COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHEAST REGIONAL OFFICE
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August 21, 2007

Leonard J. Ariagno
Somerset Power LLC
Somerset Operations, Inc.
1606 Riverside Avenue
Somerset, Massachusetts 02726

RE: **PROPOSED CONDITIONAL APPROVAL**
Application for: BWP AQ 02
Non-Major Comprehensive Plan Applications
310 CMR 7.02 Plan Approval and Emission Limitations
Transmittal No.: W101376
Application No.: 4B06046
Source Number: 0060

AT: Somerset Power LLC
1606 Riverside Avenue
Somerset, Massachusetts 02726

Dear Mr. Ariagno:

The Department of Environmental Protection (the Department or MassDEP), Bureau of Waste Prevention (BWP), has reviewed the Non-Major Comprehensive Plan Application (NMCPA), submitted by Somerset Power LLC (the Applicant), for proposed modifications to the Somerset Station (Facility) located at 1606 Riverside Avenue, Somerset, Massachusetts.

Proposed modifications to the Somerset Station include alterations to existing Unit 6/Boiler 8 coal fired electric utility generating unit. The proposed modifications will convert Boiler 8 from a conventional pulverized coal-fired boiler to a synthetic gas (syngas) fired boiler. Syngas will be produced by plasma gasification of coal and/or biomass feed stocks followed by a syngas cleanup train. The project will include the physical removal of Boiler 8 existing coal burners and pulverizers.

The application was prepared by ENSR and bears the seal and signature of Michael Kravett, P.E. No. 46489.

On April 2, 2007 Somerset Power LLC submitted an Amended 310 Code of Massachusetts Regulations (CMR) 7.29 Emission Control Plan (ECP) application (4B07009) for the proposed conversion of Unit 6/Boiler 8 from coal to syngas pursuant to 310 CMR 7.29(6)(h).

The Unit 6/Boiler 8 syngas fuel conversion project does not constitute "Repowering" as defined in 310 CMR 7.00 Definitions and 310 CMR 7.29(2) even though the burning of syngas will realize significant emission reductions and require substantive modifications to Unit 6/Boiler 8. However, the Department recognizes the Applicant's right to propose amendments to the approved ECP pursuant to 310 CMR 7.29(6)(h).

Currently, Somerset Power LLC operates a natural gas reburn system to meet the emission limits contained in the ECP Final Approval (4B01043) dated June 7, 2002, issued pursuant to 310 CMR 7.29 Emissions Standards for Power Plants. On February 24, 2003, the Department issued a Conditional Approval (4B02023) for the construction and operation of the natural gas reburn system pursuant to 310 CMR 7.02 Plan Approval and Emission Limitations. The Conditional Approval (4B02023) will remain in effect in the event that the Unit 6/Boiler 8 project to convert from a conventional pulverized coal-fired boiler to a syngas fired boiler does not go forward.

On December 22, 2006, Somerset Power LLC submitted the NMCPA (4B06046) in accordance with 310 CMR 7.02. The Department is of the opinion that the NMCPA is in conformance with the current Massachusetts Air Pollution Control Regulations and hereby **PROPOSES to CONDITIONALLY APPROVE** the proposed alterations of the facility, subject to the conditions and provisions stated herein. The Department's review has been limited to compliance with applicable Air Pollution Control Regulations and does not relieve you of the obligation to comply with all other permitting requirements contained in other regulations or statutes.

This PROPOSED CONDITIONAL APPROVAL combines and includes: the 310 CMR 7.02 Comprehensive Plan Approval; the 310 CMR 7.00: Appendix A: Emission Offsets and Nonattainment Review analysis; and the Code of Federal Regulations (CFR), Title 40, Part 52.21 Prevention of Significant Deterioration (PSD) analysis, and hereby incorporates the NMCPA submitted by the Applicant by reference, including the Amended ECP application and Amended ECP Final Approval (4B07009).

The Department will hold a public hearing to receive comment on the Department's Proposed Conditional Approval.

The CONDITIONAL APPROVAL, when issued, will allow for commencement of proposed construction and/or alterations of the facility and its operation, and provide information on the project description, emission control systems, facility limits, continuous emission monitors, record keeping, reporting and testing requirements. A list of the submitted information pertinent to the application is delineated on page 27 of 28.

Should you have any questions concerning this matter, please feel free to contact the undersigned at (508) 946-2779.

Very truly yours,

John K. Winkler, Chief
Permit Section
Bureau of Waste Prevention

Enclosures

cc: Brendan McCahill
U.S. EPA Region I – Air Permits
One Congress St., (CAP)
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ecc: Alan Sawyer, NRG Energy, Inc., Princeton, NJ
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TABLE OF CONTENTS

List of Abbreviations

BACT………..………Best Available Control Technology
Btu/kWh…………….British Thermal Units per kilowatt hour
Btu/lb………………..British Thermal Units per pound
BWP…………………Bureau of Waste Prevention
CEM……………...…continuous emission monitor
CFR…………………Code of Federal Regulations
CMR………………...Code of Massachusetts Regulations
COM……………..…..continuous opacity monitor
CO…………………..carbon monoxide
CO_2………………….carbon dioxide
dB(A)…………………decibels (A-weighted sound level)
ECP…………………Emission Control Plan
EPA…………………U.S. Environmental Protection Agency
ESP………………….electrostatic precipitator
FF…………………...fabric filter
Hg……….…………mercury
HAP………………...Hazardous Air Pollutant
HCl………………..…hydrochloric acid
HHV………………...higher heating value
H_2SO_4……………….sulfuric acid
lb/GWh……………...pounds per gigawatt hour
lb/hr…………………pound per hour
lb/MMBtu…..……….pound per million British Thermal Units
lb/MWh…….……….pound per megawatt hour
LAER……………….lowest achievable emission rate
MARAMA………….Mid-Atlantic Regional Air Management Association
MassDEP…………...Massachusetts Department of Environmental Protection
MCR………………..maximum continuous rating
MMBtu/hr…………..Million British Thermal Units per hour
MW…………………megawatt
NA………………….nonattainment
NAAQS…………….National Ambient Air Quality Standards
NH_3…………………ammonia
NMCPA…………….Non-Major Comprehensive Plan Application
NO_2…………………nitrogen dioxide
NO_x…………….…...nitrogen oxides
NSPS………………..New Source Performance Standards
NSR………………...New Source Review
O_3…………………...ozone
OGC………………..Office of General Counsel
ppm_{vd} @ 3% O_2…….parts per million volume dry corrected to three percent oxygen
Pb…………………...lead
PM…………………..particulate matter
PM_{10}………………...particulate matter less than or equal to 10 microns in diameter
$PM_{2.5}$………………..particulate matter less than or equal to 2.5 microns in diameter
psig………………….pounds per square inch gauge
PTE…………………potential to emit
RACT……………….Reasonably Available Control Technology
RATA……………….Relative Accuracy Test Audit
RBLC……………….RACT/BACT/LAER Clearinghouse
SNCR……………….selective non-catalytic reduction
SO_2……….………sulfur dioxide

SO_3………….………sulfur trioxide
SO_x………………….sulfur oxides
SOMP……………….Standard Operating and Maintenance Procedures
tpy…………………..tons per year
VOC………………...volatile organic compound

I. FACILITY DESCRIPTION

A. Site Description

The Somerset Power LLC site consists of approximately 40 acres of land situated in a mixed use area of Somerset, Massachusetts consisting of residential and commercial properties. The existing Somerset Power site includes approximately 140 megawatts (MW) net of coal, residual oil and jet fuel-fired electric power generation equipment. The site is bordered by County Street and Riverside Avenue to the west, the Taunton River to the east, residential properties and Annette Avenue to the north, and Stevens Street, a residential property and the Taunton River to the south.

The neighboring community consists of a mix of commercial and residential properties. The nearest residential areas are directly adjacent to the site to the north and south, and along the west side of Riverside Avenue.

