Exhibit No. ___(JJR-1)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Maritimes & Northeast Pipeline, L.L.C.	§	Docket No. RP04-___-000
	§	

PREPARED DIRECT TESTIMONY
OF
JOHN J. REED
ON BEHALF OF
MARITIMES & NORTHEAST PIPELINE, L.L.C.

Q. 1 Please state your name and business address.

A. My name is John J. Reed. My business address is 313 Boston Post Road West, Suite 210, Marlborough, Massachusetts 01752.

Q. 2 By whom and in what capacity are you employed?

A. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("CEA"). CEA is a management consulting firm specializing in financial and economic services to the energy industry.

Q. 3 Please describe your professional background and experience.

A. I have more than twenty-five years of experience in the North American energy industry. Prior to my current position with CEA, I served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company. I have provided expert testimony on financial and economic matters on more than 125 occasions, including numerous proceedings regarding natural gas pipeline related matters, before the Federal Energy Regulatory Commission ("FERC"), various Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. A copy of my résumé and listing of the testimony I have sponsored previously is included as Exhibit No. __ (JJR-2).

Q. 4 On whose behalf are you sponsoring testimony in this proceeding?

A. I am sponsoring testimony on behalf of Maritimes & Northeast Pipeline, L.L.C. ("Maritimes").

Q. 5 What is the purpose of your testimony?

A. The purpose of my testimony is two-fold. In Section I, I introduce general information regarding the New England power market and the service problems faced by the New England pipeline grid. I also discuss the numerous direct and indirect benefits that the Maritimes Phase III facilities have brought to Maritimes' existing shippers. My testimony will illustrate how the Phase III project is consistent with the FERC's criteria for granting rolled-in rate treatment and, as a consequence, how rolled-in rate treatment is consistent with fulfilling the nation's energy needs. My testimony illustrates how the costs associated with the Phase III project, which was certificated and built in order to enhance service to Maritimes' existing customers, readily qualify for rolled-in treatment under the FERC's criteria. My testimony concludes that rolled-in rate treatment for costs associated with the Phase III facilities is appropriate under the 1999 Policy Statement.[1] Furthermore, I conclude that rolling in the costs associated with facilities such as the Phase III extension also encourages investment in critical energy infrastructure that is needed to overcome constrained natural gas service in New England.

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[1] Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227, order clarifying same, 90 FERC ¶ 61,128 (2000)("1999 Policy Statement").

Section II of my testimony provides factual information and professional judgments concerning the nature of the Atlantic Canada natural gas market and the effect of that market on the usage of Maritimes' system. My testimony in this regard supports the adjustment made by Maritimes to system throughput levels as those levels were measured during the base period for Maritimes' rate case (*i.e.*, the twelve (12) months ended February 29, 2004). Section II of my testimony supports a number of the evidentiary showings made by Maritimes in this rate case, including the manner in which throughput levels have been adjusted, as well as the testimony on billing determinants provided by Mr. William C. Penney, Jr. (Exhibit No. __ (WCP-1)). Based on the expected growth in demand for natural gas supplies in Canada and the implications that such demand has for natural gas supplied to New England markets via Maritimes & Northeast Pipeline Limited Partnership ("Maritimes-Canada"), I conclude that it is reasonable to expect that the gas available to the Northeast natural gas markets from Maritimes will be reduced during the test period, which ends November 30, 2004, and beyond. In light of this expected decline in imports, I conclude in Section II that the downward adjustment made by Maritimes to the test period's throughput levels is appropriate.

Q. 6 Are you sponsoring any statements, schedules or exhibits in conjunction with your direct testimony?

A. Yes. I am sponsoring the following exhibits: (i) Summary of Education and Qualifications (Exhibit No. ___(JJR-2), (ii) Average Annual Price Differentials (Exhibit No. ___(JJR-3)), (iii) Phase III Value Creation Since In-Service Date

(Exhibit No. ___(JJR-4)), and (iv) Phase III Value Creation, Projected for First Year of Operation (Exhibit No. ___(JJR-5)).

Section I- Shipper Benefits From Phase III Support Roll-In of Costs

New England Natural Gas Infrastructure is Constrained

Q. 7 Please provide an overview of the New England natural gas infrastructure.

A. The natural gas supply infrastructure serving demand in New England consists of interstate natural gas pipelines, underground natural gas storage facilities, liquefied natural gas ("LNG") facilities (including a marine import terminal, and storage facilities with and without liquefaction capability) and propane air facilities.

There are currently five interstate natural gas pipelines that deliver to New England: (i) Algonquin Gas Transmission Company ("Algonquin"); (ii) Tennessee Gas Pipeline Company ("Tennessee"); (iii) Iroquois Gas Transmission System, L.P. ("Iroquois"); (iv) Maritimes; and (v) Portland Natural Gas Transmission System ("PNGTS"). In addition to their independently owned systems, Maritimes and PNGTS also jointly own the primary pipeline facilities from where their two systems interconnect in Westbrook, Maine, to Dracut, Massachusetts. The jointly-owned pipeline facilities are known as the "Joint Facilities." Together, these five interstate pipelines provide natural gas supplies from four primary supply basins: Western Canada, Eastern Canada (Sable Island), the U.S. Mid-continent and the U.S. Gulf Coast.

In addition to the interstate pipelines, New England is served by storage fields in the Pennsylvania and New York areas, by LNG storage facilities in the New England region, and by Distrigas of Massachusetts LLC ("DOMAC"). DOMAC is a large LNG facility located in Everett, Massachusetts. DOMAC is the only facility in New England that operates an import receiving terminal for marine shipments of international LNG supplies. Finally, there are several small propane facilities throughout the region.

