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PETITION NO. ~~979~~
377 A

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November 17, 2010

RECEIVED
NOV 17 2010
CONNECTICUT
SITING COUNCIL

Ms. Linda Roberts
Executive Director
Connecticut Siting Council
Ten Franklin Square
New Britain, CT 06051

Re: Petition No. 979; Petition for Declaratory Ruling

Dear Ms. Roberts:

I am writing on behalf of Bridgeport Energy, L.L.C. to provide you with an original and 20 copies of a Petition for Declaratory Ruling to modify the Decision and Order in Petition No. 377 for the Bridgeport Energy Generating Facility in Bridgeport, Connecticut to operate exclusively on natural gas. Also enclosed is a check in the amount of $625.00 for the filing fee.

If you have any questions, please feel free to contact me.

Sincerely,

Andrew W. Lord

Andrew W. Lord

Enclosures

cc: John Staikos, Esq.
Mr. Scott Weis

RECEIVED
NOV 17 2010
CONNECTICUT
SITING COUNCIL

PETITION NO. 979
377A

STATE OF CONNECTICUT
CONNECTICUT SITING COUNCIL

PETITION OF BRIDGEPORT ENERGY LLC FOR A DECLARATORY RULING TO MODIFY THE DECISION AND ORDER IN PETITION NO. 377 AT THE BRIDGEPORT ENERGY GENERATING FACILITY IN BRIDGEPORT, CONNECTICUT TO OPERATE EXCLUSIVELY ON NATURAL GAS	:	PETITION NO. 979 NOVEMBER 17, 2010

PETITION FOR DECLARATORY RULING

I. INTRODUCTION

Pursuant to Sections 4-181 and 16-50k of the Connecticut General Statues ("C.G.S.") and Sections 16-50j-38 to 16-50j-40 of the Regulations of Connecticut State Agencies ("R.C.S.A."), Bridgeport Energy, L.L.C. ("Bridgeport Energy") hereby requests, based on the change in conditions discussed herein, that the Connecticut Siting Council (the "Council") render a declaratory ruling modifying its approval of Petition No. 377 to allow the Bridgeport Energy electric generating facility (the "Facility") in Bridgeport, Connecticut to operate exclusively on natural gas and to eliminate the requirement to maintain the ability to operate on No. 2 fuel oil. C.G.S. § 4-181a(b) authorizes an administrative agency to modify a final decision on a showing of changed conditions.

Under Bridgeport Energy's current approval, it must maintain its ability to burn No. 2 fuel oil. However, Bridgeport Energy desires to eliminate the requirement to be capable of burning No. 2 fuel oil for two reasons. First, it no longer has the need for the ability to burn No. 2 fuel oil. Since the construction of the Bridgeport Energy facility was approved in 1997, several developments have occurred to increase the supply of natural gas such that the current supply of natural gas and pipeline capacity is sufficient to reliably serve New England's gas-fired generation fleet at a price that makes it uneconomic to operate on No. 2 fuel oil. Second, removing the provisions in Bridgeport Energy's air permit relating to operation on No. 2 fuel oil would be consistent with the Connecticut Department of Environmental Protection's ("DEP") air quality planning goals and standards for certain particulate emissions. The DEP has indicated to Bridgeport Energy that it is not opposed to such removal.

II. PROCEDURAL BACKGROUND

On July 7, 1997, The United Illuminating Company ("UI"), on behalf of Bridgeport Energy, submitted a petition to the Council for a declaratory ruling that modifying UI's Bridgeport Harbor Station by constructing a nominally-rated 520 MW combined cycle electric generating facility in Bridgeport, Connecticut, would not have a substantial adverse environmental effect and that no Certificate of Environmental Compatibility and Public Need would be required. At the time the petition was submitted (as reflected in the transcript of the public hearing for Petition No. 377), Connecticut and the region were facing serious electricity capacity shortages as the result of prolonged nuclear power plant outages. The project was proposed, in part, to provide critical additional generating capacity on an expedited basis. The facility, as originally proposed, was to operate primarily on natural gas with No. 2 fuel oil as a back-up in the event of a physical interruption or in the event that natural gas was not available at favorable prices. However, at the time that the Council was considering the petition, Bridgeport Energy had not determined how natural gas would be delivered to the site, and proposed to operate on No. 2 fuel oil until the gas supply could be finalized and constructed. When the Council approved the project on August 6, 1997, it included the following condition in its Decision and Order:

> "the project shall operate on natural gas except during curtailment of natural gas when such project may operate on No. 2 fuel oil as permitted by the Department of Environmental Protection."

On September 19, 1997, shortly after the generating facility was approved, Southern Connecticut Gas Company submitted to the Council a petition for a declaratory ruling for the approval of a natural gas distribution pipeline to serve the Bridgeport Energy facility. The Council approved the pipeline on November 12, 1997, thus securing the natural gas supply for the Bridgeport Energy project. On December 16, 1997, in a quarterly status report to the Council, Bridgeport Energy informed the Council that the construction of the No. 2 fuel oil system was being deferred and that Bridgeport Energy intended to run only on natural gas.

However, as more fully explained in a letter from Bridgeport Energy to the Council dated June 14, 1999 (attached as Exhibit 1), the Bridgeport Energy facility was constructed and permitted to allow future operation on No. 2 fuel oil. Certain components that allow oil-firing were constructed or incorporated into the design of the facility. For example, the turbines are capable of firing on natural gas or No. 2 fuel oil. The heat recovery steam generator stacks were designed to allow for a 30-foot extension to meet the permitted emission limits for operation on No. 2 fuel oil.

Additional space was built into the Selective Catalytic Reduction module for the additional catalysts that would be required for operation on No. 2 fuel oil. Finally, the facility obtained an air permit from the DEP that allowed operation on No. 2 fuel oil for approximately 60 days per year.