B. Project Description

Somerset Power LLC Somerset Station is subject to 310 CMR 7.29 <u>Emissions Standards for Power Plants</u> that were promulgated on May 11, 2001 and amended effective June 4, 2004, October 6, 2006 and June 29, 2007. These regulations impose facility-wide annual emission limits for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2), and calendar month emission limits for NO_x and SO_2, in units of pounds per megawatt hour (lb/MWh), and annual emission limits for mercury (Hg) in units of pounds per gigawatt hour (lb/GWh) or a minimum Hg removal efficiency. These regulations do not impose carbon monoxide (CO) and fine particulate matter ($PM_{2.5}$) emission standards at this time, but development of such emission standards is reserved. These regulations required applicable power plants to submit an Emission Control Plan (ECP) that defined how the facility would comply with the 310 CMR 7.29 requirements. On June 7, 2002, the Department issued to Somerset Power LLC a Final Approval of the ECP and advised Somerset Power LLC of the requirement to receive a Plan Approval pursuant to 310 CMR 7.02 for the construction of the natural gas reburn project. On August 5, 2002, the Department received Somerset Power LLC's application requesting Plan Approval (4B02023) of the natural gas reburn project. In addition, although not required by 310 CMR 7.29, Somerset Power LLC submitted an application (4B02003) pursuant to 310 CMR 7.02 for modifications to the coal pile and construction of a fixed sound barrier along Riverside Avenue. On February 24, 2003, the Department issued Conditional Approvals (4B02003 and 4B02023) of the proposed natural gas reburn project and the fixed sound barrier and coal pile modifications.

On April 3, 2007, the Department received the Applicant's amended ECP application (4B06046) that requested approval to discontinue burning pulverized coal in Boiler 8 and to convert Unit 6/Boiler 8 to burn syngas. Revisions to the amended ECP application were received on April 13, 2007, and May 8, 2007. On _______, the Department issued an Amended Emission Control Plan Approval.

Proposed modifications to the Somerset Station include alterations to existing Unit 6/Boiler 8 coal fired electric utility generating unit. The proposed modifications will convert Boiler 8 from a conventional pulverized coal-fired boiler to a synthetic gas (syngas) fired boiler. Syngas will be produced by plasma gasification of coal and/or biomass feed stocks followed by a syngas cleanup train. The project will include the physical removal of the existing coal burners and pulverizers. Conversion of Unit 6/Boiler 8 to burn syngas will not result in any increase in potential to emit of any criteria air pollutant, and will significantly reduce annual emissions of NO_x, SO_2, PM (Particulate Matter), PM_{10} (Particulate Matter less than or equal to 10 microns in diameter) and $PM_{2.5}$ (Particulate Matter less than or equal to 2.5 microns in diameter) and lead (Pb). The conversion to syngas will result in reduced potential emissions of non-criteria air pollutants: hydrochloric acid (HCl), sulfuric acid (H_2SO_4), ammonia (NH_3) and Hg, and no increase in Hg emissions above the baseline in 310 CMR 7.02(3)(o)2: Table A. The project will also eliminate the production of bottom ash and fly ash, (which will be replaced by a saleable inert slag byproduct). A potential collateral increase in actual emissions of CO and VOC emissions may result from operation of the boiler after conversion to syngas; however, the applicant has demonstrated that any such increase would be less than "significant" emission thresholds under federal New Source Review (NSR) regulations. Although the rate of CO_2 (lb/MW-hr) from firing syngas is expected to be lower than the current emissions rate associated with pulverized coal combustion, a potential collateral increase in actual CO_2 emissions may result from the operation of the boiler after conversion to syngas if unit capacity factor were to increase in the future (CO_2 emissions estimates have been provided by the applicant at both current capacity factor and based on a hypothetical 10% increase in capacity factor from historical operations). The project does however, have the potential for an overall reduced CO_2 footprint in so far as it proposes to use certain biomass (renewable) feedstocks in place of coal (fossil fuel). A NO_x/CO/VOC optimization program after startup is proposed to ensure that the lowest overall emission levels will be achieved.

Somerset Power also proposes to construct an enclosed flare that will be used to vent syngas during emergency upset conditions and shutdowns, and for testing. Operation of the flare will be limited to not more than 500 hours per year after the project enters commercial operation (and no more than 1,000 hours per year during commissioning). Air emissions from the proposed emergency flare are addressed in the Best Available Control Technology (BACT) analysis section of this Conditional Approval.

The major components of the plasma gasification equipment, with the exception of the syngas emergency flare, will be located within the existing building. Limestone and coke will be stored in the existing coal storage area, and biomass will be stored in a converted existing oil tank or new enclosed storage building. The Applicant proposes to comply with 310 CMR 7.03(22) Conveyors, and Dry Material Storage (except silos) concerning biomass material storage and transfer conveyors.

C. Actual Emission Change Estimates

The construction/alteration of Unit 6/Boiler 8 to burn syngas (with or without the emergency flare emissions) are projected to reduce actual annual emissions of NO_x, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, Pb, CO_2, HCl, Hg and NH_3, and are projected to increase actual annual emissions of CO and VOC. The estimated actual emission changes are defined in Tables 1 through 3. Table 1 includes 1000 hours of flare operation, the limit for the first year of operation. Table 2 includes 500 hours of flare operation, the limit for all subsequent years. Table 3 includes no operation hours for the flare and reflects maximum projected boiler operation.

Table 1: ACTUAL EMISSION CHANGE ESTIMATES
(1st Year of Operation Including Maximum 1,000 hours of Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor, Boiler plus 1,000 hrs Flare[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor, Boiler plus 1,000 hrs Flare[1]	
		2004/05 Average	Projected Future	Net Change	Projected Future	Net Change
Fuel	MMBtu/yr	8,368,118	8,379,277	+11,159	9,217,205	+849,087
Net Output	kWh	795,587,000	749,719,685[2]	-45,867,315	824,691,653[2]	+29,104,654
Heat Rate	Btu/kWh	10,520	10,500[2]	-20	10,500[2]	-20
NO_x	tpy	962	299	-663	326	-636
CO	tpy	74.4	140	+65.6	153	+78.6
VOC	tpy	9.8	27.4	+17.6	30.4	+20.3
SO_2	tpy	4369	348	-4021	380	-3989
PM	tpy	100.5	64.4	-36.1	70.4	-30.1
PM_{10}	tpy	68.2	60.4	-7.8	66.4	-1.8
$PM_{2.5}$	tpy	68.2	60.4	-7.8	66.4	-1.8
H_2SO_4	tpy	43.1	13.5	-29.6	14.7	-28.4
Pb	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg	tpy	0.01	0.00089	-0.0091	0.00099	-0.0090
HCl	tpy	188.3	38.4	-149.9	42.0	-146.3
NH_3	tpy	52.4	41.1	-11.3	44.0	-8.4

Notes:
1 - Includes Unit 6/Boiler 8 with 1,000 hours of operation for the Emergency Syngas Flare
2 - Net Output and Heat Rate are for Unit 6/Boiler 8 only; the emergency flare generates no electricity

Table 2: ACTUAL EMISSION CHANGE ESTIMATES
(2nd Year and All Subsequent Years of Operation Including Maximum 500 Hours of Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor, Boiler plus 500 hrs Flare[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor, Boiler plus 500 hrs Flare[1]	
		2004/05 Average	Projected	Net Change	Projected	Net Change
Fuel	MMBtu/yr	8,368,118	8,632,887	+264,769	9,496,176	+1,128,058
Net Output	kWh	795,587,000	798,026,366[2]	+2,439,366	877,829,003[2]	+82,242,003
Heat Rate	Btu/kWh	10,520	10,500[2]	-20	10,500[2]	-20
NO_x	tpy	962	304	-658	334	-628
CO	tpy	74.4	142	+67.6	156	+81.6
VOC	tpy	9.8	26.2	+16.4	28.2	+18.4
SO_2	tpy	4369	356	-4013	390	-3979
PM	tpy	100.5	65.2	-35.3	71.2	-29.3
PM_{10}	tpy	68.2	61.2	-7.0	67.2	-1.0

