.8% on a 90 degree F day, at 60% R.H. and sea level.

Typical wet compression performance (W501D5A gas turbine)

	Dry	Wet compression	Change
GT power (MW)	106	122	+15%
GT heat rate (Btu/kWh)	10240	10120	-1.2%
GT fuel flow (lb/h)	50425	57360	+13.8%
ST power (MW)	49	51	+4%
CC power (MW)	151	169	+12%
CC heat rate (Btu/kWh)	7190	7310	+1.7%

Much of the following was obtained from an article entitled "*Wet compression extended to V-series machines*" in **Modern Power Systems**, September 21, 2001.

3.2 WET COMPRESSION

In recent years there has been growing interest in ways of boosting the output of existing gas turbines by conditioning the air input to the compressor. There are two main categories of such technology. The first involves the introduction of water and cooling of the air through the enthalpy of evaporation of the water. In this category are wet compression, inlet fogging and evaporative cooling. The second category involves use of a heat exchanger to reduce air inlet temperature, without addition of water. In this category, which results in a lowering of inlet air humidity rather than an increase, are inlet chilling and refrigeration.

Wet compression was developed in the early 1990s by Dow Chemicals, which holds the patent. Siemens Westinghouse has applied it commercially to around 20 installations, all of them Westinghouse W501 type gas turbines. The initial installation has operated for over 25000 hours on a W501A machine, since 1995. The first installation on a W501D5A (DLN) turbine was in 1997, while 1999 saw the first installation on W501D5 and W501D5A machines. Recently, tests of the wet compression technology have been carried out on a Siemens type V84.3A2 gas turbine at the Siemens test bed in Berlin. A prototype application of the technology on a V84.2 machine is planned for the spring of 2002 at a US plant. Subsequently, the technology will be tested on a V94.2 gas turbine, also slated for 2002.

Siemens Westinghouse believes that wet compression is the most cost effective of the common techniques for augmenting gas turbine output. It reportedly can increase gas turbine power output by 10-15 percent and raise efficiency by 1-2 percent. When fitted on engines with conventional combustion systems, NO_X emissions have been reduced by 20-40 percent. In terms of CO_2, wet compression increases fuel consumption, but the increase in power is greater, resulting in less CO_2 emissions per unit of power generated. As mentioned below, another advantage of wet compression is that it allows power to be increased and maintained independent of ambient temperatures and relative humidity – it even works with relative humidity of 100 percent. It can also be used in conjunction with evaporative cooling.

Wet compression can have advantages over direct combustor water injection for NO_X control and power enhancement. In the case of water injection, heat rate is increased (due to vaporization of the water), whereas wet compression improves heat rate while at the same time intercooling the compressor. It should however be noted that in a combined cycle application, wet compression increases heat rate. This is because, with wet compression, gas turbine fuel consumption increases in line with the power increase, but turbine exhaust energy increases to a lesser extent.

The thermodynamics of wet compression is relatively straightforward. The compressor inlet air is over-saturated, with the double effect of cooling at the compressor inlet (dependent on ambient conditions) and intercooling, i.e. cooling inside the compressor (which is independent of ambient conditions). Thermodynamics dictates that an isothermal compression will consume less work than an adiabatic compression. Once the over-saturated air is inside the compressor, the evaporation of the remaining droplets provides intercooling and thus moves the compression in the direction of an isothermal process. As an additional effect the overall increase in the mass flow increases the power output from the turbine.

Wet compression technology does not suit all turbines because the intercooling effect will change the operating gaps in the compressor. Droplet sizes must be carefully controlled to minimize erosion of the compressor blades. Also, wet compression causes the pressure ratios inside the gas turbine to vary, which results in changes to the cooling air management requirements. These and other effects are influencing the commercialization of wet compression technology.

A wet compression system includes fitting of the spray atomization system and spray nozzle rack, modifications to the plant control system (e.g. to adjust firing temperature as a function of the quantity of water being injected), installation of high pressure pumps, application of protective coatings to the inlet ducts, and installation of water traps in first compressor bleed lines. The injection of water changes the work distribution of the compressor and requires changes to turbine cooling circuits and usually installation of an automated flow control system. Since its introduction some six years ago the technology has evolved in a number of ways, including improved nozzle design and reduced average droplet size.

Tests on the V84.3A2 turbine at the Siemens test facility in Berlin have aimed to gather basic thermodynamic data for the Siemens V series machines. The tests were conducted for fuel oil and fuel gas premix modes with low NO_X combustors. The V84.3A2 had test instrumentation to monitor the following: vibration and natural frequency of the compressor blades; compressor blade tip clearances; compressor casing temperature distribution and deformation; pressures and temperatures in bleeds; and thermodynamic values. With an injected water temperature of less than 30°C, ambient conditions of 22 to 23.3°C, 1004 mbar, and 60 percent relative humidity, the wet compression gave a power gain in the range 10-15 percent. The tests demonstrated successful application of the technology to the V series.