Although certain components are in place, a significant amount of work would need to be done to allow operation on No. 2 fuel oil. Specifically, to be able to operate on No. 2 fuel oil, Bridgeport Energy would need to increase the height of the exhaust stacks by at least 30 feet from 130 feet to 160 feet to meet the permit limits for No. 2 fuel oil. In addition, it would be necessary to construct the No. 2 fuel oil delivery, storage and control systems, including tank storage of at least 1.5 million gallons, install all new piping, pumping and control systems, perform extensive software upgrades and modifications, and make significant adjustments and additions to the burners. In addition, once the necessary equipment is installed, the turbines would need to be tested and commissioned for operation of No. 2 fuel oil.

On February 3, 2000, Bridgeport Energy submitted to the Council a "Natural Gas Curtailment and Oil-Firing Contingency Plan Study" (the "Study") to address the Council's concerns about potential electric supply reliability issues that could arise in the event of a curtailment of natural gas without No. 2 fuel oil as a back-up. The purpose of the Study was to provide information to evaluate electricity demands and natural gas supplies, and determine the likelihood that a curtailment of natural gas could cause electric system reliability problems. The Study also included an "Oil-Firing Contingency Plan" (the "Contingency Plan") that outlined the steps to be taken if certain indicators suggested a natural gas supply shortage could result in a curtailment. The Council approved the Contingency Plan on March 22, 2000.

III. NATURAL GAS SUPPLY IMPROVEMENTS

Under the terms of the Contingency Plan, Bridgeport Energy agreed to periodically review and analyze information regarding the supply and demand for natural gas in New England. If the analyses indicate that the capacity of the natural gas supply ("capacity") exceeds the demand for natural gas (the "capacity margin") by greater than two percent, then no further analysis or action is required. If the capacity margin is less than two percent, then the regional demand for electricity and the natural gas supply needed to meet that demand must be conducted. If the analysis reveals that the capacity of natural gas is greater than the capacity needed to meet the regional demand for electricity by more than two percent, then no further analysis is required. However, if that analysis indicates a capacity margin of less than two percent, then a further analysis of the state level electric supply and demand is to be analyzed. Again, if such analysis shows a reserve margin of greater than two percent, no further analysis is required. If the state level capacity margin is less than two percent, then Bridgeport Energy must take the steps needed to obtain any necessary permits to install and operate the No. 2 fuel oil systems, as described in the Contingency Plan.

In the Contingency Plan Study, Bridgeport Energy provided an analysis of the natural gas capacity margins in New England. For the years 1997 to 2001, the capacity margins were between 19 percent and 47 percent. Thus, no further analysis was necessary. On October 17, 2005, Bridgeport Energy submitted an updated analysis for the years 2003 through 2008. Under the most conservative set of calculations provided in the update, the lowest capacity margin was 62 percent (2004). These two reports illustrate two important points. First, the capacity margins have been, and are projected to be far in excess of the two percent margin that would trigger the implementation of the Contingency Plan. Second, the capacity margins are larger now than in the 1997 to 2001 timeframe.

By many accounts, the natural gas supply in the Northeast has improved dramatically over the recent years. As described in detail in R.W. Beck's "Final Report, Connecticut and New England Natural Gas and Power Infrastructure Supply Changes 1991 – Present," prepared for Milford Power Company, LLC, dated July 28, 2010 and submitted to the Council in connection with Docket No. 187,[1] there are a number of developments that have increased the reliability of the gas supply in Connecticut and New England, including the demonstrated viability of the Marcellus shale formation to produce significant new quantities of natural gas in close proximity to New England load centers. In addition, pipeline expansions, new liquefied natural gas facilities and improved pipeline transmission capacity have removed the supply constraints that existed in the late 1990's. In summary, based on historic projections and more recent studies, Bridgeport Energy does not envision the need to operate on No. 2 fuel oil for either reliability reasons or for economic purposes. Further,

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1 Docket 187 relates to the Milford Power electric generating facility in Milford, Connecticut. Milford Power is also seeking the Council's approval to decommission its fuel oil operation. The R.W. Beck report was submitted in support of that request.

Bridgeport Energy would have no obligation to do so under the terms of the approved Contingency Plan.

IV. AIR PERMITTING ISSUES AND REGULATORY CHANGES

Absent outside factors, Bridgeport Energy would not be seeking a modification of its Council approval. However, Bridgeport Energy recently met with representatives of the DEP's Bureau of Air Management to discuss modifications to the air permit to reflect the addition of controls for carbon monoxide emissions. At that meeting, the DEP informed Bridgeport Energy that the agency was not opposed to removing the terms of the permit relating to the oil-firing capability. The DEP's reasons in support of removing the oil-firing aspects of the permit relate to federal regulatory requirements for particulate matter, specifically, solid matter or liquid droplets with an aerodynamic diameter of 2.5 microns or less ("PM 2.5"). These federal regulatory requirements developed over a period of several years following the approval of the facility. Under the regulations, DEP was required to submit State Implementation Plans for PM 2.5 in 2008, which plan was to include control measures sufficient to achieve compliance with the National Ambient Air Quality Standards by April 2010.

Under the DEP's State Implementation Plan, the DEP must model the <u>potential</u> emissions from operations on oil, not the actual emissions.[2] In other words, the DEP must input the emissions from the facility as if it were operating for approximately

2 When used in the context of emissions modeling, "potential emissions" refers to the total emissions that could result from operating at the maximum permitted level, not the actual emissions. Bridgeport Energy's air permit allows operation on No. 2 fuel oil for approximately 60 days per year.

60 days per year on No. 2 fuel oil, even though it is not equipped to do so at the present time. When modeled using the inputs from using No. 2 fuel oil, the potential emissions of PM 2.5 are an issue for DEP in an area that is non-attainment for PM 2.5, like Bridgeport. In addition, whenever DEP initiates future air quality planning, the fact that Bridgeport Energy has the <u>potential</u> to operate on No. fuel oil causes complications for increment modeling. Finally, when future developments are proposed in the vicinity of Bridgeport Energy that require an air permit, those facilities must also do modeling that includes Bridgeport Energy's <u>potential</u> emissions. In summary, Bridgeport Energy's permit conditions "reserve" a certain level of emissions for operating on No. 2 fuel oil, such that those potential emissions are unavailable for other potential sources and must be taken into consideration in DEP's planning efforts.

