COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
**DEPARTMENT OF ENVIRONMENTAL PROTECTION**
SOUTHEAST REGIONAL OFFICE
**20 RIVERSIDE DRIVE, LAKEVILLE, MA 02347 508-946-2700**

MITT ROMNEY
Governor

KERRY HEALEY
Lieutenant Governor

STEPHEN R. PRITCHARD
Secretary

ROBERT W. GOLLEDGE, Jr.
Commissioner

August 22, 2005

Barry A. Ketschke
Dominion Energy Brayton Point, LLC
Brayton Point Station
Brayton Point Road
Somerset, Massachusetts 02726

RE: **REVISED CONDITIONAL APPROVAL**
Application for: BWP AQ 02
Non-Major Comprehensive Plan Approval
310 CMR 7.02 Plan Approval and Emission Limitations
Transmittal No.: W053973
Application No.: 4B04025
Source Number: 0061
Action Code: E-V6

AT: Brayton Point Station
Brayton Point Road
Somerset, Massachusetts 02726

Dear Mr. Ketschke:

The Department of Environmental Protection (the "Department"), Bureau of Waste Prevention has reviewed the Non-Major Comprehensive Plan Application (NMCPA) submitted by USGen New England, Inc., for proposed modifications to the Brayton Point Station (“Facility”) located at Brayton Point Road, Somerset, Massachusetts. Effective January 1, 2005, the ownership of Brayton Point Station was transferred from USGen New England, Inc. to Dominion Energy Brayton Point, LLC.

Proposed modifications to the Brayton Point Station include alterations to existing coal fired electric utility generating Units 1 and 3, and ash processing equipment. The application bears the seal and signature of Val F. Madden, P.E. No. 33713.

The Department on October 20, 2004 issued an Amended Emission Control Plan (ECP) Final Approval that defined how USGen New England, Inc. would come into compliance with 310 CMR 7.29 Emission Standards for Power Plants. The Amended ECP Final Approval and 310 CMR 7.29 required that USGen New England, Inc. submit to the Department an application pursuant to 310 CMR 7.02 Plan Approval and Emission Limitations for the proposed alterations/construction. In response, the applicant submitted the NMCPA that is the subject of this Revised Conditional Approval.

The Department is of the opinion that the material submitted is in conformance with the current Massachusetts Air Pollution Control Regulations and hereby issues the **REVISED CONDITIONAL APPROVAL** for the proposed alterations of the facility, subject to the conditions and provisions stated herein. The Revised Conditional Approval supersedes the June 27, 2003 Conditional Approval.

The NMCPA was submitted in accordance with Section 7.02 Plan Approval and Emission Limitations as contained in 310 CMR 7.00 "Air Pollution Control Regulations", adopted by the Department pursuant to the authority granted by Massachusetts General Laws, Chapter 111, Section 142 A-M. 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 Revised Conditional Approval combines and includes: the 310 CMR 7.02 Comprehensive Plan Approval; and the 310 CMR 7.00: Appendix A: Emission Offsets and Nonattainment Review analysis; and hereby incorporates the NMCPA submitted by USGen New England, Inc. and revisions submitted by Dominion Energy Brayton Point, LLC by reference, including the October 20, 2004 Amended ECP Final Approval.

A stamped approved copy of the NMCPA is enclosed. A list of submitted information pertinent to the application is delineated on page 26.

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

Very truly yours,

**This final document copy is being provided to you electronically by the Department of Environmental Protection. A signed copy of this document is on file at the DEP office listed on the letterhead.**

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

Enclosure

cc: Brendan McCahill
U.S. EPA Region I – Air Permits
One Congress St., (CAP)
Boston, MA 02114

ecc: Board of Health, Somerset, MA
Fire Department, Somerset, MA
Lou Arak, Dominion Resources Services, Inc.
Kenneth Small, Dominion Energy Brayton Point, LLC
David Shotts, P.E., TRC Environmental Corp., Lyndhurst, NJ
Seth Kaplan, CLF, Boston, MA
Christopher D'Ovidio, CLF, Providence, RI
Cindy Luppi, Clean Water Action, Boston, MA
Nancy Seidman, DEP/BWP–Boston
Robert Donaldson, DEP/BWP-Boston
Don Squires, DEP/BWP–Boston
Yi Tian, DEP/BWP-Boston
Susan Ruch, DEP/OGC–Boston
Sharon Weber, DEP/BWP–Lawrence
Ed Braczyk, DEP/BWP-NERO
David Johnston, DEP/BWP-SERO
Mark Poudrier, DEP/BWP-SERO

# TABLE OF CONTENTS

## List of Abbreviations

ARP…………………ash reduction process
BACT…………………Best Available Control Technology
Btu/kWh…………….British Thermal Units per kilowatt hour
Btu/lb………………..British Thermal Units per pound
CEM………..………continuous emission monitor
COM……………….. continuous opacity monitor
CO………………….. carbon monoxide
$CO_2$…………………carbon dioxide
ECP………………… Emission Control Plan
EPA………………… U.S. Environmental Protection Agency
ESP…………………electrostatic precipitator
FGD…………………flue gas desulfurization
Hg……………………. mercury
HAP……………….... Hazardous Air Pollutant
HHV………………...higher heating value
lb/hr………………… pound per hour
lb/MMBtu…..………. pound per million British Thermal Units
lb/MWh…….………pound per megawatt hour
LAER……………… lowest achievable emission rate
LOI…………………loss-on-ignition
MCPA………………Major Comprehensive Plan Application
MCR……………….. maximum continuous rating
MMBtu/hr…………..Million British Thermal Units per hour
MW………………… megawatt
NAAQS……………..National Ambient Air Quality Standards
$NH_3$…………………ammonia
NMCPA……………..Non-Major Comprehensive Plan Application
$NO_2$…………………nitrogen dioxide
$NO_x$…………….……nitrogen oxides
$O_3$…………………... ozone
$ppm_{vd}$ @ 3% $O_2$……. parts per million volume dry corrected to three percent oxygen
Pb…………………... lead
PM…………………..particulate matter
$PM_{10}$………………... particulate matter up to 10 microns in size
$PM_{2.5}$………………...particulate matter up to 2.5 microns in size
POTW………………publicly owned treatment works
PTE…………………potential to emit
SCR…………………selective catalytic reduction
$SO_2$………… ………sulfur dioxide
$SO_3$………… ………sulfur trioxide
tpy…………………...tons per consecutive twelve-month period
VOC…………………volatile organic compound
WWTP………………wastewater treatment plant