$PM_{2.5}$	tpy	68.2	61.2	-7.0	67.2	-1.0
H_2SO_4	tpy	43.1	13.4	-29.7	14.7	-28.4
Pb	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg	tpy	0.01	0.00094	-0.0091	0.00104	-0.0090
HCl	tpy	188.3	39.2	-149.1	43.0	-145.2
NH_3	tpy	52.4	40.5	-11.9	44.5	-7.9

Notes:
1 - Includes Unit 6/Boiler 8 with 500 hours of operation for the Emergency Syngas Flare
2 - Net Output and Heat Rate are for Unit 6/Boiler 8 only; the emergency flare generates no electricity

Table 3: ACTUAL EMISSION CHANGE ESTIMATES
(No Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor[1]	
		2004/05 Average	Projected	Net Change	Projected	Net Change
Fuel	MMBtu/yr	8,368,118	8,886,497	+518,379	9,775,147	+1,407,029
Net Output	kWh	795,587,000	846,333,047	+50,746,047	930,966,351	+135,379,351
Heat Rate	Btu/kWh	10,520	10,500	-20	10,500	-20
NO_x	tpy	962	311	-651	342	-620
CO	tpy	74.4	144.6	+70.2	159.1	+84.7
VOC	tpy	9.8	24.2	+14.4	26.7	+16.9
SO_2	tpy	4369	364	-4,005	400	-3,969
PM	tpy	100.5	65.7	-34.8	72.3	-28.2
PM_{10}	tpy	68.2	61.3	-6.9	67.4	-0.8
$PM_{2.5}$	tpy	68.2	61.3	-6.9	67.4	-0.8
H_2SO_4	tpy	43.1	13.4	-29.7	14.7	-28.4
Pb	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg	tpy	0.01	0.00095	-0.0091	0.00104	-0.0090
HCl	tpy	188.3	40.1	-148.2	44.1	-144.2
NH_3	tpy	52.4	40.3	-12.1	44.3	-8.1

Notes:
1 - Annual operation of Unit 6/Boiler 8, assuming no Flare Events

D. Description of Proposed Alteration/Construction

The Applicant proposes construction/alterations to convert Unit 6/Boiler 8 to syngas as follows:

Unit 6/Boiler 8

Unit 6/Boiler 8 is a single reheat, pulverized coal-fired, balanced draft base load unit with a nominal 120 MW net output (132 MW gross output) generator capacity that began commercial operation in 1959. The actual net output of the Unit 6 turbine-generator has ranged to as low as 104 MW due in part to the fuel changes in order to comply with air pollution control regulations.

There will be no modifications to the existing Unit 6 generator as part of the syngas fuel conversion project.

Boiler 8 is a tangentially fired, Combustion Engineering boiler that currently utilizes pulverized coal as the primary fuel and No. 6 fuel oil as a secondary fuel. Boiler 8 is presently limited to 1,186 million Btu per hour (MMBtu/hr) heat input. The boiler is capable of supplying 800,000 pounds of steam per hour at 1,925 pounds per square inch gauge (psig) and 1,000 ^{o}F to Unit 6 turbine-generator. Boiler 8 is equipped with a natural gas reburn system and NOX-OUT Selective Non-catalytic Reduction (SNCR) post combustion NO_x emission controls that operates in conjunction with the natural gas reburn system to reduce NO_x emissions. Boiler 8 is also equipped with an electrostatic precipitator (ESP) for the control of particulate matter. Products of combustion are released to the ambient air from a stack 310 feet above ground level with an inside diameter of 156 inches.

Boiler 8 will be converted to burn syngas as the primary fuel. The existing coal pulverizers and burners will be removed and new low NO_x design syngas burners will be installed with a new burner management system. Substantial economizer, superheater, and likely waterwall modifications will be required to optimize heat transfer and heat adsorption when burning syngas to match the steam capacity of the Unit 6 turbine-generator and to optimize efficiency. These modifications are necessary since syngas burns with a bluish transparent flame at temperatures much lower than pulverized coal combustion and heat transfer will be primarily convective, versus primarily radiant heat transfer with pulverized coal burning that produces a hotter white-yellow flame. Up to 10% of the boiler heat input will be provided by oil (or biodiesel) having a sulfur content of 0.3% by weight or less, to ensure flame stabilization and system safety.

The existing natural gas reburn system and existing ESPs will be removed or abandoned in place; the existing SNCR system will be retained and operated as needed for NO_x emission control; and the existing stack will be retained. In addition, existing Boilers 1 through 6 and ancillary equipment will be removed as required to create indoor space for the plasma gasification equipment and syngas cleanup train.

<u>Plasma Gasification Equipment</u>

Westinghouse Plasma Corporation (or equivalent) gasification system technology will be utilized and it will represent the first known commercial application of direct coal plasma gasification. The plasma system will consist of up to four gasifiers. Each gasifier consists of a steel and ceramic cupola with plasma torches (typically six per cupola) that will create a very high temperature plasma zone in the bottom of the cupola. Up to 10% of the heat input to the gasifier will be in the form of metallurgical coke, which will establish a bed of carbon at the bottom of the gasifier to support the gasification zone of coal and/or biomass gasification feedstocks. Up to 35% of the annual feedstock consumption may be biomass feedstocks consisting of wood, wood chips, agricultural solid products, and/or other biomass derived feedstock [non-recyclable paper (paper cubes) and/or processed construction and demolition derived feedstock, etc.] approved by the Department through a Beneficial Use Determination pursuant to 310 CMR 19.060. Air (air blown or oxygen enriched) will be blown through the plasma torches heating it to approximately 10,000 ^{o}F converting the air to a plasma state. This plasma is injected into the gasification bed that will operate at approximately 6,000 ^oF. The gaseous stream rises to the top of the cupola almost completely dissociating the feedstock (coal, biomass and coke) into two streams: gaseous organic material and inorganic liquid (melted ash). Limestone is fed to the gasifiers as needed to flux the liquid slag; however it is otherwise an inert material. The main combustible constituents of the syngas consist primarily of carbon monoxide (CO) and hydrogen (H_2). The inorganic liquid stream is an inert vitrified mineral slag consisting of melted ash constituents. The vitrified mineral slag will be maintained in a hot molten state and will be drained via a port on the bottom of the cupola to a water quench, where it will harden and shatter to an inert solid material similar to crushed glass.

The gasifiers will operate under a slight negative pressure to preclude any fugitive emissions. Syngas will exit the gasifier at approximately 1,900 ^oF at a low velocity in order to minimize carry over of solid particulate to the syngas cleanup train.

<u>Synthetic Gas (Syngas) Cleanup Train</u>

The syngas cleanup train will consist of a syngas cooler, wet quench scrubber, baghouse, polishing wet scrubber, carbon filters and aqueous contactors/bioreactors. There will be no syngas bypasses installed on any component of the syngas cleanup train.

The syngas cooler will consist of one heat exchanger that will reduce syngas temperature to approximately 500 ^oF. Steam produced will be used in the Unit 6/Boiler 8 steam and/or feedwater cycle. The cooled syngas will enter a wet quench spray scrubber designed to remove HCl, SO_2 and NH_3 and to further cool the syngas prior to entering a baghouse (fabric filter) for fine particulate removal. The baghouse is designed with nitrogen pulse bag cleaning and particulate captured is recycled back to the cupolas. Syngas exiting the baghouse passes through a polishing wet scrubber to further condense aerosols and remove residual acid gases, filterable particulate and condensable particulate. Syngas then passes through a syngas blower prior to entering a two-stage fixed bed activated carbon filter for elemental Hg removal. A Hg sampling location will be provided between the two carbon beds to periodically monitor for Hg break-through that will identify the need to replace carbon in the lead bed. It is estimated that one carbon bed saturated with Hg will need to be changed out and disposed every other year. Syngas exiting the carbon beds passes through a Shell Paques (or equivalent) system for H_2S removal consisting of one or more packed-bed scrubbers that uses an aqueous soda solution containing thiobacillus bacteria. The soda solution absorbs the H_2S and is then circulated through one or more aerated atmospheric bioreactor tanks where the bacteria will convert the scrubbed H_2S to elemental sulfur. The sulfur solution is dewatered and may be reused for agricultural fertilizer or a high quality (99%+) sulfur cake may be produced for sale. The clean syngas exiting the packed bed scrubbers is ducted to the Boiler 8 syngas burners, or in case of an upset condition, such as a Boiler 8 emergency burner trip, the clean syngas will be diverted to the emergency syngas flare to shutdown the process. The syngas is expected to have a higher heating value of approximately 150 Btu/ft^3.