Finally, if Bridgeport Energy is not able to remove the No. 2 fuel oil-firing capabilities from its air permit, DEP will require Bridgeport Energy to engage in a lengthy analysis of the Best Available Control Technology ("BACT") for PM 2.5 and to perform all new modeling for emissions from the facility. In addition to the time and expense associated with these activities, the results could have serious implications for the types of additional controls that would be required.

V. <u>CONCLUSION</u>

Based on the fact that natural gas supplies have been sufficient to reliably supply the generation fleet in Connecticut and New England and because recent improvements and developments have increased the supply of natural gas to the region, it is unnecessary for Bridgeport Energy to maintain the ability to operate on No. 2 fuel oil for either reliability or economic reasons. Under the Oil-firing Contingency Plan, it is extremely unlikely that the need to operate on No. 2 fuel oil will ever be triggered. Accordingly, it is neither prudent nor practicable for Bridgeport Energy to "reserve" the potential emissions allowances for operation on No. 2 fuel oil. Continuing to do so raises significant issues for Bridgeport Energy, the DEP and any future projects. Further, there is no justification for the time and expense associated with performing a BACT analysis and all new air modeling for operation on No. 2 fuel oil when it is very unlikely that the facility will ever need to operate on No. 2 fuel oil. Unfortunately, the subject permit terms cannot be removed from the permit unless the Council agrees to remove the requirement to maintain the ability to operate on No. 2 fuel oil.

Therefore, in accordance with C.G.S. § 4-181a(b), and as described above, Bridgeport Energy respectfully requests that the Council consider i) the significant improvements in the natural gas supply in the region in the thirteen years since the project was approved, and ii) the changes in DEP's air regulations, as "changed conditions" that justify removing the requirements to maintain the ability to operate on No. 2 fuel oil from the Decision and Order in Petition No. 377 and allow Bridgeport Energy to operate exclusively on natural gas.

VI. NOTICE AND COMMUNICATIONS

Finally, in accordance with R.C.S.A. § 16-50j-39, the names, addresses and telephone numbers of the persons to whom correspondence or communications in regard to this Petition are to be directed are:

John Staikos, Esq.
LS Power Equity Advisors, LLC
1700 Broadway, 35th Floor
New York, NY 10019
Telephone: 212-615-3456
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E-mail: alord@murthalaw.com

Respectfully submitted,

BRIDGEPORT ENERGY LLC

By Andrew W. Lord

Andrew W. Lord

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Telephone: (860) 240-6180
Facsimile: (860) 240-6150
Its Attorney

Bridgeport
ENERGY

Bridgeport Energy LLC
10 Atlantic Street
Bridgeport, CT 06604

June 14, 1999

Joel M. Rinebold
Executive Director
State of Connecticut
Connecticut Siting Council
Ten Franklin Square
New Britain CT 06051

Re: **Petition No. 377 - Bridgeport Energy LLC**

Dear Mr. Rinebold:

This letter is in response to your letter to Ted Manes dated April 16, 1999. In that letter you referenced Bridgeport Energy's ("BE") March 30, 1999 Quarterly Progress Report and the Council's staff inspection of the BE site on April 5, 1999. In your letter, you requested additional information concerning BE's "...capability to use low sulfur No. 2 oil during times of natural gas curtailment to ensure reliability of the facility, consistent with the Council's Decision and Order dated August 6, 1997."

As you know, when Petition No. 377 was submitted to the Council in the summer of 1997, it was not clear how the gas would get delivered to the Site, i.e., would the gas transportation be marine-based or land-based. In addition, there was genuine concern that given those uncertainties and the potentially contentious gas pipeline permitting process, gas might not have been able to have been delivered to the Site in time to commission the facility for operation during the Summer of 1998. It was believed that there may be capacity shortages during that summer throughout the State of Connecticut and the Region. For these reasons, it was especially important to plan and permit for both sources of fuel, which is reflected in the testimony offered during the public hearing on the Petition. Given possible market fluctuations and other considerations, it is important to continue to be able to run the facility on both fuel sources, which is why BE has never made the permanent decision to eliminate oil as a possible fuel supply. However, at this time, BE has elected not to construct all of the oil systems.

Although we believe this decision is consistent with both the terms of the Council's Opinion, and Decision and Order, and the spirit of the testimony provided in the hearing on the Petition, we want to work with the Council to ensure that even if there is a natural gas curtailment, there will be ample electricity generated for Connecticut's needs. To that end, we have described below what oil facilities BE has planned for and constructed, and what steps BE will take to evaluate under what circumstances a natural gas curtailment may occur, and what steps BE would take in the event of such a curtailment if the consequences of BE's not being able to run on oil during such a curtailment would cause shortages in Connecticut.

Systems to Run on No. 2 Oil

BE has not made a permanent decision not to run the facility at any time in the future on oil. Instead, we have made a decision that for the near-term, based upon our evaluation of possible curtailments and other factors, all of the oil systems will not be constructed. Although the oil tank and certain other oil delivery facilities have not been constructed, it is important to note that during the construction process of the BE facility, certain critical construction and operational decisions to support the later possible addition of the remaining oil systems to the facility have been made. For example, the exhaust stack pilings and foundations were designed to support the requirement in the DEP Air Permits to Operate the facility in combined cycle mode (the "Air Permits") for 160 foot stacks if the facility runs on oil. The electrical power supply capacity and breakers can support running the facility on oil. BE applied for and obtained air permits to allow operation on No. 2 oil, and the Air Permits authorize operation on oil for thirty (30) days per year. Furthermore, BE purchased sufficient VOC offsets required by the Air Permits to cover operating on oil.

Additional Factors/Systems to Run on No. 2 Oil

The above-referenced steps that have been taken in order to run on oil are the most significant steps in terms of time and complexity. There are additional steps that would need to be taken in order to run the BE facility on oil. For example, the oil auxiliary systems and structures would need to be designed, purchased, constructed, and commissioned. At the same time as the design of those systems is proceeding, the City of Bridgeport site plan approval for siting and construction of the oil tank would need to be applied for, and a stack testing protocol would need to be submitted to the DEP for approval. Once constructed, BE would need to go on an outage so that the oil systems could be tied in and the facility could be commissioned on oil.