# I. FACILITY DESCRIPTION

## A. Site Description

The Dominion Energy Brayton Point, LLC (the "Applicant"), formally USGen New England, Inc., Brayton Point Station site consists of approximately 250 acres of land situated in a mixed use area of Somerset, Massachusetts consisting of residential and commercial properties. The existing Brayton Point Station includes approximately 1,589 MW net of coal, residual oil and natural gas boiler based electric power generation equipment, and approximately 11 MW of No. 2 distillate oil diesel engine based electric power generation equipment. The site is bordered by the Lee River to the west; the Taunton River to the east; residential properties and U.S. 195 to the north; and Mount Hope Bay to the south.

## B. Project Description

Dominion Energy Brayton Point, LLC Brayton Point Station is subject to 310 CMR 7.29 Emission Standards for Power Plants that were promulgated on May 11, 2001. These regulations impose new facility-wide annual and calendar month emission limits for $NO_x$, $SO_2$, and $CO_2$, in units of lb/MWh net, and will result in future Hg control requirements. These regulations did not impose CO and $PM_{2.5}$ emission standards at this time but indicated that development of 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. The Department of Environmental Protection (the "Department") issued Final Approval of the ECP to USGen New England, Inc. on June 7, 2002. The Final Approval advised USGen New England, Inc. of the requirement to receive a Plan Approval pursuant to 310 CMR 7.02 for the proposed alterations/construction. On April 26, 2002, the Department received the Applicant's Major Comprehensive Plan Application (MCPA) requesting Plan Approval of the proposed alterations/construction. The Department issued Conditional Approval of MCPA to USGen New England, Inc. on June 27, 2003.

310 CMR 7.29 Emission Standards for Power Plants were amended on June 4, 2004. The amendments imposed new facility-wide calendar year Hg emission cap and imposed Hg removal efficiencies or Hg emission limits in units of lb/MWh net. These regulation amendments required applicable power plants to submit an amendment to the approved ECP to incorporate the Hg emission cap. On July 30, 2004, the Department received the applicant's amended ECP application that requested approval of the Hg emission cap, the use of aqueous ammonia for use in the SCR $NO_x$ control systems, and clarification of the construction schedule. The Department issued an Amended Emission Control Plan Final Approval to USGen New England, Inc. on October 20, 2004. On August 11, 2004, the Department received the applicant's Non-Major Comprehensive Plan Application (NMCPA) for the proposed alterations/construction.

Air contaminant emission increases due to the alterations/construction are addressed in the Best Available Control Technology (BACT) analysis section of this Revised Conditional Approval. The minor emission increases associated with the material handling and storage systems described herein are exempt from 310 CMR 7.02 Plan Approval and Emission Limitations, pursuant to 310 CMR 7.03(12) and (22); minor emission increases associated with the transfer of ship-delivered limestone to a receiving hopper with wind barrier as dust control and the use of gray water from the Town of Somerset POTW in the FGD system, bottom ash system makeup and boiler seal are exempt from 310 CMR 7.02 Plan Approval and Emission Limitations, pursuant to 310 CMR 7.02(2)(b)7. *De minimus* Increase in Emissions.

The Applicant proposes alterations of Unit 1, Unit 3 and the Fly Ash Separation System. These alterations will change air contaminant emissions to the ambient air and the estimated actual emission changes are defined in Table 1.

**Table 1: ACTUAL EMISSION CHANGE ESTIMATE**

| | | **Past Actual Baseline[1]** | | **Future Actual Estimate** | | **Net Change** |
|---|---|---|---|---|---|---|
| | | **Unit 1** | **Unit 3** | **Unit 1** | **Unit 3** | |
| Fuel | MMBtu/yr | 15,956,468 | 35,640,854 | 15,956,468 | 35,640,854 | 0 |
| Fuel | % of max. [2] | 81 | 72 | 81 | 72 | 0 |
| $NO_x$ | tons/yr | 2362 | 7,306 | 638 | 1,426 | **-7,604** |
| CO | tons/yr | 167 | 1388 | 167 | 1,384 | **-4** |
| VOC | tons/yr | 20.0 | 43.5 | 20.0 | 44.0 | **+0.5[3]** |
| $SO_2$ | tons/yr | 8,718 | 20,405 | 8,630 | 1,960 | **-18,533** |
| PM | tons/yr | 120 | 125 | 167 | 535 | **+457[4]** |
| $NH_3$ | tons/yr | 0 | 0 | 8 | 18 | **+26[5]** |
| Opacity[6] | % | 0-5 | 0-5 | 0-5 | 0-5 | **0** |

Note:
1 – Average for years 2000 and 2001.
2 – Equivalent heat input capacity factor.
3 – Increase due to VOC from FGD make-up water.
4 – Increase based on 100% of $NH_3$ conversion to ammonia bisulfate and FGD limestone slurry based particulate and no air pollution controls.
5 – Estimate is conservative since based on SCR $NH_3$ slip with no conversion to ammonia bisulfate (refer to Note-4) and no reduction due to FGD.
6 – Exclusive of uncombined water

## C. Description of Proposed Alterations

The Applicant proposes alterations to Unit 1, Unit 3 and the Fly Ash Separation System, as follows:

<u>Unit 1</u>
Unit 1 is rated at 255 MW net with steam provided by a Combustion Engineering boiler that utilizes pulverized coal at 100% MCR as the primary fuel, natural gas at 25% MCR as a secondary fuel, No. 6 Fuel Oil at 100% MCR as a back-up fuel, and No. 2 Fuel Oil at 100% MCR as an alternate back-up fuel. The boiler is rated at 2,250 MMBtu/hr heat input. Products of

combustion are released to the ambient air from a stack 352.8 feet above ground level (367.3 feet above sea level) with an inside exit diameter of 174 inches.