Q. 8 Does the New England natural gas infrastructure currently provide sufficient supply to meet the region's demand?

A. Yes. However, while there is sufficient gas supplied to the region to meet the current demand, the infrastructure is insufficient to move the gas freely from the market area delivery points of the pipelines to the load centers. The physical infrastructure limitations create bottlenecks across the system, leading to sustained price differentials on different pipeline systems serving the same market. For example, historically the Algonquin market area has been a tight supply area while Dracut and Tennessee Zone 6 can be a supply bottleneck, which are demonstrated by the pricing differentials in these submarkets.

The Phase III Facilities Provide Significant Benefits to Existing Maritimes Shippers

Q. 9 Please describe the Phase III facilities.

A. The Phase III facilities represent an extension of Maritimes' mainline facilities from Methuen, Massachusetts, to an interconnection in Beverly, Massachusetts, with Algonquin.

Q. 10 What benefits to Maritimes' existing customers did the Commission note in its Preliminary Determinations on Non-Environmental Issues regarding Maritimes' Phase III certificate application?[2]

A. The Commission specifically identified that the Phase III Project will provide Maritimes' existing customers with the following benefits: (i) access to existing natural gas markets on the eastern end of Algonquin's system, notably including the Boston market, (ii) access to proposed markets, (iii) access to another downstream pipeline alternative, (iv) greater opportunities to maximize the use of their capacity, and (v) reduced scheduling and curtailment risks associated with using multiple downstream pipelines.

Q. 11 Please explain how Phase III enhances existing customers' ability to reach existing New England markets for their natural gas.

A. The Phase III extension integrates four of the interstate pipelines that serve New England; Maritimes, PNGTS (through the Joint Facilities), Tennessee and Algonquin. As is further explained by Mr. Penney and Mr. Richard J. Kruse in their testimony, the Maritimes pipeline receives essentially all of its supplies from the Sable Offshore Energy Project ("SOEP") in Goldboro, Nova Scotia. The Maritimes pipeline has the ability to receive additional supplies from PNGTS at Westbrook, Maine, and can receive gas by displacement at most other interconnections on the system. Prior to the development of the Phase III facilities, with the exception of deliveries to power plants located in Maine and New Hampshire, the predominant use of the Maritimes pipeline was to transport gas supplies to Dracut, Massachusetts. At the Dracut delivery point, the only take-away capacity available to transport supplies to end-use markets is

[2] *Maritimes & Northeast Pipeline, L.L.C.*, Preliminary Determinations on Non-Environmental Issues ("Preliminary Determination"), 95 FERC ¶ 61,077 (2001).

Tennessee. The Phase III extension provides Maritimes' existing shippers an alternative to Tennessee to reach downstream markets through the Phase III extension's interconnection with the Algonquin system.

Q. 12 Please explain the benefits to existing shippers of having access to the Greater Boston market through Phase III.

A. Prior to Phase III, the only way to access the Greater Boston market was through the Tennessee system. The addition of Phase III allows shippers direct access to the Greater Boston market. In the Phase III certificate proceeding, the FERC observed that direct access to Algonquin's system would permit Maritimes' shippers to have another pipeline alternative to reach gas markets and allow its shippers to avoid the additional costs of transporting gas on Tennessee as well as additional scheduling and curtailment risks inherent in using multiple downstream transporters.[3]

Q. 13 You indicated earlier that the New England pipeline grid has operational constraints that create market inefficiencies. Does Phase III help to relieve any of these constraints?

A. Yes. By further integrating the New England pipeline grid, the Phase III facilities allow gas supplies of existing shippers to more easily flow to the highest value market. As I have discussed previously, the New England pipeline grid has physical flow limitations that have created pricing differentials across the region, reflecting the supply-demand imbalances. For example, as is illustrated in Exhibit No. ___ (JJR-3), in the two years prior to the Phase III extension (2002 and 2003), daily gas prices at Dracut averaged $0.24 per dekatherm ("Dth") less than prices

[3] Preliminary Determination, 95 FERC ¶ 61,077, at p. 61,227.

at Algonquin city gates in the Boston area, and prices at Dracut averaged $0.14/Dth less than prices for the rest of Tennessee's New England deliveries.

The ability to access higher-value markets is a direct financial benefit to existing shippers. The fact that the Phase III facilities are being well used by Maritimes' shippers, as Mr. Penney notes in his testimony, demonstrates that these facilities have improved the efficiency of the market, and that existing customers are enjoying the benefit of these higher-value markets.

Q. 14 You stated previously that access to higher-value markets, through the Phase III facilities has provided existing customers with direct financial benefits. Have you conducted an analysis to determine the potential incremental value to existing shippers of accessing alternate markets?

A. Yes. I have analyzed the potential value that accrues to Maritimes' existing shippers of having the option to deliver to either Tennessee at Dracut or Algonquin at Beverly. The results of this analysis are presented in Exhibit No. ___ (JJR-4).

Q. 15 Please explain the methodology and assumptions used to develop your estimate of potential value.

A. In my analysis, I calculated two potential values for Maritimes' existing shippers' supplies in the New England marketplace for the period beginning on November 24, 2003, the in-service date for Phase III, through March 31, 2004.

First, I calculated the potential value that would have been achieved by existing shippers if Phase III were not available as an alternative. In my calculation, I assume that the volume that Maritimes' shippers can move to either Beverly or Dracut is 300,000 Dth per day ("Dth/d"), which currently is the approximate takeaway capacity on Algonquin's facilities at Beverly. In this calculation, I assume that the entire 300,000 Dth/d is delivered to Dracut, Massachusetts, during the winter period and all volumes were sold at the average daily price at the Dracut delivery point, as reported in Gas Daily. The total value under this calculation is simply the sum of the daily prices multiplied by the sum of the daily delivery quantities assumed.