Scope of Study Regarding Natural Gas Curtailment

BE proposes to prepare a scope of study in order to evaluate the circumstances under which a natural gas curtailment may occur in this Region, and under what circumstances and when BE would implement the steps outlined just above to enable the facility to run on oil. The scope of study would include a history of curtailments, a description of the circumstances under which BE would design, permit, construct and commission the additional oil facilities addressed above, and a schedule for implementation of same. We propose that we prepare a draft of the scope of study for submittal to the Council by July 23, 1999 for the Council's informal review and comment.

Background to Decision to Run on Natural Gas

It may be useful to frame the historical context of BE's decision to defer construction and commissioning of all of the oil systems. There were a number of factors that BE considered in the course of its decision-making process to defer the construction of all of the systems necessary to run the plant on No. 2 oil. Those factors included the eventual certainty that the gas pipeline would be constructed in time to deliver gas to the Site for simple cycle (Phase 1) operation during the summer of 1998, and the fact that natural gas is cleaner burning, and, therefore, preferable from an environmental point of view.

In the December 16, 1997 Status Report to the Council, we informed the Council that "....construction of the fuel oil system was being deferred..." and that BE intended to run the facility only on natural gas for both the simple- (Phase 1) and combined- (Phase 2) cycle phases of operation. Part of the decision-making to defer the construction of the additional systems necessary to run the plant on oil in that time frame centered on the challenge to our air permits application. On September 25, 1997, the DEP issued its tentative determination to issue the Air Permits to Operate the facility on both natural gas and oil. In late-October 1997, several citizens' groups challenged the tentative determination. The public hearing on the challenge was held on December 22, 1997. The citizens were raising issues involving the older, "dirtier" units in the State that run on oil (the so-called "Filthy Five"). As such, in addition to several other factors militating in favor of running the plant only on natural gas, it appeared reasonable, given the citizen challenge to the proposed draft BE dual-fuel air permits and to the oil-fired units in the State of Connecticut, that BE should run the plant only on natural gas. Ultimately, the Permits were issued authorizing the use of gas or oil (oil being limited to 30 days a year). In this context, we think that it may have been clearer in the mid-December 1997 time frame to have stated in the December Report to the Council that the *decision* regarding the timing of the construction of all of the oil systems was being deferred, and not that the construction of all of the facilities was being deferred, which may have been interpreted to imply that construction of all of the oil systems would occur in the near term.

As we believe the Council is well-aware, BE honored its commitment to the Council, and the Departments of Environmental Protection and Public Utility Control and worked extremely hard to build the simple cycle facilities in an amazing nine months to ensure that there was available capacity during the summer of 1998. We have continued to work hard to ensure that the combined cycle facilities were ready for this summer. We would like to take this opportunity to state that we will continue to work hard to continue to partner with the Council and other interested agencies to ensure that Connecticut is not harmed by electricity outages. We hope that the information contained in this letter is helpful to you and the Council members, and look forward to working with you toward the development of a scope of study on curtailment.

If you have any questions, or require any additional information, please contact me.

Very truly yours,

David A. Gillespie

c: Abbie Eremich, Esq.

Bridgeport
ENERGY

Bridgeport Energy LL
10 Atlantic Street
Bridgeport, CT 06604

October 17, 2005

S. Derek Phelps
Executive Director
State of Connecticut
Connecticut Siting Council
10 Franklin Square
New Britain, CT 06051

Dear Mr. Phelps:

Pursuant to our meeting at your office on October 13, 2005, one original and twenty (20) copies of Bridgeport's Oil Firing Contingency Plan are submitted in accordance with the Connecticut Siting Council letter dated June 14, 1999. Bridgeport appreciated your consideration in this matter and will submit its annual reports in a timely manner in the future.

If you have any questions please call me at (713)-627-4600.

Respectfully,

Brad Porlier

Brad Porlier
Managing Member

Bridgeport Energy LLC

Natural Gas Curtailment and

Oil Firing Contingency Plan Study

Submitted by
Bridgeport Energy LLC

March 11, 2005

Section 1 – Introduction and Background

This study is submitted in accordance with the terms of the Bridgeport Energy LLC ("Bridgeport") letter to the Connecticut Siting Council (the "Council") dated June 14, 1999 ("the Letter"), the draft Scope of Study dated July 23, 1999 and is generally consistent with the initial Bridgeport Study submitted on February 3, 2000. The purpose of the study is to provide information to evaluate whether the amount of future available natural gas pipeline capacity could result in electric system reliability issues in Connecticut such that Bridgeport should implement what is referred to as the Oil Firing Contingency Plan ("Contingency Plan"). The study focuses on long-term projected changes to supply and demand and does not address unexpected, short-term pipeline or transmission unavailability. If it is determined that regional gas supplies are inadequate to support the demands of existing users and gas-only fueled generating facilities, Bridgeport will address the Oil Firing Contingency Plan.

The study is organized in five sections: Section 1 provides an introduction and background. Section 2 addresses the recent activity concerning reliability of the electric and natural gas infrastructure in New England including the January 2004 "Cold Snap." Section 3 addresses the methodology by which Bridgeport analyzes gas supply and demand trends to determine if the Contingency Plan shall be considered. Section 4 describes the steps and standards by which Bridgeport Energy would implement the Contingency Plan, if required. Section 5 outlines the proposed timetable for updating the study.