Unit 1 will be equipped with a selective catalytic reduction (SCR) system for the control of $NO_x$ emissions. The SCR system is designed for up to 90% control of $NO_x$. The facility will utilize aqueous ammonia solution (ammonia concentration less than 20% by weight) to generate ammonia for injection at the SCR inlet.

Unit 1 is currently equipped with ABB-Combustion Engineering low-NOx burners and two ESPs in series with the Koppers ESP upstream of the Research-Cottrell ESP. An EPRICON flue gas conditioning system can provide $SO_3$ upstream of the Koppers ESP to increase the resistivity of the particulate to improve particulate collection by the ESPs. The EPRICON flue gas conditioning system will be removed since $SO_2$ passing through the proposed SCR $NO_x$ controls will partially convert $SO_2$ to $SO_3$ and provide $SO_3$ for particle conditioning upstream of the ESPs. The Chemithon flue gas condition system described below and currently used with Unit 3 may be used to supply $SO_3$ to Unit 1 during the construction of the equipment approved herein. Babcock Power Environmental, Inc. has been selected as the vendor for the SCR emission control system for Unit 1.

<u>Unit 3</u>
Unit 3 is rated at 633 MW net with steam provided by a Babcock and Wilcox boiler that utilizes pulverized coal at 100% MCR as the primary fuel, natural gas at 10% MCR as a secondary fuel, No. 6 Fuel Oil at 100% MCR as a back-up fuel, and No. 2 Fuel Oil at 100% MCR as an alternate back-up fuel. The boiler is rated at 5,655 MMBtu/hr heat input. Products of combustion are released to the ambient air from a new stack 504.5 feet above ground level (544.5 feet above sea level) with an inside exit diameter of 258 inches when the wet FGD system is in operation. When the FGD system is not in operation the products of combustion will be released from the existing stack 352.8 feet above ground level (367.3 feet above sea level) with an inside exit diameter of 234 inches.

Unit 3 will be equipped with an SCR system for the control of $NO_x$ emissions and Wet Flue Gas Desulfurization (FGD) system, using limestone as the reagent, for the control of $SO_2$, including residual $SO_3$. The SCR system is designed for up to 90% control of $NO_x$ and the FGD system is designed for up to 95% control of $SO_2$. A proposed new stack 504.5 feet above ground level with an inside diameter of 258 inches will serve the FGD system. The existing stack will continue to serve Unit 3 when the FGD system is shutdown. The facility will utilize aqueous ammonia solution (ammonia concentration less than 20% by weight) to generate ammonia for injection at the SCR inlet.

Unit 3 is currently equipped with Babcock & Wilcox low-NOx burners and two ESPs in series with the Koppers ESP upstream of the Research-Cottrell ESP. A Chemithon flue gas conditioning system can provide $SO_3$ upstream of the Research-Cottrell ESP to increase the resistivity of the particulate to improve particulate collection by the ESPs. The Chemithon flue gas conditioning system will be removed since $SO_2$ passing through the proposed SCR $NO_x$

controls will partially convert $SO_2$ to $SO_3$ and provide $SO_3$ for particle conditioning upstream of the ESPs.

Babcock Power Environmental, Inc., has been selected as the vendor for the SCR and FGD emission control systems for Unit 3.

Fly Ash Separation System

The existing fly ash separation system, which includes Separation Technologies, Inc. (STI) equipment, processes coal fly ash from Unit 1, 2 & 3 due to the fly ash carbon content. Fly ash from Unit 1,2 & 3 ESP hoppers is pneumatically conveyed to the fly ash storage silos and the transport air is returned to the ESP inlets. The STI equipment electrostatically separates ash into low-carbon ash and high-carbon ash and conveys the ash to separate silos. Low-carbon ash is sold as a product for concrete manufacturing, and the high-carbon ash is land filled or sent to cement kilns.

An Ash Reduction Process (ARP) is proposed to replace the STI equipment to improve the beneficial use of the coal fly ash. The ARP will produce a high quality ash with a lower carbon content to be used as a replacement of Portland cement in the production of concrete.

Approximately 85% of the total ash produced by Units 1, 2 & 3 is fly ash, with the remainder being bottom ash.

Ash Reduction Process

The proposed ARP will process coal fly ash as described in the NMCPA. $NO_x$ emission controls tend to increase Unit 1, 2 & 3 BTU/kWh heat rates due in part to unburned carbon remaining in the fly ash. The percentage of carbon in the ash is expressed as loss-on-ignition (LOI) and a high LOI represents a loss of combustion efficiency and an overall increase in heat rate, resulting in lower overall power generation efficiency.

Units 1, 2 & 3 produce relatively high-carbon fly ash, typically as high as 10.6%, which reduces its marketability as a product. Low-carbon ash, typically 2.5% or less, is used in the manufacturing of concrete. As proposed the ARP will be either a fluidized bed furnace or a multiple hearth furnace to recover a substantial amount of the heat that would normally be wasted through the disposal of high-carbon fly ash. The chosen furnace will have a maximum design heat input of 97 MMBtu/hr with the exhaust routed through a new baghouse fabric filter particulate control device and then conveyed to the windbox of Unit 3. When Unit 3 is not available the exhaust will be directed to the windbox of Unit 1, and when both Unit 1 and Unit 3 are not operating the ARP will be shutdown.