Next, I calculated the potential value to existing shippers resulting from the ability to choose between delivering to Dracut and delivering supplies to Algonquin in Beverly through the Phase III facilities. In this calculation, I assume that shippers will determine where they nominate based on the average daily market prices as reported by Gas Daily for Dracut and the Algonquin city gate. I assume that a shipper will nominate its full Maximum Daily Transportation Quantity ("MDTQ") to the higher-value market. Total value is then calculated as the sum of the higher daily market prices multiplied by the sum of the daily delivery quantities assumed.

Finally, I calculate the potential value associated with the Phase III facilities. The potential value of Phase III is the difference between the value that would be achieved if existing shippers delivered only to Dracut and the value achieved if existing shippers elect to deliver to the higher priced market on each individual day.

Q. 16 Based on this analysis, what do you conclude is the benefit to existing shippers of access to higher value markets through the Phase III facilities?

A. For the four-plus months from the in-service date of the Phase III facilities, November 24, 2003, through March 31, 2004, the potential value created for existing shippers by the addition of the Phase III facilities to the Maritimes system was approximately $23 million, as shown in Exhibit ___ (JJR-4). If gas prices for

April 1, 2004, to November 23, 2004, matched the levels for the same period in the prior year, the total potential value created by the Phase III facilities in their first year of operation would be $41.2 million, as shown in Exhibit ___ (JJR-5). This value excludes the reliability, flexibility and capacity utilization benefits that existing shippers also receive.

Q. 17 Did shippers actually achieve this value?

A. To the extent that a shipper made its determination on whether to deliver into Tennessee at Dracut or into Algonquin at Beverly due to the basis differential between the two points, that shipper would have achieved this value.

Q. 18 Please identify the new market areas that are accessible to Maritimes' existing customers as a result of the Phase III facilities.

A. As identified by the FERC, Phase III provides Maritimes' existing customers direct access to new and existing markets on the Algonquin system:

> [T]he Phase III Project's direct access to proposed markets, such as the Sithe [Exelon] and Southern [Mirant] electric generation facilities, and to existing markets on Algonquin's system will provide current shippers with a greater opportunity to maximize use of their capacity on Maritimes.[4]

As noted by Mr. Ditzel, in addition to potential markets that may be developed that are adjacent to the pipeline route, by backfeeding the Algonquin system, the Phase III facilities strengthen all deliveries to Southeastern Massachusetts and Rhode Island.

[4] Preliminary Determination, 95 FERC at p. 61,227.

Q. 19 What other benefits accrue to Maritimes' existing customers with the addition of Phase III to the Maritimes system?

A. In addition to the increased netbacks discussed earlier from the connection to Algonquin, the addition of Phase III provides existing customers with increased reliability of services, system flexibility and incremental market-area capacity that allows them to maximize the use of their capacity.

Q. 20 Please explain how the Phase III facilities have increased the reliability of service for existing shippers.

A. The Phase III extension increases reliability on Maritimes, PNGTS, Tennessee and Algonquin by de-bottlenecking two key constraint points on the New England pipeline grid. The first point is the Dracut interconnect between the Joint Facilities and Tennessee, and the second point is the Greater Boston-area terminus of the Algonquin system.

By providing an additional outlet for volumes off the Joint Facilities, the Phase III extension has reduced the volumes flowing to Dracut, thereby reducing or eliminating constraints on Tennessee's ability to take volumes away from Dracut and providing existing shippers an alternate route if Tennessee's system were down for repairs, maintenance or an emergency, as discussed by Mr. Christopher T. Ditzel in his testimony.

Q. 21 Can the reliability benefits discussed above be quantified?

A. While the value of increased reliability is difficult to quantify, reliability of the system is critical for Maritimes' shippers. The majority of Maritimes' shippers are affiliates of SOEP producers that have access to only one outlet to bring supplies to market, the Maritimes pipeline. Since it is extremely difficult to regulate production from the offshore platforms, it is critical that the Maritimes pipeline provide shippers with reliable service. In the event that service on the Maritimes system were interrupted for an extended period of time, or during a peak-production period, SOEP production would not have an outlet, leaving only one very costly alternative for producers: shutting in production until Maritimes service was restored.

Q. 22 Please explain the operational flexibility benefits of the Phase III facilities for existing Maritimes shippers.

A. As Mr. Ditzel explains in his testimony, by providing an additional interconnect among Maritimes, PNGTS, Tennessee and Algonquin, the Phase III facilities provide existing shippers with greater operational flexibility between the pipelines that serve the region. Maritimes' existing shippers also benefit generally from the increase in the reliability of the New England pipeline grid created by the Phase III facilities.

Q. 23 You indicated previously that Phase III provides existing Maritimes shippers the opportunity to maximize the use of their capacity. Please explain.

A. The capacity that existing shippers hold on Maritimes becomes more useful and hence more valuable as a result of the existence of the Phase III facilities. Even when firm shippers choose to continue to deliver gas to Dracut, they have the opportunity to release their firm entitlements on Phase III from Methuen to Beverly, allowing a replacement shipper to access the Algonquin market directly. Alternatively, as Mr. Penney explains in his testimony, an existing shipper can segment the Methuen to Beverly section of the system to deliver additional supplies from PNGTS to Algonquin even when it is delivering its full MDTQ at Dracut. As such, firm capacity holders have the opportunity to access two markets on a daily basis with their full MDTQ, either by delivering to both of these markets or by segmenting the capacity and releasing it to a third party.

__The Phase III Facilities Address FERC and Market Issues with the New England Pipeline Grid__

Q. 24 Please identify the benefits that are provided to the New England pipeline grid by construction of Phase III.

A. The construction of Phase III has provided several benefits to the existing Maritimes' shippers and to the New England pipeline grid. These benefits include: 1) increased reliability of service to the regional power markets, 2) increased ability to serve new electric generation, and 3) increased flexibility and reliability to the New England pipeline grid.