Emergency Syngas Flare

An enclosed syngas flare will combust residual clean syngas during an upset condition such as an emergency burner trip. Products of combustion will be released to the ambient air from a stack 80 feet above ground level (96.4 feet above sea level) with an inside diameter of 32 feet. The base of the syngas flare will include a masonry sound barrier to reduce sound impacts when the flare is in operation.

II. EMISSIONS

A. Background

Boiler 8 currently burns coal and No. 6 fuel oil and will in the future burn syngas with up to 10% oil (or biodiesel) having a sulfur content of 0.3% by weight or less. Emissions to the ambient air from Boiler 8 operation include the criteria air contaminants PM, PM_{10}, $PM_{2.5}$, SO_2, CO, NO_x, Pb and VOC and the non-criteria air contaminants H_2SO_4, HCl, Hg and NH_3. With the conversion of Boiler 8 to syngas firing, all air contaminant potential to emit (PTE) emission rates to the ambient air will decrease.

B. New Emission Limits

1. Unit 6/Boiler 8 shall not exceed the emission limits as specified in Table 4:

Table 4: UNIT 6/BOILER 8 EMISSION LIMITS

Emission	lb/MMBtu		ppmvd @ 3% O_2		lb/hr	tpy[f]
	1-hr Avg.	30-day avg.[c]	1-hr avg.	30-day avg.[c]		
NO_x[a]	0.367	0.07	255	54.7	471	393.7
CO[a]	0.083	0.033	95	37.2	107	183.0
VOC[a,b]	0.0073	0.005	14.6	11.2	9.37	30.7
SO_2[a]	1.2	0.08	-	-	1541	460.0
PM	0.015	-	-	-	103	83.1
PM_{10}	0.014	-	-	-	103	77.5
$PM_{2.5}$	0.014	-	-	-	103	77.5
H_2SO_4	0.003	-	-	-	3.85	16.9
Pb	0.00039	-	-	-	0.501	2.2
Hg[d,e]	2.4E-07	2.4E-07	-	-	3.1E-04	1.3E-03
HCl	0.0090	-	-	-	11.6	44.1
NH_3	0.0091	-	17	-	10.1	50.9

Note:

a - Based upon stack compliance emission testing per 40 CFR 60.8, or as otherwise approved by the Department, and continuous emission monitor (CEM) data

b - Based upon CO CEM emission data correlated to VOC emissions

c - Based on a 30-day rolling average

d - Hg emissions will meet the MA 7.29 requirements – 7.5 x 10^{-6} lb/MWh (7.1 x 10^{-7} lb/MMBtu) during the first year and prior to commercial operation which is prior to the date the Applicant notifies ISO New England, Inc. that Unit 6/Boiler 8 is released for commercial generation dispatch with the syngas conversion equipment in continuous operation.

e - Based on 95% reduction from typical Hg in coal and EPA AP42 factors.

f - tpy is tons per consecutive twelve month period.

2. Unit 6/Boiler 8 shall not exceed the emission limits/standards as specified in Table 5:

Table 5: EMISSION LIMITS/STANDARDS[a]	
NO_x	0.735 lb/MWh (calculated over any 12 month period, recalculated monthly) 0.735 lb/MWh (calculated over any individual month)
SO_2	0.84 lb/MWh (calculated over any 12 month period, recalculated monthly) 0.84 lb/MWh (calculated over any individual month)
Hg	95% control or 0.0025 lb/GWh (calculated over any 12 month period, recalculated monthly)[b]

Note:
a - Methodology to demonstrate compliance shall be in accordance with procedures contained in 310 CMR 7.29 Emissions Standards for Power Plants or alternative monitoring as approved by the Department.
b - Unit 6/Boiler 8 shall achieve the 2012 310 CMR 7.29 limits upon achieving commercial operation.

3. Somerset Power LLC shall perform a NO_x/CO/VOC optimization/minimization program prior to compliance emission testing.
4. The Department reserves the right to reduce CO and/or VOC emission limits to less than the above based upon compliance emission test results achieved, the optimization/minimization program and CEM data.
5. The Unit 6/Boiler 8 start up requirements pertaining to NO_x and CO emissions contained in Section VI – Special Conditions of the September 29, 1998 NO_x Reasonably Available Control Technology (RACT) ECP Approval (4B95165) remain in effect.
6. Unit 6/Boiler 8 and the Emergency Syngas Flare shall not exceed 20 percent opacity for a period or aggregate period of time in excess of two minutes during any one hour provided that, at no time during the said two minutes shall the opacity exceed 40%.
7. The Emergency Syngas Flare shall not exceed the emission limits as specified in Table 6:

Table 6: EMERGENCY SYNGAS FLARE EMISSION LIMITS				
Emission	**lb/MMBtu[a]**	**lb/hr[a]**	**tpy[b,c]**	**tpy[b,d]**
NO_x	0.07	89.9	22.5	11.2
CO	0.037	47.5	11.9	5.9
VOC	0.02	25.7	6.4	3.2
SO_2	0.08	103	25.7	12.8
PM	0.02	25.7	6.4	3.2
PM_{10}	0.02	25.7	6.4	3.2
$PM_{2.5}$	0.02	25.7	6.4	3.2

Note:
a - Based upon stack emission testing per 40 CFR 60.8, or as otherwise approved by the Department, and based on the average of three 1-hr tests. Lb/MMBtu and lb/hr limits for the emergency flare are based on maximum 1-hr emission levels, assuming operation at 1284 MMBtu/hr for an entire hour.
b - tpy is tons per consecutive twelve month period, and are based on average syngas flow rate over each shutdown event of 642 MMBtu/hr (1,284 MMBtu / 2).
c - Prior to commercial operation - maximum 1,000 hr/yr and 642,000 MMBtu/yr input
d - Post commercial operation - maximum 500 hr/yr and 321,000 MMBtu/yr input

8. Unit 6/Boiler 8 and the Emergency Syngas Flare will become subject to Table 4: Unit 6/Boiler 8 Emission Limits, Table 5: Unit 6/Boiler 8 Emission Limits/Standards, and Table 6: Emergency Syngas Flare Emission Limits as of the date specified in Section XI.4.e., but not later than 180 days after initial burning of syngas.

III. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW

A. Background

The federal government under the jurisdiction of the Environmental Protection Agency (EPA) established National Ambient Air Quality Standards (NAAQS) for seven air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2, PM_{10}, $PM_{2.5}$, NO_2, CO, ozone (O_3), and Pb.

One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of existing and new sources, complies with ambient standards. Towards this end, EPA classified all areas of the country as “attainment,” “nonattainment” or “unclassified” with respect to the NAAQS.

New major stationary sources of regulated air pollutants or major modifications to existing major stationary sources of regulated air pollutants that are located in areas classified as either “attainment” or “unclassified” are subject to 40 CFR Section 52.21 Prevention of Significant Deterioration of Air Quality (PSD) regulations. Pursuant to 40 CFR 52.21(b)(1)(i)(a), a source is considered “major” if it has the potential to emit 100 tpy or more of any regulated NSR pollutant and is listed as one of the 28 designated PSD stationary source categories, and a modification is considered a “major modification” if the physical change or change in the method of operation of a “major” stationary source would result in a significant net emission increase.