Material Handling And Storage

Additional material handling and storage activities will be needed to support the FGD and SCR emission control systems. Storage domes, fully enclosed conveyors and transfer points and fabric filter particulate collectors will be used to minimize particulate emissions to the ambient air. The transfer of ship-delivered limestone to a receiving hopper with wind barrier as dust control, and the gray water on-site use are exempt from 310 CMR 7.02 Plan Approval and Emission

Limitations pursuant to 310 CMR 7.02(2)(b)7. *De minimus* Increase in Emissions. All other material handling and storage activities are exempt from 310 CMR 7.02 Plan Approval and Emission Limitations pursuant to 310 CMR 7.03(12) and (22). Material handling and storage include the following:

<u>Limestone</u>
Limestone will be delivered to the facility by ships or covered trucks. Limestone will be unloaded by the ship's unloading boom conveyor and transferred to a new receiving hopper with a wind barrier at the top of the hopper to minimize particulate emissions. The transfer of ship-delivered limestone to a receiving hopper with wind barrier as dust control is exempt from 310 CMR 7.02 Plan Approval and Emission Limitations pursuant to 310 CMR 7.02(2)(b)7. *De minimus* Increase in Emissions. From the receiving hopper, limestone is conveyed through two transfer towers to a conveyor that transports the limestone to the storage dome. Trucks will dump limestone inside the dome. The storage dome will be ventilated thorough a fabric filter particulate collector(s) to minimize particulate emissions.

Limestone will be loaded by front-end loaders onto a conveyor within the storage dome and delivered to the lime stone storage silo that will be equipped with a fabric filter particulate collector. From the storage silo, the limestone will be fed to the wet FGD equipment.

<u>Gypsum</u>
Gypsum, the product of the FGD system, will be handled in the same storage dome as the limestone. Dewatered gypsum will be removed from the site by ship or truck. From within the storage dome, gypsum will either be loaded onto a conveyor or a front-end loader will load gypsum into trucks. For ship loading, a series of conveyors, transfer towers and a telescoping chute that discharges into the ship will be used.

<u>Ammonia</u>
Ammonia in an aqueous solution less than 20% by weight ammonia will be utilized as the reagent for the SCR systems for Units 1 and 3. The aqueous ammonia will be delivered to the site by truck and stored in four 55,000-gallon tanks. Each tank will have its own contaminant equipped with control measures designed to minimize ammonia evaporation and air emissions in the event of a spill.

<u>Fly Ash and ARP Product</u>
Fly ash from will be pneumatically transferred to the ARP fly ash feed silo. From the ARP, the fly ash will be stored in the ARP fly ash storage dome and transferred pneumatically to the fly ash load-out silo for load-out into tank trucks, or will be directly transferred from the storage dome pneumatically to the barge. Ash transferred from the silos to trucks or from the dome to the barge will be equipped with telescoping air slide load-out chutes and particulates will be controlled by fabric filters at a particulate control efficiency of at least 99.5%. Each silo and the ARP fly ash storage dome will be equipped with a fabric filter particulate collector.

Gray Water On-site Use

Gray water from the Somerset POTW will be used in the FGD system; other potential uses include bottom ash system makeup and boiler seal. Gray water will not be used for FGD final stage mist eliminator spray wash.

## II. EMISSIONS

### A. Background

Emissions to the ambient air from Units 1 and 3 operation currently include the following criteria air contaminants: PM, $PM_{10}$, $SO_2$, CO, $NO_x$, Pb and VOC. With the addition of the proposed modifications, none of the criteria air contaminants will realize a potential to emit increase greater than 1 ton per year. A non-criteria air contaminant, $NH_3$, PTE is proposed to increase by 35 tons per year and post construction $NH_3$ emission testing will define $NH_3$ control efficiencies and emission rates for the various air pollution control systems and it is anticipated that the data will reveal that the PTE for $NH_3$ will be significantly less than 35 tons per year.

### B. New Emission Limits

1. Unit 1 shall not exceed the ammonia emission limits as specified in Table 2:

| Table 2: UNIT 1 AMMONIA EMISSION LIMITS | | | | |
|---|---|---|---|---|
| **Emission** | **$ppm_{vd}$ @ 3% $O_2$[1]** | **lb/MMBtu[1]** | **lbs/hr[1]** | **tpy[2]** |
| $NH_3$ | 2 | 0.001 | 2.26 | 9.9 |

Note:
1 - One-hour average, measured at the stack.
2 - Tons per consecutive 12-month period.

2. Unit 3 shall not exceed the ammonia emission limits as specified in Table 3:

| Table 3: UNIT 3 AMMONIA EMISSION LIMITS | | | | |
|---|---|---|---|---|
| **Emission** | **$ppm_{vd}$ @ 3% $O_2$[1]** | **lb/MMBtu[1]** | **lbs/hr[1]** | **tpy[2]** |
| $NH_3$ | 2 | 0.001 | 5.71 | 25.0 |

Note:
1 - One-hour average, measured at the stacks (existing Stack No. 3 and new Stack No. 5).
2 - Tons per consecutive 12-month period.

3. Unit 1 will become subject to Table 2 emission limits as of the date specified in Section XI.4.c, but not later than 180 days after initial injection of $NH_3$ up-stream of the SCR catalyst.

4. Unit 3 will become subject to Table 3 emission limits as of the date specified in Section XI.4.d, but not later than 180 days after initial injection of $NH_3$ up-stream of the SCR catalyst, and no later than 10/01/06

5. The Department reserves the right to establish new final particulate emission limits at the stacks serving Units 1 and Unit 3 (both stacks) based upon post construction emission testing and operating data.