Q. 25 How do regional power markets benefit from Phase III?

A. Phase III provides two main benefits to the regional power markets: (i) increased flexibility of the pipeline grid, and (ii) the ability to serve new gas-fired generation.

The independent system operator for New England ("ISO-NE")[5] has raised concerns for several years regarding the ability of the New England pipeline grid to serve the increasing demand of the power markets, potentially threatening the reliability of the power grid. By increasing the flexibility of the New England pipeline system, Phase III makes it possible to provide more reliable gas transportation service to electric generation across the region.

[5] ISO-NE is the not for profit corporation responsible for the day to day operation of New England's bulk power generation and transmission system; oversight and administration of the region's wholesale electricity marketplace; and management of a comprehensive regional bulk power system planning process. *See* ISO-NE homepage, available at: <http://www.iso-ne.com>.

In addition, Phase III provides the ability to serve new generation with firm transportation service offerings. For example, the Phase III facilities have made it possible for Maritimes' shippers to directly serve the new 800 MW Fore River Generating Station in Weymouth, Massachusetts. The addition of the Fore River facility to the power grid increases the reliability of the power grid in a previously constrained region.

Q. 26 Have there been any studies performed to examine the adequacy of the New England natural gas infrastructure?

A. Yes. In December 2003, in compliance with The Pipeline Safety Improvement Act of 2002, the FERC, in consultation with the Department of Energy, completed a study of the natural gas pipeline system and storage in New England.

Q. 27 Briefly, what did FERC conclude?

A. The FERC staff concluded that while the New England natural gas market has adequate capacity to meet its short-term projected firm demand, the natural gas infrastructure in New England is tight and has limited ability to withstand or respond to disruptions:

> The New England natural gas pipeline system is fully loaded December through February, and projected increases in capacity are expected to be completed just-in-time to meet new capacity demands. There is little opportunity for this system to rely on excess capacity as a buffer against curtailment. Should the unexpected occur, a localized curtailment of service is the likely outcome.[6]

Q. 28 Did FERC staff make any recommendations?

A. Yes. The staff report provides short-term and long-term recommendations to enhance the pipeline grid and the New England supply of natural gas. In the long

[6] "Staff Report of the Federal Energy Regulatory Commission-- New England Natural Gas Infrastructure," Docket No. PL04-1, at 23 (December 13, 2003).

term, the staff recommended the development of additional natural gas pipeline capacity to access new natural gas supplies or new LNG facilities. In the short term, the staff recommended additional integration of the existing pipeline system to increase reliability.

Q. 29 What input did FERC receive for the study?

A. The FERC contacted the state public utility commissions, the New England Conference of Public Utility Commissions, ISO-NE, and the Northeast Gas Association ("NGA") to solicit input on the study. The FERC used input received from these sources, additional parties, and FERC staff primary research to develop its analysis of the New England natural gas infrastructure.[7]

The analysis reviewed the current and proposed pipeline infrastructure, as well as New England market demand for natural gas, to determine the adequacy of the pipeline infrastructure to meet the short and long term natural gas demand in the New England region.

Q. 30 Did the FERC receive comments in response to its solicitation?

A. Yes. The FERC received comments from the NGA, ISO-NE and other market participants.

Q. 31 What was the NGA's assessment of the New England natural gas infrastructure?

A. The NGA stated that the New England natural gas system requires continued infrastructure additions to meet increasing market demand, most notably the increasing demand of the power generation sector. In addition, the NGA

[7] "Staff Report of the Federal Energy Regulatory Commission-- New England Natural Gas Infrastructure," Docket No. PL04-1 (December 13, 2003).

indicated that the infrastructure additions are necessary to increase the availability of gas supply, as well as to support system flexibility and reliability.

Q. 32 Did the NGA provide recommendations as to specific system enhancements that would achieve these goals?

A. Yes. The NGA acknowledged that there were several projects that were proposed and under construction at that time that would help to support system flexibility and increase system reliability and included a list of these projects in its correspondence to the FERC. The NGA stated:

> Over the last several years, recognizing the need for new infrastructure to meet market demand, the FERC issued approvals for several gas pipeline projects in New England and New York. Three of these are currently under construction and are scheduled to come into operation within the next several months.
>
> Additional new infrastructure projects are planned for the region for the 2004-2010 timeframe. These projects will help further increase regional natural gas capacity, deliverability, flexibility and reliability, as well as provide economic benefits to the region. [8]

Q. 33 Did the NGA indicate that Phase III provided these benefits?

A. Yes. The list of projects identified by the NGA as helping to support system flexibility and increase system reliability included the Phase III project.

Q. 34 What was ISO-NE's assessment of the New England pipeline infrastructure?

A. ISO-NE indicated that deliverability of competitively-priced natural gas to generation facilities is a concern for the region. ISO-NE stated that "New England's comparative remoteness from gas producing basins has resulted in less flexible physical ties to the major producing and storage areas serving the

[8] Letter from Thomas Kiley, President of Natural Gas Association to Mark Robinson, Director of the Office of Energy Projects, Federal Energy Regulatory Commission, August 29, 2003, at 4.

region."[9] Furthermore, ISO-NE stated its concern that due to the limited flexibility of the New England pipeline grid, it is possible that the pipeline grid would not be able to accommodate the demand of gas utilities and merchant generators during the coldest period of the winter.

Q. 35 Did ISO-NE provide any recommendations to resolve this issue?

A. Yes. ISO-NE supported the development of increased flexibility for the system and indicated that increased interconnection between the pipelines serving the region has helped develop this flexibility. "In the last several years, improvements to the ties south of New England, in particular realization of bi-directional supplies in the upstream portions of these ties, has created valuable operating flexibility across all New England pipelines and, thus, has improved the security of gas deliveries."[10]

Q. 36 How do the Phase III facilities address the issues identified by the FERC, the NGA and ISO-NE?

A. The FERC, the NGA, and ISO-NE all recognize that in the short term, integration of the pipeline grid is critical to ensure the reliability of delivery capability for the region. By integrating Tennessee, PNGTS, Algonquin and Maritimes, the Phase III facilities help to provide the additional integration of the existing pipeline system and the additional operational flexibility that has been identified as critical to the short-term reliability of the New England pipeline system. By allowing the eastern end of the grid to be served directly by Maritimes, West to East supplies can be delivered to upstream markets, creating more reliability in those markets.