3.3 ALTERNATIVES TO WET COMPRESSION

Evaporative cooling is a widely used technology for boosting gas turbine output, particularly in dry and hot climates. Unlike wet compression, where water is sprayed into the compressor inlet, evaporative cooling uses a stationary water saturated medium, over which the inlet air is passed. Because the residence time is short, evaporative cooling does not allow the air to become fully saturated, achieving humidity levels in the range 85-95 percent. Typically the hardware for evaporative cooling is installed in the inlet filter house, well upstream of the compressor inlet. In contrast the spray rack for wet compression is installed close to the compressor inlet.

Like wet compression, inlet fogging/misting involve the direct spraying of water into the inlet air, with the possibility of achieving 100 percent humidity. However, like evaporative cooling the fogging/misting is done close to the filter house and as far away as possible from the compressor inlet. This is to allow maximum time for the drops to evaporate before entering the turbine. The disadvantage of being so far from the inlet is that a large amount of ductwork gets wet, which can cause corrosion, and contaminants on the ductwork can get washed into the turbine.

Recently, turbine inlet chilling has been applied in particular market niches. The chilling can be done with absorption refrigeration, electric chillers or even ice. In some cases non-peak electricity can be used to make ice or chilled water, which can then be used to boost output during peak times, when electricity prices are high. However, according to recent figures presented by Siemens Westinghouse (Power Gen conference, Brussels, May 2001) these refrigeration and storage systems can be expensive and installation may take up a large amount of space.

Wet compression can also be used in addition to evaporative cooling, with consequent benefits; wet compression allows a gas turbine to maintain output with increasing ambient temperatures. Siemens Westinghouse argues that power gains from wet compression are more reliable than those from evaporative cooling and inlet fogging because they are not dependent on the relative ambient air humidity.

4. PROJECT EMISSIONS

4.1 MAXIMUM HEAT INPUT INCREASE

The only logical impact to emissions resulting from the installation of the wet compression system is related to the increased heat input (rather than increases in hours of operation), which will be achieved at temperatures greater than 60 degrees F. The chart below represents a monthly table of average temperatures for Tampa, Florida based upon National Weather Service data. It additionally shows the correlating heat input (HHV), as well as the expected heat input during wet compression, both based upon the submitted data.

Month	Normal Daily Temperature	Hours in Month	Heat Input At Normal Temperature	Heat input During wet compression	Increased Heat Input	Heat Input Increase MMBtu[1]
January	59.9	744	1294	N/A	N/A	N/A
February	61.5	672	1289	1301	12	8064
March	66.6	744	1276	1299	23	17112
April	71.3	720	1264	1297	33	23760
May	77.4	744	1248	1294	46	34224
June	81.3	720	1238	1293	55	39600
July	82.4	744	1235	1292	57	42408
August	82.4	744	1235	1292	57	42408
September	80.9	720	1239	1293	54	38880
October	74.8	744	1255	1295	40	29760
November	67.5	720	1274	1299	25	18000
December	62.2	744	1288	1301	13	9672
ANNUAL			AVG = 1261			303,888

[1] Based upon continuous gas firing

4.2 MAXIMUM POTENTIAL TO EMIT (PTE)

In order to determine whether the increased annual heat input will trigger a PSD Review, the following emission factors were utilized. These are calculated based upon the original BACT determined Ton Per Year (TPY) emissions and an average (HHV) heat input of 1261 MMBtu/hour (from above). Additionally, an annual increase in heat input of 303,888 MMBtu was assumed (from above).

Pollutant	Emission Factor (lbs/MMBtu)	Increased Annual lbs	Increased TPY	PSD Significant Emission Rate	Review Required
PM_{10}	0.008	2431	1.2	15	No
SO_2	0.032	9724.4	4.9	40	No
NO_X	0.062	18841	9.4	40	No
CO	0.034	10332	5.2	100	No

As shown in the above table, potential increases in emissions of regulated pollutants are well below the PSD thresholds; hence a PSD Review is not required. Of note, this facility recently underwent a PSD Review related to the installation of a new peaking unit, and that review established an annual emission limit of 177 TPY of NO_X for this Emission Unit.

5.0 CONCLUSION

Based on the foregoing technical evaluation of the application, additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project will not trigger a PSD Review. This conclusion is consistent with prior Determinations made for the installation of foggers. However, a similar review should be undertaken for combustion turbines representative of F classes and above.

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