## III. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

### A. Background

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

The state government under the jurisdiction of the Department of Environmental Protection (the “Department”) has adopted these ambient air quality standards for the Commonwealth of Massachusetts as stated under 310 CMR 6.00 Ambient Air Quality Standards for the Commonwealth of Massachusetts. 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 country as “attainment”, “nonattainment”, or “unclassified” with respect to the NAAQS.

New major sources of regulated air pollutants or major modifications to existing major 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 tons per year (tpy) or more of any pollutant and is listed as one of the 28 designated PSD stationary source categories, and is considered a “major modification” if the physical change or change in the method of operation of a “major” source would result in a significant net emission increase.

Effective July 1, 1982, the PSD program has been implemented by the Department in accordance with the Department's "Procedures for Implementing Federal Prevention of Significant Deterioration Regulations". On April 26, 2002, USGen New England, Inc. submitted to the Department an application, pursuant to 310 CMR 7.02 to alter and operate existing Brayton Point Station Units 1 and 3, steam to electric power generation units. Unit 1 design basis is 2,250 MMBtu/hr heat input and Unit 3 design basis is 5,655 MMBtu/hr, per the Title V Permit. Thus, the Brayton Point 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. The Brayton Point Station is an existing major source of regulated air pollutants.

Effective March 3, 2003, the Department notified U.S. 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 Units 1 and 3 at the electric utility steam generating facility in Somerset, Massachusetts. The facility is located in an area which is in either "attainment" or "unclassified" for Sulfur Oxides measured as $SO_2$, $NO_2$, CO, Pb, and PM, which includes $PM_{10}$. 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 "serious" nonattainment for the pollutant $O_3$ NAAQS. $NO_x$ and VOC emissions are precursors to the formation of $O_3$.

New major sources of regulated air pollutants or major modifications to an existing major 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 tons per year (tpy) or more of $NO_x$ or VOC, and is considered a "major modification" if the physical change or change in the method of operation of a "major" 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. A physical change or change in the method of operation does not include the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the Department determines that such addition, replacement, or use renders the unit less environmentally beneficial.

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 Unit 1 and Unit 3 are not categorized as a "major modification" to an existing major source since the alteration has been determined by the Department to be a "pollution control project" at an existing steam generating unit that is "environmentally beneficial".

Table 4 identifies $NO_x$ and VOC emission factors for past actual baseline 2000-2001 average emissions and predicted post retrofit with SCR, FGD and ARP average emissions.

| **Table 4: EMISSION FACTORS – lb/MMBtu** | | | | |
|---|---|---|---|---|
| | **Past Actual Baseline 2000-2001 Average** | | **Predicted Post Retrofit W/SCR, FGD & ARP** | |
| **Emission** | **Unit 1** | **Unit 3** | **Unit 1** | **Unit 3** |
| $NO_x$ | 0.30 | 0.41 | 0.08 | 0.08 |
| VOC | 0.0025 | 0.0024 | 0.0025 | 0.0025 |

Table 5 identifies the net emission changes for Unit 1 and Unit 3 for emissions subject to Nonattainment review.

| **Table 5: NONATTAINMENT REVIEW** | | | | | | |
|---|---|---|---|---|---|---|
| | | **Past Actual Baseline 2000-2001 Average** | | **Future Representative Actual Annual Emissions[2]** | | **Net Change** |
| | | **Unit 1** | **Unit 3** | **Unit 1** | **Unit 3** | |
| Fuel | MMBtu/yr | 15,956,468 | 35,640,854 | 15,956,468 | 35,640,854 | 0 |
| Fuel | % of max.[1] | 81 | 72 | 81 | 72 | 0 |
| $NO_x$ | tons/yr | 2362 | 7,306 | 638 | 1,426 | **-7,604** |
| VOC | tons/yr | 20.0 | 43.5 | 20.0 | 44.0 | **+0.5** |

Note:
1 – Equivalent heat input capacity factor.
2 – Future Representative Actual Annual Emissions based on the same heat input rate as Past Actual Baseline.

The project, based on past actual emissions to future representative actual annual emissions, will result in significant $NO_x$ emission reductions, and less than significant net increase in representative actual emissions of VOC. The minor facility wide collateral VOC actual emission increase will not adversely affect NAAQS for ozone due to the substantial reductions of $NO_x$ emissions.

## C. Conclusion

Unit 1 and Unit 3 modifications, based on current information and pursuant to 310 CMR 7.00 Appendix A(2), is not considered a “major modification” to an existing major source. The proposed alteration/construction has been determined by the Department, pursuant to 310 CMR 7.00 Appendix A(2)(“major modification”)(c)(8), to be a “pollution control project” at existing electric utility steam generating units that is “environmentally beneficial”. 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 (NSPS)

Unit 1 and Unit 3 are considered to be a “fossil-fuel fired steam generating unit” and an “electric utility steam generating unit” since each Unit burns fossil fuels at a rate greater than 250 MMBtu/hr and more than one third of each Unit’s net electrical output will be sold to a utility.

Construction/alteration of Unit 1 and Unit 3 will not constitute a “modification” since the primary function is the reduction of air pollutants. Substantial emission reductions of $NO_x$ will be realized with the SCR system on Unit 1; substantial emission reductions of $NO_x$ and $SO_2$ will be realized with the SCR & FGD systems on Unit 3; and potential particulate emissions will not increase. In addition, the construction/alterations are not by definition “reconstruction” since the additional air pollution controls do not constitute “replacement of components”.

The New Source Performance Standards (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, are not applicable to either Unit 1 or Unit 3.

Based on a recent determination issued by USEPA Region 4, NSPS Subpart Dc applies to the ash reduction process (ARP) that is proposed as an integrated element of the ECP, because the ARP heat recovery meets the definition of a “steam generating unit.” Because the fly ash is not considered to meet the definition of coal, no Subpart Dc emission standards apply. However, the facility must meet the record keeping and reporting requirements of Section 60.48c(g) and the general provisions in 40 CFR 60.7.

## VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

### A. Background

Pursuant to 310 CMR 7.00 Definitions and 310 CMR 7.02(3)(j)6., the Applicant is required to evaluate Best Available Control Technology (BACT) for the “alterations” and “construction” as it applies to any air contaminant that will result in a potential emission increase. BACT is defined as an emission limitation using the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, energy and environmental factors.

Unit 1 and Unit 3 will have potential emission increases greater than 1 ton per year for $NH_3$ associated with the SCR $NO_x$ emission control systems. Excess $NH_3$ that does not react in the SCR system catalyst bed, referred to as $NH_3$ slip, will be emitted from stacks of Units 1 and 3. Therefore, BACT review requirements are limited to $NH_3$ emissions.

In addition, the wastewater treatment plant (WWTP) will have a potential emission increase of $NH_3$ due to treatment of wastewater streams containing $NH_3$ from Units 1 and 3 air pre-heater and electrostatic precipitator washes and the Unit 3 FGD blow-down. Therefore, the WWTP BACT review requirements are limited to $NH_3$ emissions.

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 facility must utilize BACT to control $NH_3$ emissions. The Department has verified and concurs with the following BACT Analysis (as referenced in the Applicant's MCPA).

## B. Ammonia ($NH_3$) BACT Analysis

**Table 6: $NH_3$ Comparative BACT Analysis Unit 1 and Unit 3**

| Control Technology | Emission Rate[1] | BACT | Costs[2] | Reason |
|---|---|---|---|---|
| $SCONO_x$ | 0 ppmvd @ 3% $O_2$ | No | N/A | The technology has not been demonstrated on boilers burning residual oil or coal. Technology has been demonstrated on gas fired combustion turbines. |
| SCR | 2 ppmvd @ 3% $O_2$ | Yes | $$ | Method chosen to achieve BACT and lower than the lowest emission rate demonstrated from a coal fired boiler with SCR. The lowest emission rate identified for a coal fired boiler with SCR is 5 ppmvd @ 3% $O_2$, or 2.5 times higher than that proposed. $NH_3$ preferentially reacts with $SO_3$ to form particulate ammonia salts downstream of the SCR systems with little anticipated impact to the wastewater and represents BACT for the WWTP as well. |

Note:
1 - Potential Emissions
2 - $ = least expensive (relative to control technologies for that specific pollutant)
$$ = moderately expensive (relative to control technologies for that specific pollutant)
$$$ = fairly expensive (relative to control technologies for that specific pollutant)
$$$$ = very expensive (relative to control technologies for that specific pollutant)
$$$$$ = extremely expensive (relative to control technologies for that specific pollutant)

<u>Conclusion:</u>
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 limiting the $NH_3$ emissions to no greater than 2 ppmvd @ 3% $O_2$ is the best achievable control technology, or BACT, for $NH_3$.

# 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.

Based upon a review of Department records, the existing facility has not caused a condition of air pollution due to sound emissions since the coal conversion in the 1980's.

## B. General Information

Sound mitigation measures

1. Thermal lagging on the following fans/blowers:
   - Unit 3 vent filter fan
   - Fluidized Bed or Multiple Hearth Combustion Force Draft Fan
   - Dust Collection System Surge Bin Aeration Blower
   - Dust Collection System Induced Draft Fan
   - Selective Catalytic Reduction Ammonia Injection Dilution Air Blowers
   - Product Ash Transport Air Supply Fans
   - Selective Catalytic Reduction Replacement Fans

2. Acoustical lagging on the following fans:
   - Unit 3 Induced Draft Fans
   - Unit 3 Flue Gas Booster Fans

3. A three sided barrier (firewalls) around the auxiliary transformers (two feet higher than transformers).

Sound Monitoring/Modeling

1. Sound monitoring at five nearby receptor locations was performed during March and May, 2002.

2. Predicted impacts reveal that four of the five receptor locations will result in an increase of 1 dB(A) or less for a total impact between 39-47 dB(A). The fifth receptor will result in an increase of 3 dB(A) for a total impact of 40 dB(A).

3. At the fifth receptor that will realize a 3 dB(A) increase, the overall sound impact will be 2-7 dB(A) less than three of the four other receptors and 1 dB(A) greater in comparison to the forth receptor.

**C. Conclusion**

Sound impacts proposed in the pending application meet the requirements contained in 310 CMR 7.10 Noise and will not cause or contribute to a condition of air pollution.

A post construction sound survey shall be conducted to define actual sound impacts in comparison to impacts proposed in the application approved herein. Post construction sound surveys shall be conducted no later than 180 days after the later of the dates specified in Section XI.4.c and d. and again within 180 days after the date specified in Section XI.4.e. with the final reports submitted to the Department within 60 days after each survey.

## VIII. SPECIAL CONDITIONS

### A. General Special Conditions

1. The Applicant shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(5)(c), the general plans and specifications, as applicable and available, for the construction/alterations of each system approved herein 30 days prior to commencement of construction/installation of each system.

2. Pursuant to Regulation 310 CMR 7.00: Appendix C and the November 7, 1995 US EPA letter to STAPPA/ALAPCO, the modification approved herein will be a "Minor Modification" to Operating Permit 4V95056 since this Revised Conditional Approval No. 4B02012 is a minor New Source Review action. As such, the Applicant shall comply with Appendix C(4)(b)2. and Appendix C(8)(d) Processing a Minor Modification.

3. The Applicant shall submit Standard Operating and Maintenance Procedures (SOMP) for the new and altered 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 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.