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[9] Letter from Stephen Whitley, ISO-New England to J. Mark Robinson, Director of the Office of Energy Projects, Federal Energy Regulatory Commission, August 14, 2003 at 2.
[10] *Id*.

Q. 37 How do the Phase III facilities address the concerns of ISO-NE with regard to deliverability of supplies to new merchant generation?

A. The Phase III facilities provide Maritimes' shippers direct service to 800 MW of incremental electric generation at Fore River Generating Station in Weymouth, Massachusetts.

Phase III Costs Qualify For Rolled-In Rate Treatment; Rolled-In Rate Treatment Provides Appropriate Market Price Signals.

Q. 38 Please provide an overview of the FERC's policy with regard to rate treatment of new pipeline extension/expansion facilities.

A. The FERC established its current ratemaking policies for pipeline expansion/extensions in its Certification of New Interstate Natural Gas Pipeline Facilities ("1999 Policy Statement").[11] The 1999 Policy Statement is intended to provide guidance as to how the Commission will evaluate proposals for certificating the construction of new pipeline facilities.

In addition to outlining the FERC's criteria for certificating new pipeline facilities, the 1999 Policy Statement outlines the FERC's intentions with respect to rate treatment for pipeline extension and expansion facilities. In the 1999 Policy Statement, the FERC established its threshold requirement for existing pipelines proposing an expansion or extension project: the project must be able to proceed without subsidies from the pipeline's existing customers. The 1999 Policy Statement further states a presumption of incremental rates in such cases where rolling in the costs of new facilities would result in a subsidy from existing customers.

[11] 1999 Policy Statement, 88 FERC ¶ 61,227 (1999).

While the 1999 Policy Statement clearly presents the FERC's "no subsidies" requirement, it also clearly states that rolled-in rates do not create a subsidy when expansion/extension facilities provide benefits to existing customers:

> Projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility, are for the benefit of existing customers. Increasing the rates of the existing customers to pay for these improvements is not a subsidy. Under current policy these kinds of projects are permitted to be rolled in and are not covered by the presumption of the current [incremental] pricing policy.[12]

Q. 39 Do the Phase III facilities meet the criteria identified by the FERC for rolled-in rate treatment?

A. Yes. While the Phase III facilities have created many market benefits, as was recognized by the FERC in the Preliminary Determination for Phase III, [13] the project was designed with the intention of improving service to existing customers and providing direct access to the Greater Boston market. The benefits of Phase III for existing Maritimes customers, including greater access to new and existing markets, additional operational flexibility and reliability, increased netbacks, and access to higher value markets, have been discussed previously in significant detail in my testimony and in Maritimes' Phase III certificate application.

Q. 40 Has the FERC acknowledged the benefits to existing shippers from the Phase III facilities?

A. Yes. Not only did the FERC acknowledge those benefits in the Preliminary Determination for the Phase III extension, it made those benefits the primary basis

[12] 1999 Policy Statement, 88 FERC at p. 61,746 n. 12.
[13] Preliminary Determination, 95 FERC ¶ 61,077.

of its conclusion that the project was required for the public convenience and necessity. The Commission noted that Maritimes' proposal did not add new load, "but merely enhances its existing service to its existing customers."[14]

Q. 41 Do all existing shippers receive the benefits of the Phase III facilities?

A. Yes. All existing firm shippers have the contractual right to use the Phase III facilities, including the Beverly delivery point as an alternate primary delivery point, for up to their full MDTQ.

Q. 42 Have all existing firm shippers indicated an intention to use the Phase III facilities?

A. Yes. As Mr. Penney testifies, prior to the in-service date, Maritimes provided the existing long-term firm shippers the option to specify the new Algonquin delivery point as an additional primary delivery point for up to their full MDTQ. All existing long-term firm shippers elected this option, and Maritimes amended the contracts for all of the existing long-term firm shippers to include the Algonquin delivery point as an additional primary delivery point for their full MDTQ.

Q. 43 Since the Phase III facilities have been operating, have the existing shippers utilized the extension?

A. Yes. As stated by Mr. Penney in his testimony, gas has flowed to the Algonquin delivery point on a primary firm basis or through capacity release under each of the existing long-term firm service agreements. Existing shippers have used the extension to deliver their own supplies and have released capacity on this segment of the pipeline to third parties. During the period from December 1, 2003,

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[14] Preliminary Determination, 95 FERC ¶ 61,077, at p. 61,228.

through April 30, 2004, the Algonquin delivery point on Maritimes has received 12,548,239 Dth, or 82,554 Dth/d on average.

Section II - Canadian Demand Supports Throughput Adjustment

Q. 44 What is the purpose of this section of your testimony?

A. In this section I address the growth of the market for natural gas in Atlantic Canada,[15] and I assess the implications of that growth for natural gas supplied to New England markets via the Maritimes pipeline. As of December 1, 1999, the in-service date of the Maritimes system, Maritimes had 195,000 Dth/d in firm contracts for delivery in Canada. Canadian customers have consistently taken far less than that quantity due to various delays in the development of that market and price arbitrage opportunities in U.S. markets. However, as Mr. Kruse notes in his testimony, demand levels for natural gas supplies in Canada have started to increase towards levels originally anticipated, and thus, considering that production from Maritimes' primary supply source is decreasing, as Mr. Kruse explains, gas supplies flowing to the Northeast natural gas markets from Maritimes will be reduced from base period levels. Consequently, I conclude that the downward adjustment made by Maritimes to its base period throughput levels is reasonable.