Section 2 – Reliability of the Electric Infrastructure

The region's pipelines deliver gas to New England from supply basins from the U.S. Gulf Coast, from Western Canada, and from Eastern Canada. The interstate and intrastate pipeline companies serving New England include: Algonquin Gas Transmission, Granite State Gas Transmission, Iroquois Gas Transmission System, Maritimes & Northeast Pipeline, Portland Natural Gas Transmission System, and Tennessee Gas Pipeline Company. Total pipeline deliverability is approximately 4 Bcf/day.[1] The majority of New England's natural gas is delivered by two major interstate systems through the Algonquin Gas Transmission system, and the Tennessee Gas Pipeline system. Together these two pipeline systems comprise nearly 80% of the region's pipeline deliverability.[2] The report notes that in the last thirteen years, New England added three new pipeline systems delivering gas from supply basins in Canada including Western Canada supplies using Iroquois Gas Transmission system in 1992 and Portland Natural Gas Transmission system in 1999, and Eastern Canada's Sable Island offshore gas supplies from the Maritimes & Northeast Pipeline in 2000. All pipelines and distribution companies are interconnected in a network to form a comprehensive delivery system. Bridgeport Energy generates power from natural gas provided to the facility through a third party tolling agreement with Duke Energy Trading & Marketing, LLC ("DETM"). The gas is supplied utilizing the Iroquois Gas Pipeline system and Southern Connecticut Gas system.

[1] Northeast Gas Association, "Northeast Natural Gas Market Update," January 2005
[2] Ibid.

New England is the site of one of four operating import terminals in the US for liquefied natural gas ("LNG"). The terminal is owned by Tractebel LNG North America and operated by its subsidiary, Distrigas of Massachusetts Corp. ("DOMAC"). LNG is imported primarily from Trinidad & Tobago in the Caribbean and delivered by tanker to the Distrigas terminal at Everett, Massachusetts. The terminal has pipeline interconnections as well as connections with a major local distribution company ("LDC") and a major power plant. LNG is supplied to various LDC satellite storage tanks from trucks that load at the DOMAC terminal. DOMAC recently increased the vaporization capability at its terminal from 435 MMcf/d to a maximum of 1 Bcf/day and has daily sendout by truck of another 100 MMcf/day.[3] Several proposed LNG projects are under active development in New England and the Maritimes. LNG is expected to be a significant contributor to incremental new gas supplies for New England. New in region LNG facilities will also provide additional critical supply reliability in the future. For purposes of this study, no new LNG supplies are expected to be completed prior to 2009 and therefore are not included.

In January 2004, New England experienced unusually severe weather and high electricity demand conditions. These are precisely the kinds of conditions that are of concern to the Siting Council and the electric industry. Extremely low temperatures, very high demand for electricity, and peaking conditions in the natural gas markets occurred simultaneously during January 14-16, 2004 ("January Cold Snap"). During the January Cold Snap the gas market set a new delivery record. New England LDCs experienced a record peak day sendout of 3.8 Bcf on January 15, 2004, 12% above the previous peak day set in January 2000.[4] New England peak electric demand reached 22,817 MW. During the period electric reserve margins became very low, placing the electric system at a point where demands nearly exceeded supplies. This event prompted investigations by ISO New England and FERC into market and system performance during severe cold weather conditions. The conclusion of the investigations indicated that there were no electric service interruptions and firm gas load obligations were served. However, improvements in the scheduling of electric resources and coordination between the electric industry and gas industry were needed to improve reliability.

Following the January Cold Snap, in the fall of 2004, ISO-NE adopted OP-20 "Cold Weather Event Operations" to address the problems which the market encountered in January 2004. This includes provisions for changing scheduling of the power markets to align with the gas market schedule, lowering of load demand in certain circumstances and requiring dual-fueled generation to switch to oil firing if required for system reliability. Bridgeport and its affiliates are active participants with ISO New England and various task forces to recommend and seek implementation of improvements to the processes and systems affecting electric system reliability and gas pipeline operations.

Between 1998 and 2004 New England experienced substantial growth in electric generation utilizing natural gas. Much of this generation is capable of firing on fuel oil in addition to natural gas. Gas pipeline systems continue to expand and improve deliverability. As a result of

[3] Northeast Gas Association, "Regional Natural Gas Supply & Deliverability", presentation to Cold Snap Task Force, Marlborough, MA, June 18, 2004.

[4] Ibid.

high capacity margins and poor economics, gas fired electric supply growth has slowed with the cancellation or delay of many proposed gas fired generation projects. These trends are expected to increase gas supply delivery margins in the short term as gas supplies increase with a modest growth in gas demand.

Section 3 – Gas Supply and Demand Study Methodology

Gas and electric system supply and demand conditions have been studied using a multi-step process. The first step includes an overview of gas supply and demand projections. Appendix A provides gas supply and demand data used in the study. Appendix B includes a listing of electric generation projects which have been fully permitted that are considered for the study. Appendix C provides a list of proposed gas supply infrastructure projects considered in future supply analysis.

Consistent with the study previously submitted to the Siting Council, Bridgeport has followed the approach outlined below:
(i) Compare peak day gas demand projections with available supply capacity. Demand will include all residential, commercial, industrial, and power production uses. Supplies will include both pipelines and LNG storage. If gas supply capability exceeds projected demand by more than 2%, the analysis will be concluded and the results will be forwarded to the Council for review.
(ii) If the foregoing review results in gas supply margins of less than 2%, then the regional electric supply and demand situation will be evaluated further. Peak winter loads and planning reserve margins will be assessed to determine what amount of electric generation capacity can be considered "surplus" (i.e. installed megawatts in excess of load plus reserves.) Surplus generation gas demand will be deducted from the pipeline demand previously calculated. This value will represent the amount of gas-fired generation capacity that could be curtailed without having an impact on electric reliability. If, upon the removal of the natural gas demand created by surplus generating capacity, gas supply capability then exceeds demand by greater than 2%, the analysis will be concluded. The results will then be forwarded to the Council for review.
(iii) If the foregoing review results in gas supply margins of less than 2%, the statewide electric supply and demand balance will be assessed. Additionally, this step will evaluate the load relief available from implementation of ISO-NE OP-4 Action During a Capacity Deficiency and OP-20 "Cold Weather Event Operations". If, upon completion of the state level analysis, gas supply capability then exceeds demand by greater than 2% the analysis will be concluded. The results will be then be forwarded to the Council for review.
(iv) If the foregoing analysis indicates reserve margins of less than 2%, the Contingency Plan will be addressed.