Effective July 1, 1982, the PSD program was implemented, by the Department, in accordance with the Department's “Procedures for Implementing Federal Prevention of Significant Deterioration Regulations.” Somerset Power LLC, Unit 6/Boiler 8, steam to electric power generation unit is rated at 1,284 MMBtu/hr heat input. Thus, Somerset Station is one of the 28 designated PSD stationary source categories, namely a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input and is an existing major stationary source of regulated air pollutants.

Effective March 3, 2003, the Department notified US EPA Region 1 that Massachusetts would no longer implement the PSD program and returned delegation of the PSD program to the US EPA. Therefore, the US EPA Region 1 has the responsibility to determine PSD applicability for this project.

B. General Information

The Applicant is proposing to alter Unit 6/Boiler 8 at its electric utility steam generating facility in Somerset, Massachusetts. The facility is located in an area that is in either “attainment” or “unclassified” for SO_2, NO_2, CO, Pb, PM_{10} and $PM_{2.5}$. Therefore, the facility is located in a PSD area for these pollutants.

IV. EMISSION OFFSETS AND NONATTAINMENT REVIEW

A. Background

The entire Commonwealth of Massachusetts is designated "moderate" nonattainment (NA) for the pollutant O_3 NAAQS. NO_x and VOCs emissions are precursors to the formation of O_3.

New major stationary sources of regulated air pollutants or major modifications to existing major stationary sources of regulated air pollutants that are located in areas classified as "nonattainment" are subject to 310 CMR 7.00: Appendix A Emission Offsets and Nonattainment Review. Pursuant to 310 CMR 7.00: Appendix A(2), a source is considered "major" if it has a potential to emit 50 tpy or more of NO_x or VOC, and a modification is considered a "major modification" if the physical change or change in method of operation of a "major" stationary source would result in a significant net emission increase. A significant net emission increase for applications received after November 15, 1992 is defined as 25 tpy of either VOC or NO_x emissions.

Applicable requirements for any proposed new major stationary source of NO_x and/or VOC require the source to meet Lowest Achievable Emission Rate (LAER) and obtain emission offsets.

B. General Information

Alteration of Unit6/Boiler 8 is not categorized as a "major modification" to an existing major source since the alteration would not result in a representative actual annual emissions increase in excess of the NSR significant emission increase thresholds.

2004-2005 Average Past Actual Baseline

For the alterations proposed in NMCPA (4B06046) submitted on December 22, 2006, the NO_x and VOC net emission change estimates for Unit 6/Boiler 8 for emissions subject to Nonattainment review are defined in Table 7.

Table 7: NONATTAINMENT REVIEW

		Actual Emissions		Baseline Emissions	Projected Emissions with Syngas[a]	Net Emission Change		
		Emissions 2004	Emissions 2005	2004/05 Average	Representative Actual Annual Emissions	(Projected) -(Baseline)	NA Significance Threshold	NA Significant (Y/N)
NO_x	tpy	972.5	951.4	962	334	-628	25	No
VOC	tpy	9.9	9.6	9.8	28[b]	+18.2[b]	25	No

Note:
a - Includes Unit 6/Boiler 8 and the Emergency Syngas Flare
b - 1st year of syngas operation 30 tpy and a +20.2 tpy net emission change

The syngas conversion project, based on comparing past actual annual emissions to future representative actual annual emissions, will result in significant NO_x emission reductions, and less than a significant net increase in representative actual emissions of VOC. Unit 6/Boiler 8 collateral VOC representative actual emissions increase will not adversely affect NAAQS for O_3 due to the substantial reductions of NO_x emissions.

C. Conclusion

The proposed Unit 6/Boiler 8 alteration, based on current information and pursuant to 310 CMR 7.00: Appendix A(2), is not considered a "major modification" to an existing major stationary source. Based on current information, LAER and Offsets, pursuant to 310 CMR 7.00: Appendix A, are not required for the alterations/construction. Refer to Section X and XI for emission record keeping and reporting requirements.

V. NEW SOURCE PERFORMANCE STANDARDS

A. Background

The New Source Performance Standards (NSPS) for fossil fuel-fired steam generators and electric utility steam generating units, are contained in Title 40 Part 60 Subpart D and Subpart Da, respectively. Unit 6/Boiler 8 is considered to be a "fossil fuel-fired steam generating unit" and an "electric utility steam generating unit" since Unit 6/Boiler 8 burns fossil fuels at a rate greater than 250 MMBtu/hr and more than one third of Unit 6 net electrical output will be sold to a utility.

The Applicant has acknowledged that the Unit 6/Boiler 8 syngas conversion project, including the plasma gasification syngas production process, will likely meet the test of "reconstruction," as defined in 40 CFR 60, since the costs likely meet 50% of the replacement cost test that would constitute "reconstruction."

B. Conclusion

The NSPS for fossil fuel-fired steam generators and electric utility steam generating units, Title 40 Part 60 Subpart D and Subpart Da, respectively, of the Code of Federal Regulations (the NSPS), are applicable to Unit 6/Boiler 8. This Conditional Approval includes emission limits, monitoring, recordkeeping and reporting requirements in compliance with the NSPS. Compliance with this Conditional Approval means compliance with the NSPS.

VI. BEST AVAILABLE CONTROL TECHNOLOGY

Pursuant to 310 CMR 7.02(3)(j)6., the Applicant is required to evaluate Best Available Control Technology (BACT) as it applies to any air contaminant that will result in a potential emission increase. Boiler 8 conversion to syngas will result in no potential emission increase of any air contaminant. As a new emission source, the proposed emergency flare is subject to the application of BACT for all emissions with a potential to emit of 1 tpy or more. BACT is defined as an emission limitation using the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The proposed flare must utilize BACT to control NO_x, CO, VOC, SO_2, PM, PM_{10}, and $PM_{2.5}$ emissions. The Department has verified and concurs with the following Comparative BACT Analysis (as referenced in the Applicant's NMCPA).

No precedents for burning plasma gasification syngas during shutdown events in an enclosed flare were identified through the RACT/BACT/LAER Clearinghouse (RBLC) or other background research. The most similar existing sources are enclosed flares at petroleum refineries or landfills firing low-Btu petroleum or landfill gas. In these cases, good (optimized) combustion is the only identified control technology. The Mid-Atlantic Regional Air Management Association (MARAMA) published a model rule for emissions from petroleum refinery flares in October of 2006. BACT emission rates for the emergency syngas flare were based on the emission rates in the MARAMA rule, emission rates of existing petroleum and landfill gas flares in the RBLC, and engineering judgment.

Therefore, based upon the economic analysis portion of the top-down BACT process, currently available data, and the tenets and procedures of the BACT process, the Department has concluded that the use of clean syngas, operational restrictions to 1,000 hours for the first year of operation and 500 hours per year for all subsequent years, and good combustion control are the only technically feasible means to achieve BACT emission rates for the proposed emergency flare.

The BACT combustion controls consist of design and operation of the flare in a manner so as to limit NOx, VOC and CO formation. Combustion control systems seek to maintain the proper conditions to ensure complete combustion through operational design that provides sufficient residence time, excess air, good mixing and staged combustion to completely burn out products of incomplete combustion (VOC and CO).

VII. SOUND

A. Background

The Department regulation concerning sound emissions is contained in 310 CMR 7.10 Noise. This regulation requires that necessary equipment and precautions be used to prevent a condition of air pollution due to sound emissions from the facility. The Department's existing guideline for enforcing the noise regulation is contained in the Department's Policy 90-001; the policy provides broadband and pure tone sound level criteria.

The Somerset Power LLC facility sound impacts were extensively evaluated at the time of the conversion to coal in the 1980's. Sound emissions and control requirements for the coal conversion are contained in the Department's December 11, 1986 Plan Approval (SM82-084-CO, SM83-021-CO, SM-83-022-CO, SM83-094-CO, SM-84-036-CO and SM84-043-M) and remain in effect other than the requirements concerning the design, operation and maintenance of the inactive coal pile. The Department's approval (4B02003), dated February 24, 2003, of the sound barrier wall in lieu of the inactive coal pile remains in effect.