Q. 45 Please provide an overview of the market for natural gas in Atlantic Canada.

A. The distribution of natural gas has only recently been introduced to Atlantic Canada, beginning with the commencement of service of the Maritimes-Canada

[15] Atlantic Canada is defined as Nova Scotia and New Brunswick, Canada for the purposes of this testimony.

pipeline in late 1999. In mid 2000, large industrial customers and electric generation customers began contracting for capacity on the Maritimes-Canada system. Today, these customers have contracted for in excess of 94 percent of the 195,000 Dth of capacity that has been contracted to serve the Atlantic Canadian market for natural gas. Contemporaneously with the completion of the Maritimes-Canada pipeline, distribution franchises were awarded in both New Brunswick and Nova Scotia. The capacity commitments of distribution companies represent the remaining 6 percent of the Atlantic Canadian capacity on Maritimes- Canada.

Q. 46 How did the market respond to natural gas as an alternative energy source?

A. As referenced earlier, the natural gas markets in New Brunswick and Nova Scotia experienced some false starts. In New Brunswick, the government redesigned the market to allow the LDC to offer bundled supply service to customers to stimulate market activity.[16] In Nova Scotia, the government was required to award a new franchise after the initial franchise holder abandoned its franchise.[17] Through October 2000, there was no market for natural gas in New Brunswick and Nova Scotia.

Q. 47 Since October 2000, how has the market responded?

A. Since that time, demand for natural gas in these Provinces has increased, as was initially anticipated. As Mr. Penney discusses in his testimony, currently, the

[16] The Gas Distribution Act required that the LDC be only a distributor of natural gas. This structure required the LDC to rely on natural gas marketers to develop the market for natural gas in the province, and those marketers were also selling fuel oil and propane to customers. Due to the problems associated with that model, the Gas Distribution Act was amended in March 2003 to allow the LDC to purchase and sell natural gas directly to customers.

[17] Sempra was awarded the initial distribution franchise for Nova Scotia, but abandoned the franchise in 2001.

combined average daily deliveries for New Brunswick and Nova Scotia are approximately 65,000 Dth/d. However, the currently contracted firm transportation on Maritimes-Canada with Canadian primary delivery points is 195,000 Dth/d. As illustrated by Mr. Penney in his testimony, this capacity is largely subscribed by large industrial and electric generation users. While the average daily deliveries are approximately 65,000 Dth/day, the fact that large customers have contracted for significantly more capacity indicates the growth in Canadian deliveries that Canadian shippers expect.

Q. 48 Is there evidence to suggest that demand for natural gas in Atlantic Canada will continue to increase over time?

A. Yes. The commitment to developing a viable market for natural gas in Atlantic Canada has been widespread. Again, the governments of New Brunswick and Nova Scotia have enacted policies and awarded franchises to promote the development of the natural gas industry. Electric generators have indicated their intentions to increase use of natural gas and have made investments that facilitate increased natural gas consumption. In addition, the LDCs have made long-term commitments to build the infrastructure that is necessary to provide access to natural gas to residential, commercial and industrial end-users. Currently, the LDCs and governments in Atlantic Canada are working together to implement marketing and pricing plans designed to attract existing customers to natural gas as a primary fuel source.

Q. 49 Have generators already planned investments in new gas-fired generation in Atlantic Canada?

A. Yes. Nova Scotia Power applied for and was granted approval to purchase and install a $34.5 million, 50 MW gas-fired turbine at the Tufts Cove facility. Unlike the existing turbine at the Tufts Cove facility, which can switch fuels based on economics, this turbine will burn natural gas exclusively. The new turbine is expected to come on-line by the 2004/2005 winter season.

Q. 50 Are there other natural gas-fired generation projects planned for the Maritimes region?

A. Yes. TransCanada Energy Ltd. ("TCE") has planned an $85 million, 90 MW heating and electric co-generation project to be located at the Irving Oil refinery in New Brunswick. In January 2004, TCE received a single end-use franchise from the New Brunswick Board of Public Utilities to buy natural gas to fuel this project. The Irving Oil facility will be relying on its contracted capacity on the Maritimes-Canada pipeline to transport the natural gas to fuel this project. The project is currently under construction and is expected to be completed by the end of 2004.[18]

Q. 51 Are there other influences on the demand for gas in Atlantic Canada?

A. Yes. The demand for natural gas in the U.S. influences the consumption of natural gas in Canada. Canadian and U.S. markets are economically integrated. As such, as demand increases in the U.S. and the spread between the value of gas in the U.S. and Atlantic Canada widens, increased supplies of natural gas flow to the U.S. during peak periods.

Q. 52 What is the effect of this price arbitrage on the Northeast market?

A. In the example described above, where the value of natural gas is significantly higher in U.S. markets than in Canadian markets, deliveries from Maritimes-Canada to U.S. markets increased, as many Canadian natural gas consumers took

[18] Khalid Malik, "Natural Gas franchise approved for Oil refinery power plant", New Brunswick Telegraph-Journal, January 7, 2004.

advantage of the arbitrage opportunities by diverting gas purchased for Canadian consumption, on an interruptible basis, to the higher-priced U.S. markets. This increase in deliveries to U.S. markets, which was driven by economics, resulted in an increase in the average daily throughput on the U.S. segment of the pipeline. Such significant price differentials are however, temporary phenomena that cannot be predicted or expected.

Q. 53 Assuming the absence of arbitrage opportunities, what is the likely near-term outcome of the above-described marketing and development activities on Atlantic Canadian consumption of natural gas?