Natural Gas Supply/Demand Analysis 2003 – 2008

The Table 1 depicts the average daily demand in 2003 of end-use gas consumption for New England. 2003 is the most recent year for which complete data is available (see Appendix A for 2001-2003 data by sector). The average daily demand is calculated by dividing the total annual demand by 365.

Table 1 **New England Natural Gas Consumption - 2003**
Average Daily Demand (Mcf/d)

State	Power Generation	All Others	Total
CT	116,627	296,230	412,858
ME	166,208	25,499	191,707
MA	463,704	772,216	1,235,321
NH	78,430	70,789	149,219
RI	115,096	98,805	213,901
VT	82	22,893	22,975
TOTAL	**940,148**	**1,286,433**	**2,226,581**
% of Total	42.2%	57.8%	

Source: www.eia.doe.gov, "Natural Gas Annual 2003", issue date December 2004: Natural Gas Delivered to Consumers by State and Sector (Table 16)

Table 2 shows the projected growth rate for natural gas consumption in New England according to the Northeast Gas Association "Northeast Natural Gas Market Update, April 2004". In that report, the overall annual natural gas growth rate was projected at 1.6% through 2025[5].

Table 2 **New England Natural Gas Consumption: Projected Growth – 2004-2008**
Average Daily Demand (Mcf/d)

Year	Power Generation	All Others	Total
2004	940,148	1,286,433	2,226,581
2005	955,190	1,307,016	2,262,206
2006	970,473	1,327,928	2,298,401
2007	986,001	1,349,175	2,335,176
2008	1,001,777	1,370,762	2,372,539
		Annual Average Growth Rate	1.6%

Because generation is typically built in large discrete blocks of capacity, noticeable incremental increases result in the gas demand profile of the power generation sector. Appendix B shows the expected natural gas demand increases from the generation projects through 2008 which are fully

[5] The NEGA report actually cites the projection as being performed by the Energy Information Administration (EIA).

permitted in the northeast region. Any project which has not yet begun construction is assigned a 24-month lead time based on Bridgeport's construction experience. Note that permitted power projects may not ultimately achieve commercial operations. By including the demand from fully permitted power projects, the revised projected growth rate can be extrapolated for the power generation sector. Table 3 restates the generation demand growth by including the non-power growth rate with the demand of the generation projects shown in Appendix B.

Table 3 **New England Annual Average Natural Gas Consumption: Projected Growth – 2004-2008 Including Permitted Power Projects** (Units: Mcf/d)

Year	Power Growth	Power Generation	All Others	Total Demand	Pipeline Capacity	Capacity Margin*
2003	0.0%	940,148	1,286,433	2,226,581	4,000,000	80%
2004	9.7%	1,031,540	1,307,016	2,338,556	4,300,000	84%
2005	0.1%	1,032,540	1,327,928	2,360,468	4,385,000	86%
2006	9.4%	1,129,540	1,349,175	2,478,715	4,670,000	88%
2007	0.0%	1,129,540	1,370,762	2,500,302	4,670,000	87%
2008	0.0%	1,129,540	1,392,694	2,522,234	4,770,000	89%
	3.7%	Compound Annual Growth Rate				

See "Appendix B" for Power Generation Projects for 2003-2008
*Capacity margin is Available Pipeline Capacity divided by Total Demand

Table 3 indicates that the compound annual growth rate from 2003 to 2008 in the power generation sector to be 3.7% vs 1.6% in overall long-term growth forecast by EIA.

Also shown in Table 3 is the anticipated pipeline capacity for the Northeast region during the referenced period. This is used to determine the projected capacity vs demand through 2008. The lowest the projected excess capacity margin of 80% significantly exceeds the 2% study requirement.

Appendix C lists the natural gas pipeline projects that are expected to increase pipeline deliverability through 2008. Table 3 assumes that the daily gas demand is met solely through pipeline deliverability. However, the Northeast Gas Association reports that LNG supplies approximately 15% of the Northeast annual gas supply and approximately 30% of peak day supply[6]. These facilities include:

Existing LNG Storage		Vaporization Capacity
DOMAC	3.5 Bcf	1000 Mcf/day
LDC system	15.1 Bcf	1257MMcf/day

By accounting for 15% of the total demand served by LNG deliveries, the new capacity margin for natural gas deliverability served by the pipelines increases to over 100% through 2008. Table 4 illustrates this point.

[6] Northeast Gas Association, "The Outlook for Natural Gas in the Northeast for the Winter-Heating Season, 2004-05", December 20, 2004 Update.

Table 4 **New England Natural Gas Annual Average Consumption Less LNG Served Load: Projected Growth – 2003-2008** (Units: Mcf/d)

Year	Total Demand	LNG Supplies	Net Demand	Available Capacity	Capacity Margin
2003	2,226,581	333,987	1,892,594	4,000,000	111%
2004	2,338,556	350,783	1,987,772	4,300,000	116%
2005	2,360,468	354,070	2,006,398	4,385,000	119%
2006	2,495,715	374,357	2,121,358	4,670,000	120%
2007	2,608,022	391,203	2,216,818	4,670,000	111%
2008	2,720,674	408,101	2,312,573	4,770,000	106%

In January 2004, New England experienced unusually severe weather, high electricity demand, and a tight supply of natural gas. On January 15, 2004 a record peak hour demand of 22,817 MW was reached[7]. Also on that day, New England LDCs reached a new peak day send out of 3.8 BCF compared with 3.4 Bcf reached on January 17, 2000[8]. For conservatism, the study has utilized the 3.8 Bcf/d, "extreme" peak sendout which is substantially higher than normal peak day demands.

Table 5 uses the peak day demand as total daily demand because the average daily demand does not recognize the effect of peak day requirements on the supply system. As previously noted, approximately 30% of peak day demand can be supplied by LNG in New England. For 2004, peak day demand of 3.8 Bcf less the 30% LNG supplied demand yields an equivalent pipeline gas demand of 2.66 Bcf/d and when compared with pipeline supplies results in a capacity margin of 61.7%. Assuming peak day demand will continue to grow at 1.6%, the capacity margin through 2008 remains above 60%.