**B. Special Conditions Specific to the Installation of the SCR Emission Control Systems**

1. The Applicant shall submit to the Department final project design information by October 1, 2006 including, but not limited to, all documents not submitted with application approved herein (refer to Appendix A, Form BWP AQ CPA-1, Section B) and revised forms contained in Appendix A of the application, with the exception of Forms BWP AQ SFC-7.

2. The Applicant, within 15 months after October 1, 2006, shall propose to the Department new particulate emission limits for the existing stacks of Unit 1 and Unit 3 and provide supporting justification for the proposed emission limits. A minimum of four (4) particulate emission tests shall be conducted on each of the two (2) existing stacks serving Units 1 and 3. The Department will establish a final particulate emission limit after review of the applicants proposed final emission limits and supporting documentation.

3. 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, $NH_3$ CEMs and operating experience.

4. The basis for $NH_3$ emission compliance determination will automatically convert from quarterly compliance testing to the $NH_3$ CEM system upon each Unit's CEM system demonstration that the relative accuracy of the $NH_3$ CEM system is within +/- 15% for four consecutive quarters and the $NH_3$ CEM system was operating 90% of the time during the same period.

5. Unit 1 and Unit 3 shall meet the $NH_3$ emission limits approved herein within four hours from initiating $NH_3$ feed to the SCR based upon compliance level ammonia CEM system data. During shutdown of the $NH_3$ system, Unit 1 and Unit 3 will be exempt from the hourly limits during the last hour of the $NH_3$ feed to the SCR.

**C. Special Conditions Specific to the Installation of the FGD Emission Control System**

1. The Applicant shall submit to the Department final project design information prior to installation of the equipment including, but not limited to, all documents not submitted with application approved herein (refer to Appendix A, Form BWP AQ CPA-1, Section B) and revised forms contained in Appendix A of the application, with the exception of Forms BWP AQ SFC-7.

2. The Applicant, within 15-months after the date specified in Section XI.4.e, shall propose to the Department new Unit 3 particulate emission limits and provide supporting justification for the proposed emission limits. A minimum of four (4) particulate emission tests shall be conducted on the new Unit 3 FGD stack. The Department will

establish a final particulate emission limit after review of the applicants proposed final emission limits and supporting documentation. Prior to establishment of this new limit the new Unit 3 FGD stack will be subject to the existing particulate limit of 0.08 lb/MMBtu.

**D. Special Condition Specific to the installation of the ARP**

1. The Applicant shall submit to the Department final project design information by October 1, 2006 including, but not limited to, all documents not submitted with application approved herein (refer to Appendix A, Form BWP AQ CPA-1, Section B) and a completed Form BWP AQ CPA-1 Comprehensive Plan Approval Application for Fuel Utilization Facilities and BWP AQ SFC-1 Dry Air Filters (Fabric, Bags, Cartridges, etc.) for the ARP and fabric filter for particulate control.

2. The ARP shall not operate when Unit 1 and Unit 3 are both shutdown.

3. During start-up and commissioning, the ARP emissions may be routed to Unit 1.

## IX. MONITORING AND RECORDING REQUIREMENTS

1. All current monitoring and recording requirements remain in effect and are not altered herein.

2. Unit 1 and Unit 3 (Stack 5 from FGD) shall be equipped with $NH_3$ CEMs with the outputs directed to the data acquisition system. These monitors will be used initially as operating indicators versus direct compliance level monitors due to the uncertain $NH_3$ CEM performance on coal fired boilers. The $NH_3$ CEMs will become direct compliance monitors upon written notification by the Department to Dominion Energy Brayton Point, LLC based on a determination by the Department that the $NH_3$ CEMs are reliable and accurate. The $NH_3$ CEMs shall comply with the linearity check and RATA frequencies and grace periods as specified in 40 CFR 75 in conducting gas audits and RATAs.

3. The new Unit 3 stack (Stack 5 from the FGD) shall be equipped with flow monitoring, $NO_x$, $SO_2$, CO and $CO_2$ or $O_2$ CEMs and a continuous opacity monitor (COM). The CEMs and COM shall meet 40 CFR 75 requirements, with the exception of the CO CEM that shall meet the 40 CFR 60 Appendix B performance specifications and Appendix F for quality assurance and quality control.

4. The Unit 3 existing stack (Stack 3) CEM for CO shall comply with the linearity check and RATA frequencies and grace periods as specified in 40 CFR 75 in conducting cylinder gas audits and RATAs.

5. At least 60 days prior to commencing construction of the CEM/COM systems, protocols and plans for the new CEM/COM systems, including $NH_3$ CEMs, and supporting documentation, shall be submitted to the Department for review and approval.

6. $NH_3$ CEM data will initially be used as an operational tool. Compliance with the $NH_3$ emission limit will be determined during the initial compliance test, and by quarterly compliance testing performed three, six, nine and every twelve months thereafter. The $NH_3$ CEMs shall operate during $NH_3$ compliance testing and the test report shall be submitted to the Department within 30 days after completion of testing. On an annual basis, starting 90 days after the fourth compliance test (initial and following three quarters), the applicant shall submit a report on the performance and relative accuracy of the $NH_3$ CEMs along with a recommendation on the feasibility of their use as a compliance determination method for each unit.

7. Monitor the fly ash fuel feed rates to the ARP and record daily feed rates in tons per day.

8. Fly ash feed to and flyash product from the ARP shall be sampled on a calendar quarter basis and analyzed for higher heat value (HHV) in units of Btu/lb.

## 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. The record keeping log/system, including any other “credible evidence”, 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 emission limits contained in this Revised Conditional Approval. Such records shall include, but are not limited to, fuel usage rate, 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 1 and Unit 3 emission 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 daily fly ash feed to the ARP in tons per day.

5. The applicant shall maintain calendar quarter records of the fly ash heat input to and fly ash product from the ARP in units of Btu/lb.