Based upon a records review, the existing facility has not caused a condition of air pollution due to sound emissions since the coal conversion in the 1980's. Offsite sound from major facility sources has been controlled using buildings to enclose stationary equipment, and, recently, by constructing a barrier wall along Riverside Avenue to control sound emissions from the coal handling operations and further reduce overall facility sound impacts toward residences southwest of the facility. The effectiveness of the barrier wall is detailed in a compliance test report letter to MassDEP from Somerset Operations, Inc. on November 25, 2003, and final approval of the sound wall was provided by MassDEP on March 7, 2005.

It is predicted that the sound emissions from the syngas conversion project will result in no perceptible increase in sound [no increase greater than 3 dB(A) will occur] in the adjacent residential areas. Facility buildings will continue to control sound emissions from stationary equipment, and the sound wall will continue to act as a barrier to the receptors southwest of the facility along Riverside Avenue. Several existing sources of sound emissions will be discontinued, including the existing coal pulverizers and ash handling system. Sound emissions from most of the new equipment will be attenuated by enclosure within existing buildings or structures. The proposed ground flare represents a new potential noise source adjacent to the existing building on the North side of the Station. The flare sound emissions were evaluated for potential impacts to the nearest residential receptor (along the north side of Annette Avenue), and was shown to result in no perceptible sound increase [i.e., < 3 dB(A)] at that location. Sound from the emergency ground flare is broadband sound (not tonal) and will be minimized by a concrete sound wall surrounding the flare. The flare design will be specified to meet a sound level at 100 feet from the flare of 61 dB(A) or less, which is predicted to result in no perceptible increase in sound at the nearest residential receptor. The emergency ground flare specification of 61 dBA or less at 100 feet is based on the following:

- existing nighttime sound levels measured at the nearest two residences on May 2007;
- estimated flare sound levels from published empirical equations for flare noise;
- acoustical modeling of estimated flare sound levels to the nearest residential receptors; and
- results of the May 2007 measurements of existing sound, estimated flare sound levels and predicted emergency flare sound at the nearest residential receptors (MassDEP form BWP AQ SFP-3) are presented in Appendix D.

B. General Information

Sound Mitigating Measures

1. All components of the plasma gasification equipment and syngas cleanup train (the main sources of sound) are located within the existing power plant building
2. The Conditional Approval (4B02003) by the Department, dated February 24, 2003, concerning the sound barrier wall will remain in effect. This sound barrier wall mitigates the facility sound impacts from the coal receipt and handling in the South Yard.
3. The Emergency Syngas Flare will be located in the North Yard. A concrete sound wall will surround the flare to reduce sound when the flare is in operation.
4. The new biomass / materials storage and handling facilities which will be located across Riverside Ave, will be largely passive and rotating equipment will be shielded within the

enclosure(s). Biomass delivery trucks will deliver to the site 6 days a week between the hours of 7:00 a.m. and 7:00 p.m.

C. Conclusion

Sound impacts due to the Unit 6/Boiler 8 syngas conversion project will result in no perceptible ambient increase in sound impacts at adjacent residential areas. Sound impacts proposed in the application meet the requirements contained in 310 CMR 7.10 Noise and will not cause or contribute to a condition of air pollution.

Somerset Power LLC shall conduct a sound survey within 60 days from the date Unit 6/Boiler 8 is available for commercial operation (as defined by ISO New England, Inc.) with the syngas in continuous operation. A report shall be submitted to the Department, within 30 days after the sound survey, defining actual sound impacts in comparison to impacts proposed in the application approved herein.

VIII. SPECIAL CONDITIONS

1. The Applicant shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(5)(c), updated completed Department NMCPA application forms, plans, specifications for Boiler 8 modifications, Plasma Gasification Equipment, Syngas Cleanup Train and Emergency Syngas Flare not later than 30 days prior to commencement of construction/installation.
2. Pursuant to Regulation 310 CMR 7.00: Appendix C and the November 7, 1995 US EPA letter to State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officers (STAPPA/ALAPCO) (now National Association of Clean Air Agencies, NACAA), the modification approved herein will be a “Minor Modification” to Operating Permit 4V95057 since this Conditional Approval (Application No. 4B06046) is a minor NSR action. An Operating Permit Minor Modification application shall be submitted to the Department on or before the commencement of the alterations/construction that reflects the Amended ECP Final Approval (4B07009), this Conditional Approval (Application No. 4B06046), and any other applicable requirement that the facility is subject to.
3. The Applicant shall submit Standard Operating and Maintenance Procedures (SOMP) for the new equipment to the Department no later than 60 days after commencement of operation of the proposed facility. Thereafter, the Applicant shall submit updated versions of the SOMP to the Department no later than 30 days prior to the occurrence of a significant change. The Department must approve in writing any significant changes to the SOMP prior to the SOMP becoming effective.
4. The Applicant shall submit a revised SOMP to the Department, within 12 months of the date specified in Section XI.4.e. that addresses NOx/CO/VOC minimization/optimization and NH_3 slip minimization.
5. The Applicant shall, within 60 days after the submittal to the Department of the compliance test report, propose a surrogate methodology or parametric monitoring for NH_3 emissions based on compliance test results and operating experience.

6. The Applicant shall maintain a complaint log concerning emissions, odor, dust and noise from the facility. The Applicant shall make available to the general public a telephone number that will receive and record complaints 24 hours per day, 7 days per week. The complaint log shall be maintained for the most recent five (5) year period. The complaint log shall be made available to the Department upon request. The Applicant shall take all reasonable actions to respond to complaints.
7. The Applicant, within 12 months of the date specified in Section XI.4.e., shall propose new CO and VOC emission limits for Unit 6/Boiler 8, and provide supporting justification for the new proposed emission limits taking into consideration the NO_x/VOC/CO optimization/minimization program emission test data, compliance emission test data, CO CEM data and operating experience. The Department will establish final CO and VOC emission limits after review of the Applicant's proposed final emission limits and supporting documentation. The goal of the program is to achieve CO emissions of 20 ppm_{vd} @ 3% O_2 or less.
8. The Applicant shall promptly undertake a reasonable and appropriate study of NH_3 slip from Unit 6/Boiler 8 and upon the completion of the study develop and implement an emission optimization plan that gives due consideration to minimizing ammonia slip.
9. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.48Da Compliance Provisions and within 45 days prior to burning syngas in Unit 6/Boiler 8 submit to the Department the Applicant's plan to meet the requirements therein.
10. Unit 6/Boiler 8 shall cease burning pulverized coal and shutdown for the conversion to syngas on or before January 1, 2010.

IX. MONITORING AND RECORDING REQUIREMENTS

1. All current monitoring and recording requirements remain in effect and are not altered herein.
2. The Applicant shall ensure continuous monitoring and compliance with VOC emission limits utilizing the CO parametric monitoring methodology developed during the initial compliance test.
3. If CO emissions are below the CO emission limit, the VOC emissions shall be considered as meeting the emission limits contained in this Conditional Approval, subject to correlation as contained in Condition IX.4., below.
4. If CO emissions are above the CO emission limit, the VOC emissions shall be considered as occurring at a rate determined by the equation: $VOC_{actual}=VOC_{LIMIT}\ x(CO_{actual}/CO_{limit})$, pending the outcome of the initial compliance testing, after which a VOC/CO correlation curve and/or emission factors for Unit 6/Boiler 8 will be developed and used for VOC compliance determination purposes.
5. Unit 6/Boiler 8 shall meet 40 CFR Part 75 Continuous Emission Monitoring requirements, as applicable.
6. Unit 6/Boiler 8 shall be equipped with an NH_3 CEM within 180 days after the end of any consecutive 12-month period recalculated monthly during which the Boiler 8 SNCR system is utilized for 2,000 hours or more. Once this 2,000 hour SNCR operational trigger is reached in any consecutive period of 12 months, the requirement to maintain the NH_3 CEM will remain in effect even if the use of the SNCR decreases to less than

2,000 hours in subsequent consecutive 12-month periods. If a NH_3 CEM is required on Boiler 8, it shall be certified within 60 days of installation.