Table 5 **New England Natural Gas Consumption: Projected Peak-Day Demand Less LNG Served Load – 2004-2008** (Units: Mcf/d)

Year	Peak Day Demand	LNG Supplies	Net Demand	Available Capacity	Capacity Margin
2004	3,800,000	1,140,000	2,660,000	4,300,000	61.7%
2005	3,860,800	1,158,240	2,702,560	4,385,000	62.3%
2006	3,922,573	1,176,772	2,745,801	4,670,000	70.1%
2007	3,985,334	1,195,600	2,789,734	4,670,000	67.4%
2008	4,049,099	1,214,730	2,834,370	4,770,000	68.3%

Source: Northeast Gas Association, "Regional Natural Gas Supply & Deliverability", June 30, 2004
Historical New England Peak Day Demand was 3.8 Bcf on January 15, 2004

[7] Connecticut Siting Council: "Review of the Connecticut Electric Utilities Ten-Year Forecasts of Loads and Resources 2004" pg 17.
[8] Northeast Gas Association: "Regional Natural Gas Supply & Deliverability", New England Council Natural Gas Forum, June 30, 2004.

Conclusion

The foregoing data indicates that in the peak day case that gas supply capacity margins exceed the 2% study threshold. As such, Bridgeport should not do further studies nor implement the Contingency Plan.

Section 4 – Oil-Firing Contingency Plan

In the event oil firing installation would be required, the following sections outline, at a very high level, the process of approvals, equipment installation and operations necessary to implement oil firing capability at the Bridgeport Energy site. This process is expected to take approximately 24 months. The installation of the oil firing equipment will trigger an emissions increase of particulate matter according to New Source Review ("NSR"). As a result, Bridgeport will be required to seek a new Prevention of Significant Deterioration ("PSD") air permit which will include air modeling and best available control technology ("BACT") analysis. A PSD permit is a type of permit issued to major sources (or major modifications of existing major sources) in areas that are classified as attainment for the National Ambient Air Quality Standards ("NAAQS"). NSR is the program that covers the issuance of major source permits in both attainment and non-attainment areas.

The additional air particulate emissions, construction of oil tank and truck offloading facilities, trucking operations, etc. are anticipated to have an impact to the local community. Permitting efforts are therefore anticipated to have significant public input and scrutiny.

Required Approvals

Air Permitting Activities and Considerations:

Authority to install oil firing equipment no longer exists. A PSD application will be required to permit the installation of oil firing equipment. Modifications to the permit will require public notification and public comment. During this process a public hearing may be requested.

may not be correct – may simply require update BACT + model

Asthma sensitivity in this area will be addressed.

A PSD application is required to address the following review criteria:

- Potential Emissions – The potential emissions from Bridgeport must be evaluated against the current actual emissions from the facility.
- Modeling analysis – the emissions from the modified source will be evaluated utilizing an approved computer model. The results of this modeling will predict the impact on the ambient air quality by the proposed modification. In addition to modeling the emissions from the proposed modified source, the analysis requires that the potential emissions from all permitted sources be evaluated, against the NAAQS.
- BACT analysis – requires a top down approach for evaluating emissions control systems. The available control systems are evaluated based on proven technology and if it is economically achievable. The cost of retrofitting a control system may be considered when conducting the cost analysis.

Previous stack height permitted increase to 160 ft may no longer be valid. New stack height to be determined by air modeling results.

Continuous emissions monitoring system and Data Acquisition and Handling System require opacity monitoring and PM-10 limits must be met.

Selective catalytic reduction review and impacts assessed.

Water Permitting Activities and Considerations

Spill Prevention Controls and Countermeasures Plan as well as the Storm Water Pollution Prevention Plan will require major revisions.

Changes to plant stormwater system and oil firing facilities for spill controls will be required.

Water requirements for a new water injection system to reduce nitrous oxides emissions must be evaluated to determine need for additional demineralized water system capacity.

Water purchase arrangements must be reviewed and addressed with city.

Community input on right to know requirements for chemical storage may be required.

Homeland Security and PSEG (neighboring Bridgeport Harbor power plant) Considerations

Potential requirement for additional security measures.

City of Bridgeport Approvals and Considerations

City Planning and Zoning Commission approvals are required, consideration will include:

- Visual impact of the fuel tank
- Trucking impacts of eight or more supply trucks per hour
- Security of facilities, tank will abut neighboring houses
- Proximity to the existing natural gas measuring station
- Cumulative impact on community to include the proposed new United Illuminating 345 kV Singer Substation and related additional transmission lines
- New flammable liquids storage permit from the City, right-to-know requirements addressed
- Impacts to the community during construction must be considered including traffic, noise, dust control, safety, etc.

Review by Local Emergency Planning Committee for volume of fuel oil stored on site

Installation and Testing

Once approvals have commenced Bridgeport will issue preliminary plans and specifications for:

- Fuel oil tanks, storage related equipment
- Fire fighting equipment
- Pumps, instrumentation, piping, electrical, etc.
- Truck offloading facilities
- Exhaust stack height increase and emissions monitoring
- Turbine modifications including dual fuel burners, fuel injection equipment, modified control combustion and fuel systems, interconnection piping and wiring
- NOx water injection system for combustion turbines
- Emissions monitoring hardware and software modifications

Final approval of plans and specifications will be subject to final approvals by DEP and the City of Bridgeport.

Selection of engineering and construction contractors will occur during the process.

Selection of final vendors will occur after final plans and specifications are issued and bid packages are issued and submitted to Bridgeport.

Installation is expected to take approximately six months after final approvals.

Commissioning and testing is expected to take 2 months.

Operations

Personnel training during installation and testing will occur.

Periodic operations with oil is expected to occur for testing, maintenance, reliability reasons or economic reasons.

Fuel oil offloading and demineralized water requirements will trigger review for supplemental staffing during periods of use.

Integrated Contingency Plan (ICP) will require review, modification and training of personnel.