6. The use of wastewater from the Somerset POTW that contain VOCs and the transfer of ship-delivered limestone to the receiving hopper controlled by a wind barrier as dust control are subject to the record keeping requirements contained in 310 CMR 7.02(2)(e).

## XI. REPORTING REQUIREMENTS

1. All notifications and reporting required by this Revised 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, the Applicant on an annual basis for a period of 5 years from the date each unit (Unit 1 and Unit 3) resumes regular operation after completion of the steps identified in 4.c, 4.d and 4.e of this Section, shall submit information demonstrating that the physical or operational change 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 the Applicant that the increase is unrelated to the alterations/construction approved herein, such as, any increased utilization due to the rate of electricity demand growth for the utility system as a whole. If the installations of the Unit 3 SCR and FGD emission control systems do not coincide, Unit 3 will have two different 5-year periods subject to the requirements of this condition.

3. The Applicant shall notify the Department by telephone or fax no later than three (3) business days after the occurrence of any upsets or malfunctions to the proposed facility

equipment, air pollution control equipment, or monitoring equipment which results in an excess emission to the ambient air and/or a condition of air pollution.

4. USGen New England, Inc. shall notify the Department in writing within 10 days after each activity listed below occurs:

   a) The date construction commences.
   b) The date construction is completed.
   c) The date Unit 1 SCR has passed acceptance testing (vendor guarantee).
   d) The date Unit 3 SCR and ARP have both passed acceptance testing (vendor guarantees).
   e) The date Unit 3 FGD has passed acceptance testing (vendor guarantee).

5. Notification as required by 40 CFR 60 Subpart Dc, Section 60.48c(a).

6. The use of wastewater from the Somerset POTW that contain VOCs and the transfer of ship-delivered limestone to the receiving hopper controlled by a wind barrier as dust control are subject to the reporting requirements contained in 310 CMR 7.02(2)(f).

## XII. TESTING REQUIREMENTS

1. The Applicant shall ensure that the proposed facility is constructed to accommodate the initial 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 a method approved by the Department in writing.

2. 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. The test protocol shall include a test matrix that will define emission control efficiencies and emission rates, as follows:

   <u>Unit 1</u>
   $NO_x$ (before and after SCR)
   $NH_3$ (after SCR)

   <u>Unit 3</u>
   $NO_x$ (before and after SCR)
   $SO_2$ (before and after FGD)
   $NH_3$ (before and after FGD)

3. The Applicant shall conduct initial emission compliance tests no later than 180 days after the dates specified in Sections XI.4.c, XI.4.d and XI.4.e. The emission compliance test program shall comply with the Department of Environmental Protection Guidelines for Source Emission Testing.

4. The Applicant shall conduct initial compliance tests to demonstrate that Unit 1 and Unit 3 are in compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd as applicable, and opacity) for the pollutants listed below. With respect to Unit 3, the Applicant shall conduct an initial compliance tests on the existing stack after SCR installation and the new FGD stack after FGD installation. If the installations of the SCR and FGD systems coincide, initial compliance testing shall be conducted on each of the two (2) stacks. Testing for the following pollutants shall be conducted at 100% of rated base load:

   a) Nitrogen Oxides ($NO_x$)
   b) Particulate Matter (PM)
   c) Sulfur Dioxide ($SO_2$)
   d) Ammonia ($NH_3$)
   e) Opacity

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. In accordance with 310 CMR 7.13 the Department may require additional emissions testing of the proposed facility at any time to ascertain compliance with the Department's Regulations and/or this Conditional Approval.

7. In accordance with 310 CMR 7.04(4)(a), the Applicant shall have Unit 1 and 3 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.

## XIII. GENERAL REQUIREMENTS

1. The Applicant shall properly train all personnel to operate the proposed facility and control equipment in accordance with vendor specifications and this Revised Conditional Approval.

2. All requirements of this Revised 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 in a convenient location (e.g., control room/technical library) and make them readily available to all employees and the Department.

4. The Applicant shall comply with all provisions of 310 CMR 6.00-8.00 that are applicable to this facility.

5. This Revised 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 Revised 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 dust, odor or sound conditions that cause or contribute to a condition of air pollution as defined in Regulations 310 CMR 7.01, 7.09 and 7.10.

8. Should asbestos remediation/removal be required as a result of this Revised 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 Revised 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 facility shall be constructed and operated in strict accordance with this Conditional Approval. Should there be any differences between the Applicant's Non-Major Comprehensive Plan Application (Application No. 4B02012, Transmittal No. W027692) and this Revised Conditional Approval, this Revised Conditional Approval shall govern.

12. All provisions contained in existing plan approvals and the Operating Permit concerning the subject facility issued by the Department to USGen New England, Inc, 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 (MEPA)

An Environmental Notification Form (EOEA No. 13022) was submitted to the Executive Office of Environmental Affairs, for air quality control purpose, pursuant to the Massachusetts Environmental Policy Act (MEPA) and 301 CMR 11.00 MEPA Regulations. The ENF was designated EOEA No. 13022.

On May 22, 2003, the Secretary of Environmental Affairs issued a Certificate on the ENF with a determination the project does not require the preparation of an Environmental Impact Report. Furthermore, in response to a Notice of Project Change the Secretary of Environmental Affairs issued a letter, dated August 23, 2004, indicating that no further review is required for the use of aqueous ammonia in place of the urea based system.

## XVI. LIST OF PERTINENT INFORMATION

| | |
|---|---|
| Application Title: | "310 CMR 7.02 Plan Approval Application as part of 310 CMR 7.29 Implementation at Brayton Point Generating Station" Revision 4 dated August 2004 (w/Revision 5 – August 2005 Replacement Pages) |
| Application Prepared by: | TRC Environmental Corporation |
| Attested to by: | Val F. Madden, P.E. No. 33713 |

Submitted by: Dominion
Date Submitted: August 22, 2005

## 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.