7. If the NH_3 CEM is required on Boiler 8, the NH_3 monitor upon certification will be used as direct compliance level monitor. The NH_3 CEM shall comply with the CEM linearity check and Relative Accuracy Test Audit (RATA) frequencies and grace periods specified in 40 CFR 75 in conducting linearities and RATAs. The relative accuracy of the NH_3 CEM systems shall be within the greater of +/- 15% or +/- 0.75 ppm_{vd} @ 3% O_2 or +/- 0.0004 lb/MMBtu or lb/hr = +/- 0.0004 lb/MMBtu x WA_MMBtu/hr, where WA_MMBtu/hr = the weighted average MMBtu/hr determined by the DAHS over the hours during which the RATA was performed. The NH_3 CEM shall obtain valid data for at least 90% of the hours per calendar quarter during which the emission unit is operating.

8. In the event that a given NH_3 CEM RATA does not meet the relative accuracy specified in IX.7., the following shall apply:
   a. Somerset Power LLC shall investigate the possible reasons for a RATA failure and whether repairs or adjustments are necessary for the NH_3 CEM or its sampling location/path. If such NH_3 CEM repairs or adjustments are necessary prior to a successful RATA, or if sampling location/path adjustments are required, then the NH_3 CEM data shall be considered invalid from the time of the failed RATA until a successful RATA occurs.
   b. If no repairs or adjustments to the NH_3 CEM are necessary between the time of a failed RATA and a successful RATA, and no sampling location/path adjustments are needed, then the NH_3 CEM data shall be considered valid during the period between the failed RATA and successful RATA.

9. In the event data from a NH_3 CEM is not available, corrective action shall be implemented as quickly as practical to bring the NH_3 CEM back to service. During the time when the NH_3 CEM is not available, Somerset Power LLC may submit a parametric monitoring methodology to the Department for approval to provide assurance that the NO_x levels, operating loads, and urea injection rates being maintained are consistent with prior urea-compliant operation.

10. At least 60 days prior to commencing construction of the NH_3 CEM systems, the NH_3 CEM monitoring plan shall be submitted to the Department for review and approval. The NH_3 CEM monitoring plan shall include:
    - Source identification
    - Source description
    - Control technology description
    - Applicable regulations
    - Type of monitor
    - A monitoring system flow diagram
    - A description of the data handling system
    - A sample calculation demonstrating compliance with the emission limits using conversion factors from 40 CFR 60 or approved by the Department

11. In the event that an NH_3 CEM is required, the NH_3 CEM system certification protocol shall be submitted to the Department at least 60 days prior to certification testing for the CEM.

12. In the event that an NH_3 CEM is required, the NH_3 CEM system certification report shall be submitted to the Department within 45 days from the completion of testing.
13. The applicant shall comply with 40 CFR 60, Subpart Da, Section 60.49Da Emission Monitoring and within 45 days prior to burning syngas in Unit 6/Boiler 8 submit to the Department the Applicant's plan to meet the requirements therein.

X. RECORD KEEPING REQUIREMENTS

1. A record keeping system for the proposed facility shall be established and maintained on site by the Applicant. All such records shall be maintained up-to-date such that year-to-date information is readily available for Department examination upon request and shall be kept on-site for a minimum of five (5) years. Record keeping shall, at a minimum, include:
   a) Compliance records sufficient to demonstrate that emissions from the facility have not exceeded that allowed by this Proposed Conditional Approval. Such records shall include, but are not limited to, fuel usage data, emissions test results, monitoring equipment data and reports.
   b) Maintenance: A record of routine maintenance activities performed on the proposed control equipment and monitoring equipment including, at a minimum, the type or a description of the maintenance performed and the date and time the work was completed.
   c) Malfunctions: A record of all malfunctions on the proposed Unit 6/Boiler 8 control and monitoring equipment including, at a minimum: the date and time the malfunction occurred; a description of the malfunction and the corrective action taken; the date and time corrective actions were initiated; and, the date and time corrective actions were completed and the proposed equipment was returned to compliance.
2. The Applicant shall maintain on-site for five (5) years all records of output from all continuous monitors for flue gas emissions and fuel consumption, and shall make these records available to the Department upon request.
3. The Applicant shall maintain a log to record upsets or failures associated with the proposed emission control systems.
4. The applicant shall maintain records of the urea consumption per day, per month and on a 12-month rolling period.
5. The applicant shall maintain records of the operating hours of the emergency flare per day, per month and on a 12-month rolling period.
6. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.52Da Recordkeeping Requirements.

XI. REPORTING REQUIREMENTS

1. All notifications and reporting required by this Conditional Approval shall be made to the attention of:

Department of Environmental Protection
Bureau of Waste Prevention
20 Riverside Drive
Lakeville, Massachusetts 02347
ATTN: Permit Section
Telephone: (508) 946-2770
Fax: (508) 947-6557 or (508) 946-2865

2. Pursuant to 310 CMR 7.00: Appendix A, Somerset Power LLC on an annual basis for a period of 5 years from the date the unit resumes regular operation with the syngas as a fuel, shall submit information demonstrating that the physical or operational change (conversion to syngas) did not result in an emission increase beyond the "representative actual annual emissions" defined in Section IV Emission Offsets and Nonattainment Review. Should there be an increase beyond that defined in Section IV, the Department will consider information provided by Somerset Power LLC that the increase is unrelated to the conversion to syngas, such as, any increased utilization due to the rate of electricity demand growth for the utility system as a whole.
3. Somerset Power LLC shall notify the Department by telephone or fax as soon as possible but no later than three (3) business days after the occurrence of any upset or malfunction to the facility equipment, air pollution control equipment, or monitoring equipment which results in an emission to the ambient air in excess of that approved herein and/or a condition of air pollution.
4. Somerset Power LLC shall notify the Department in writing within 10 days after each activity listed below occurs:
   a) The date construction commences on the syngas conversion equipment.
   b) The date syngas conversion equipment construction is completed.
   c) The date syngas is first burned in Boiler 8 and the flare.
   d) The date Unit 6/Boiler 8 attains the maximum production rate.
   e) The date of notification to ISO New England, Inc. that Unit 6/Boiler 8 is released for commercial generation dispatch with the syngas conversion equipment in continuous operation.
5. The applicant shall submit NH_3 CEM Excess Emission Reports for each calendar quarter by the thirtieth (30^{th}) day of April, July, October, and January covering the previous calendar periods of January through March, April through June, July through September, and October through December, respectively, in the event that an NH_3 CEM system is required by Condition IX.6..
6. The applicant shall submit an annual NH_3 CEM Emission Report by January 30^{th} that defines highest hourly average NH_3 emissions (ppm_{vd} corrected to 3%O_2) per calendar day and the average calendar day NH_3 emissions (ppm_{vd} corrected to 3%O_2), in the event that an NH_3 CEM system is required by Condition IX.6..
7. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.51Da Reporting Requirements.