Section 5 – Analysis Update Schedule

Consistent with the Siting Council requirements, Bridgeport will perform an annual review (or such a period as Bridgeport and the Council otherwise agree) of the natural gas supply and demand projections using updated assumptions. The study horizon will be three years, consistent with past practices. This review will utilize updated data including the Council's Review of the Connecticut Electric Utilities Ten-year Forecasts of Loads and Resources, the Energy Information Administration, the Northeast Gas Association, New England Governor's Conference, Inc. as well as proprietary competitive intelligence.

used new Load data

Appendix A: Average Daily Natural Gas Consumption: 2001-2003 (mcfd)

2001	CT	ME	MA	NH	RI	VT	Total
Residential	112,389	2,614	292,153	18,663	49,142	7,449	482,411
Commercial	121,584	7,238	168,978	20,134	35,090	6,775	359,800
Industrial	70,197	29,942	222,422	23,795	16,786	7,115	370,258
Vehicle	403	0	342	3	104	3	855
Electric Power	88,112	219,299	263,819	1,444	160,047	318	733,038
Total	392,685	259,093	947,715	64,038	261,170	21,660	1,946,362
Electric Power	88,112	219,299	263,819	1,444	160,047	318	733,038
All Others	304,573	39,795	683,896	62,595	101,123	21,342	1,213,323
Total	392,685	259,093	947,715	64,038	261,170	21,660	1,946,362

2002	CT	ME	MA	NH	RI	VT	Total
Residential	110,345	2,893	299,395	18,964	48,068	7,564	487,230
Commercial	111,055	14,156	177,433	24,022	31,419	6,767	364,852
Industrial	79,592	10,049	235,482	22,066	12,205	8,452	367,847
Vehicle	411	0	345	3	107	3	868
Electric Power	178,247	248,682	353,019	3,003	147,849	101	930,901
Total	479,649	275,781	1,065,674	68,058	239,649	22,888	2,151,699
Electric Power	178,247	248,682	353,019	3,003	147,849	101	930,901
All Others	301,403	27,099	712,655	65,055	91,800	22,786	1,220,797
Total	479,649	275,781	1,065,674	68,058	239,649	22,888	2,151,699

2003	CT	ME	MA	NH	RI	VT	Total
Residential	125,005	3,318	345,537	21,778	55,277	8,542	559,458
Commercial	106,192	13,099	195,485	26,904	31,208	7,553	380,441
Industrial	64,529	9,082	230,773	22,104	12,192	6,792	345,471
Vehicle	507	0	425	3	129	3	1,066
Electric Power	116,627	166,208	463,704	78,430	115,096	82	940,148
Total	412,860	191,707	1,235,923	149,219	213,901	22,973	2,226,584
Electric Power	116,627	166,208	463,704	78,430	115,096	82	940,148
All Others	296,233	25,499	772,219	70,789	98,805	22,890	1,286,436
Total	412,860	191,707	1,235,923	149,219	213,901	22,973	2,226,584

Source: Energy Information Administration, Natural Gas Annual 2003; "Summary Statistics for Natural Gas", issued December 2004; www.eia.doe.gov

Appendix B - Permitted New England Power Generation Projects (2003 - 2008)

Year	Project	Location	MW	Gas Req'd (mcf/d)	Status	Cumulative
2003	Project	Location	MW	Gas Req'd (mcf/d)	Status	Cumulative
			Total Gas 2003	0		
2004	Project	Location	MW	Gas Req'd (mcf/d)	Status	
	Milford Ph 1 PDC El Paso	Milford, CT	272	45,696	Completed -- in service	
	Milford Ph 2 PDC El Paso	Milford, CT	272	45,696	Completed -- in service	
			Total Gas 2004	91,392		91,39
2005	Project	Location	MW	Gas Req'd (mcf/d)	Status	
	Durham	Strafford, NH	7.5	1,000	Under construction -- online 11/2005	
			Total Gas 2005	1,000		92,39
2006	Project	Location	MW	Gas Req'd (mcf/d)	Status	
	Towantic Energy - Oxford	Oxford, CT	500	84,000	(see Note 1 & 2 below)	
	Loring AFB Central Heat/Cogen	Limestone, ME	79	13,000	Early development (3/2006); see Note 2	
			Total Gas 2006	97,000		189,39
2007	Project	Location	MW	Gas Req'd (mcf/d)	Status	
				0		
			Total Gas 2007	0		189,39
2008	Project	Location	MW	Gas Req'd (mcf/d)	Status	
			Total Gas 2008	0		189,39

Note 1 Advan Development (6/26/06) - Calpine is seeking PPAs prior to construction. Calpine renegotiated deal with town of Oxford where Calpine will pay $58MM in taxes in return for a softer deadline for payments to begin (now 2007)

Note 2: Since construction of these projects has not begun, online dates may not be realized until 2007 or later

Source: Platt's NEWGen Database

Appendix C: New England - Natural Gas Pipeline Projects/Proposals (2003 - 2008)

Year	Project	Company	Description	Status
2003	Maritimes & Northeast Pipeline Phase III Expansion; Algonquin Gas Hubline	M&NE Pipeline/ Algonquin Gas Trans (Duke Energy)	Approx 25 miles of 30"pipe from Methuen to Beverly, MA where it will interconnect with Algonquin's Hubline project (29 mi of 24" pipe)	Completed November 2003 230 mmcf/d (M&N); 300 mmcfd (Hubline)
2004	Everett Alternative	Algonquin Gas Transmission (Duke Energy)	Modification of compression facilities, primarily at Burrilville, RI station	Completed October 2004; 6 mmcfd
2005	Islander East	Algonquin Gas Trans (Duke Energy); Keyspan	Approx 50 miles of 24" pipe, extending from Algonquin in CT, across Long Island Sound to Wading River, NY	September 2005; 285 mmcf/d
	Tewkesbury Lateral	Tennessee Gas Pipeline (El Paso Energy)	Approx 5 miles of 8" pipe from Concord Lateral in Middlesex County, MA to new delivery point in Essex County, MA	FERC approved January 2005, 25 mmcfd
2007/08	Northeast ConneXion	Tennessee Gas Pipeline (El Paso Energy)	Incremental looping and compression on Line 200	open season conducted Oct Dec 2004; 100 mmcfd into New England; Nov 2007