XII. TESTING REQUIREMENTS

1. The Applicant shall ensure that the proposed facility (Boiler and flare) is constructed to accommodate the emissions (compliance) testing requirements contained herein. All emissions testing shall be conducted in accordance with the Department's "Guidelines for Source Emissions Testing" and in accordance with the Environmental Protection Agency reference test methods as specified in 40 CFR Part 60, Appendix A, or as otherwise approved by the Department.
2. The applicant shall conduct a NO_x/VOC/CO optimization/minimization emission test program and submit the final test report to the Department at least 30 days prior to the start of emission compliance testing. Special attention shall be given to assure the VOC test method parameters will provide samples that will be within the detection limit of the actual VOC emission levels. Preliminary VOC emission testing shall be conducted prior to the optimization/minimization emission test program to assure results will be within the detection limit during the optimization/minimization test program.
3. The Applicant shall conduct initial emission compliance tests no later than 60 days after achieving the maximum production rate at which Unit 6/Boiler 8 will operate, but not later than 180 days after the initial startup on syngas of Unit 6/Boiler 8. The emission compliance test program shall comply with the Department's "Guidelines for Source Emission Testing."
4. The Applicant must obtain written Department approval of an emissions test protocol. The protocol shall include a detailed description of sampling port locations, sampling equipment, sampling and analytical procedures, and operating conditions for any such emissions testing. It must be submitted to the Department at least 30 days prior to commencement of testing of the facility.
5. The Applicant shall ensure that a final emissions test results report is submitted to the Department within 60 days of completion of the emissions testing program.
6. The Applicant shall conduct emission tests to demonstrate that Unit 6/Boiler 8 is in compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd as applicable, and opacity) for the pollutants listed below:
   a) Nitrogen Oxides (NO_x)
   b) Carbon Monoxide (CO)
   c) Volatile Organic Compounds (VOC)
   d) Particulate Matter (PM)
   e) Particulate Matter up to 10 microns in diameter (PM_{10})
   f) Sulfur Dioxide (SO_2)
   g) Ammonia (NH_3)
   h) Opacity
   i) Mercury (Hg)
7. The Applicant shall conduct emission tests to demonstrate that the Emergency Syngas Flare is in compliance with the emission limits (lb/MMBtu, lb/hr, and %, as applicable) for the pollutants listed below. Testing for the following pollutants shall be conducted with a steady state heat input of 642 MMBtu/hr (the estimated average heat input over a single shut down event), based on the average of three one-hour runs.:
   a) Nitrogen Oxides (NO_x)
   b) Carbon Monoxide (CO)

c) Volatile Organic Compounds (VOC)
d) Opacity

8. In accordance with 310 CMR 7.04(4)(a), the Applicant shall have Unit 6/Boiler 8 inspected and maintained in accordance with the manufacturer's recommendations and tested for efficient operation at least once in each calendar year. The results of said inspection, maintenance and testing and the date upon which it was performed shall be recorded and posted conspicuously on or near the proposed equipment.
9. In accordance with 310 CMR 7.13 the Department may require additional emissions testing of the facility at any time to ascertain compliance with the Department's Regulations or any proviso(s) contained in this Conditional Approval.
10. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.50Da Compliance Determination Procedures and Methods.

XIII. GENERAL REQUIREMENTS

1. The Applicant shall properly train all personnel to operate the proposed facility and control equipment in accordance with vendor specifications.
2. All requirements of this Conditional Approval that apply to the Applicant shall apply to all subsequent owners and/or operators of the facility.
3. The Applicant shall maintain the standard operating and maintenance procedures for all air pollution control equipment, including the syngas cleanup train, in a convenient location (e.g., control room/technical library) and make them readily available to all employees.
4. The Applicant shall comply with all provisions of 310 CMR 6.00-8.00 that are applicable to this facility.
5. This Conditional Approval may be suspended, modified, or revoked by the Department if, at any time, the Department determines that the facility is violating any condition or part of the Approval.
6. This Conditional Approval does not negate the responsibility of the Applicant to comply with this or any other applicable federal, state, or local regulations now or in the future.
7. The facility shall be operated in a manner to prevent the occurrence of sound, dust or odor conditions that cause or contribute to a condition of air pollution as defined in Regulations 310 CMR 7.01 and 7.09.
8. Should asbestos remediation/removal be required as a result of this Conditional Approval, such asbestos remediation/removal shall be done in accordance with Regulation 310 CMR 7.15 and 310 CMR 4.00.
9. Any proposed increase in emissions above the limits contained in this Conditional Approval must first be approved in writing by the Department pursuant to 310 CMR 7.02. In addition, any emissions increase may subject the facility to additional regulatory requirements.
10. No person shall cause, suffer, allow, or permit the removal, alteration or shall otherwise render inoperative any air pollution control equipment or equipment used to monitor emissions which has been installed as a requirement of 310 CMR 7.00, other than for reasonable maintenance periods or unexpected and unavoidable failure of the equipment, provided that the Department has been notified of such failure, or in accordance with specific written approval of the Department.

11. The proposed facility shall be constructed and operated in strict accordance with this Conditional Approval. Should there be any inconsistencies between the Applicant's NMCPA (4B06046), and this Conditional Approval, this Conditional Approval shall govern.
12. All provisions contained in existing plan approvals concerning the subject facility issued by the Department to Somerset Power LLC, and/or previous owners, remain in effect other than those specifically altered herein.

XIV. CONSTRUCTION REQUIREMENTS

During the construction phase of the proposed modifications at the facility, the Applicant shall ensure that facility personnel take all reasonable precautions (noted below) to minimize air pollution episodes (dust, odor, noise):

1. Facility personnel shall exercise care in operating any noise generating equipment (including mobile power equipment, power tools, etc.) at all times to minimize noise.
2. Construction vehicles transporting loose aggregate to or from the facility shall be covered and shall use leak tight containers.
3. The construction open storage areas, piles of soil, loose aggregate, etc. shall be covered or watered down as necessary to minimize dust emissions.
4. Any spillage of loose aggregate and dirt deposits on any public roadway, leading to or from the proposed facility shall be removed by the next business day or sooner, if necessary.
5. On site unpaved roadways/excavation areas subject to vehicular traffic shall be watered down as necessary or treated with the application of a dust suppressant to minimize the generation of dust.

XV. MASSACHUSETTS ENVIRONMENTAL POLICY ACT

The Department has determined that the filing of an Environmental Notification Form (ENF) with the Secretary of Environmental Affairs, for air quality control purposes, was not required prior to this action by the Department. Notwithstanding this determination, the Massachusetts Environmental Policy Act (MEPA) and Regulation 301 CMR 11.00, Section 11.04, provide certain "Fail-Safe Provisions" which allow the Secretary to require the filing of an ENF and/or an Environmental Impact Report at a later time.

XVI. LIST OF PERTINENT INFORMATION

Application Title:	Technical Support Document, Non-Major Comprehensive Plan Approval Application – Somerset Unit 6 Re-powering dated December 2006
Application Prepared by:	ENSR
Submitted by:	Somerset Power LLC
Attested to by:	Michael Kravett, P.E. No. 46489
Date Application Received:	December 22, 2006
Dates Revisions Received:	March 1, 2007

March 9, 2007
April 20, 2007
June 21, 2007
June 28, 2007
July 10, 2007
August 3, 2007
August 6, 2007
August 7, 2007
August 9, 2007

XVII. APPEAL PROCESS

This approval is an action of the Department. If you are aggrieved by this action, you may request an adjudicatory hearing. A request for a hearing must be made in writing and postmarked within twenty-one (21) days of the date of issuance of this approval.

Under 310 CMR 1.01(6)(b), the request must state clearly and concisely the facts which are the grounds for the request, and the relief sought. Additionally, the request must state why the plan approval is not consistent with the applicable laws and regulations. The hearing request along with a valid check payable to the Commonwealth of Massachusetts in the amount of one hundred dollars ($100.00) must be mailed to:

Commonwealth of Massachusetts
Department of Environmental Protection
P.O. Box 4062
Boston, Massachusetts 02211

The request will be dismissed if the filing fee is not paid unless the appellant is exempt or granted a waiver as described below.

The filing fee is not required if the appellant is a city or town (or municipal agency), county, or district of the Commonwealth of Massachusetts, or a municipal housing authority.

The Department may waive the adjudicatory hearing filing fee for a person who shows that paying the fee will create an undue financial hardship. A person seeking a waiver must file, together with the hearing request as provided above, an affidavit setting forth the facts believed to support the claim of undue financial hardship.

Please be advised that this approval does not negate the responsibility of the Applicant to comply with this or any other applicable federal, state, or local regulations now or in the future. Nor does this approval imply compliance with any other applicable federal, state, or local regulation now or in the future.