A. Consumption in the Atlantic Canadian markets will continue to increase as a result of these efforts. In the aggregate, Atlantic Canadian consumers have contracted for 195,000 Dth/d of long term firm capacity on Maritimes-Canada with primary delivery points in Atlantic Canada. These contracts were established in order to meet the demand of Canadian consumers. As is discussed by Mr. Penney, Canadian consumption of natural gas is 65,000 Dth/d, with limited demand from the LDCs and a significant amount of gas diverted to U.S. markets to take advantage of price arbitrage opportunities. As the markets equilibrate and arbitrage opportunities between the U.S. and Canadian markets dissipate, the risk of Canadian demand decreasing is minimal. It is much more likely that Canadian demand will increase than decrease.

Increasing Demand for Natural Gas in Canada will Reduce the Imports to the Northeast Natural Gas Markets From Maritimes.

Q. 54 What options exist for natural gas supply to the Atlantic Canada?

A. At the present time, the Atlantic Canada natural gas market is supplied almost exclusively by Maritimes-Canada, which transports natural gas sourced essentially just from the SOEP.[19]

Q. 55 Does Atlantic Canada have access to storage or LNG facilities to meet market demand?

A. No, not at this time.

Q. 56 How will future Atlantic Canadian demand affect the Northeast natural gas markets?

A. The Maritimes-Canada system is currently designed with one point of injection, at Goldboro, Nova Scotia. Therefore, as Atlantic Canadian demand increases, the Maritimes pipeline will have less supply to deliver to the Northeast U.S. markets.

Q. 57 What does this increased demand in Canada suggest for the billing determinants used to establish rates on the Maritimes pipeline?

A. The billing determinants on the Maritimes pipeline should be adjusted downward from base period levels to reflect expected usage. Based on the market developments described above, the reduction to base period billing determinants proposed by Mr. Penney in his testimony is appropriate. Mr. Penney, in fact, has only adjusted throughput for expected reductions in SOEP production. He has only assumed that Canadian consumption will remain the same during the test period as it was during the base period. I think this is a conservative view. In my view, Canadian consumption will stay the same or increase during the test period.

<u>Conclusions</u>

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[19] Atlantic Canada has a very limited amount of local production.

Q.58 Please summarize why rolled-in treatment is appropriate for the costs of the Phase III extension.

A. As the FERC has already noted, the Phase III facilities provide significant benefits to existing shippers. These benefits warrant rolled-in rate treatment for the Phase III facilities. For Maritimes shippers, the Phase III facilities provide:

- Access to higher-value markets on Algonquin; based on recent price differentials, this access has created the potential of up to $41million in annual benefits for existing Maritimes shippers.
- A more competitive market at Dracut, resulting in higher net backs for shippers;
- Increased reliability and flexibility for shippers on the Maritimes system as a whole; and
- Separate, releasable entitlements on both the Dracut and Beverly market legs, which increases the value of the shippers' mainline capacity.

Q.59 Please summarize why you have concluded that it is reasonable to make a downward adjustment to the throughput levels as measured over the base period.

A. Based on the current demand for natural gas in Canada as compared with the contracted capacity to serve the Canadian market, it is reasonable to conclude that the risks associated with Canadian demand levels are asymmetric. It is much more likely that Canadian demand will increase than decrease. Given the expected growth in demand for natural gas supplies in Canada and the implications that such demand has for natural gas supplied to New England markets via Maritimes-Canada, the volumes likely to flow to the Northeast U.S. natural gas markets via Maritimes will be reduced. Notwithstanding this likelihood, Mr. Penney has only adjusted throughput for expected reductions in SOEP production. Mr. Penney has not assumed any increase in Canadian consumption of SOEP supplies, which I find to be conservative. Thus, in my view, the throughput levels assumed by Mr. Penney for purposes of establishing Maritimes' billing determinants is certainly justified.

Q.60 Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maritimes & Northeast Pipeline, L.L.C.	§ § §	Docket No. RP04-

AFFIDAVIT OF JOHN J. REED

JOHN J. REED, being first duly sworn, on oath states that he is the witness whose Prepared Direct Testimony is filed herein; that, if asked the questions which appear in the text of aforesaid Prepared Direct Testimony, affiant would give the answers that are herein set forth; and that affiant adopts the aforesaid Prepared Direct Testimony as his sworn, direct testimony in this proceeding.

JOHN J. REED

SUBSCRIBED AND SWORN TO before me, a Notary Public in and for the Commonwealth of Massachusetts, County of Middlesex this 23rd day of June, 2004.

Notary Public

Christopher P. O'Keefe
My Commission Expires April 17, 2009

My commission expires: ______________________

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 125 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join CEA as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 20 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

Navigant Consulting, Inc. (1997- 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988-1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983-1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981-1983)
Senior Consultant
Consultant

Southern California Gas Company (1976-1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

BS, Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses.

BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Conn. Department of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Federal Energy Regulatory Commission				
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Rate Case Analysis Cost of Service
Colonial Gas, Providence Gas	7/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	8/93	Algonquin Gas Transmission	RP93-14 – Rebuttal	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Tennessee GSR Group	1/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Pacific Gas Transmission	2/95	Pacific Gas Transmission	RP94-149-000	Rate Design
Tennessee GSR Customer Group	3/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
ProGas and Texas Eastern	1/96	Tennessee Gas Pipeline Company	RP93-151	Declaration
PG&E and SoCal Gas	96	El Paso Natural Gas Company	RP92-18	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/2000	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/2000	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/2001	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection (Direct)
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
The Berkshire Gas Company	5/92	The Berkshire Gas Company	DPU #92-154	Gas Purchase Contract Approval
Essex County Gas Company	5/92	Essex County Gas Company	DPU #92-155	Gas Purchase Contract Approval
Fitchburg Gas and Elec. Light Co.	5/92	Fitchburg Gas and Elec. Light Co.	DPU #92-156	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company	11/93	The Berkshire Gas Company	DPU #93-187	Gas Purchase Contract Approval
Colonial Gas Company	11/93	Colonial Gas Company	DPU #93-188	Gas Purchase Contract Approval
Essex County Gas Company	11/93	Essex County Gas Company	DPU #93-189	Gas Purchase Contract Approval
Fitchburg Gas and Electric Company	11/93	Fitchburg Gas and Electric Company	DPU #93-190	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs – Direct
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Regulatory Issues
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
New Hampshire Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/2000	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/2001	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Tariff Changes
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Service - Direct
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices
Texas Railroad Commission				
Southern Union Gas	5/85	Southern Union Gas Company	G.U.D. 1891	Cost of Service
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/2000	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern	Arbitration Panel	Gas Contract Arbitration
Attala Generating Company	10/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/2000	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Ocean State Power	9/02	Ocean State Power v. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power v. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
State of Rhode Island, Providence City Court				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U.S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/2000	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation

Average Annual Price Differentials

	Average Monthly Prices			Average Monthly Price Differential		
	Algonquin	Dracut	Tenn Z6	Algonquin-Dracut	Algonquin-TZ6	TZ6-Dracut
Nov-01	$2.72	$2.45	$2.64	$0.27	$0.08	$0.18
Dec-01	$2.84	$2.53	$2.72	$0.31	$0.12	$0.19
Jan-02	$2.88	$2.42	$2.77	$0.46	$0.10	$0.36
Feb-02	$2.71	$2.49	$2.62	$0.22	$0.08	$0.14
Mar-02	$3.40	$3.21	$3.34	$0.19	$0.06	$0.13
Apr-02	$3.70	$3.50	$3.65	$0.20	$0.05	$0.15
May-02	$3.86	$3.70	$3.82	$0.16	$0.05	$0.11
Jun-02	$3.51	$3.32	$3.45	$0.19	$0.06	$0.13
Jul-02	$3.34	$3.12	$3.26	$0.22	$0.08	$0.14
Aug-02	$3.45	$3.24	$3.38	$0.21	$0.07	$0.14
Sep-02	$3.81	$3.62	$3.76	$0.19	$0.05	$0.14
Oct-02	$4.33	$4.40	$4.31	-$0.06	$0.03	-$0.09
Nov-02	$4.58	$4.46	$4.55	$0.11	$0.03	$0.08
Dec-02	$5.95	$5.63	$5.69	$0.32	$0.26	$0.06
Jan-03	$8.52	$8.17	$8.35	$0.35	$0.17	$0.17
Feb-03	$10.90	$10.36	$10.39	$0.55	$0.51	$0.04
Mar-03	$8.29	$8.08	$8.02	$0.21	$0.27	-$0.06
Apr-03	$5.97	$4.96	$5.85	$1.01	$0.12	$0.89
May-03	$6.18	$5.99	$6.11	$0.19	$0.07	$0.12
Jun-03	$6.23	$6.04	$6.15	$0.19	$0.08	$0.11
Jul-03	$5.46	$5.31	$5.40	$0.15	$0.07	$0.08
Aug-03	$5.43	$5.33	$5.40	$0.10	$0.03	$0.07
Sep-03	$4.81	$4.88	$4.97	-$0.07	-$0.16	$0.09
Oct-03	$5.16	$5.05	$5.17	$0.10	-$0.01	$0.11
Nov-03	$5.11	$4.93	$5.01	$0.18	$0.10	$0.08
Dec-03	$6.97	$6.62	$6.87	$0.35	$0.10	$0.25
Jan-04	$12.69	$11.04	$11.53	$1.64	$1.15	$0.49
Feb-04	$6.48	$6.21	$6.34	$0.27	$0.13	$0.13
Mar-04	$5.98	$5.81	$5.92	$0.17	$0.06	$0.11
2002	$3.79	$3.59	$3.72	$0.20	$0.08	$0.12
2003	$6.59	$6.31	$6.47	$0.28	$0.11	$0.16
2004 Q1	$8.38	$7.69	$7.93	$0.69	$0.45	$0.24
01-02 Winter	$2.96	$2.66	$2.87	$0.30	$0.09	$0.20
02-03 Winter	$8.42	$8.06	$8.11	$0.36	$0.31	$0.05
03-04 Winter	$8.03	$7.42	$7.67	$0.61	$0.36	$0.24

Source: Gas Daily Average Daily Prices

Phase III Value Creation Since In-Service Date
Maximum Market Price Scenario
Algonquin versus Dracut
11/25/03-3/31/04

MDQ (Dth) 300,000

	Algonquin ($/Dth)	Dracut ($/Dth)	Maximum Market Price ($/Dth)	Incremental Margin (Max- Dracut) ($/Dth)	Total Incremental Value Over Dracut ($)
11/24/2003	$4.51	4.46	$4.51	$0.05	$16,500
11/25/2003	$5.31	5.18	$5.31	$0.13	$39,000
11/26/2003	$5.18	5.02	$5.18	$0.16	$48,000
11/27/2003	$5.78	5.44	$5.78	$0.34	$102,000
11/28/2003	$5.78	5.44	$5.78	$0.34	$102,000
11/29/2003	$5.78	5.44	$5.78	$0.34	$102,000
11/30/2003	$5.78	5.44	$5.78	$0.34	$102,000
12/1/2003	$5.78	5.44	$5.78	$0.34	$102,000
12/2/2003	$7.01	6.54	$7.01	$0.47	$141,000
12/3/2003	$7.78	6.99	$7.78	$0.80	$238,500
12/4/2003	$6.42	5.83	$6.42	$0.59	$177,000
12/5/2003	$6.63	6.30	$6.63	$0.33	$97,500
12/6/2003	$7.35	7.18	$7.35	$0.17	$52,500
12/7/2003	$7.35	7.18	$7.35	$0.17	$52,500
12/8/2003	$7.35	7.18	$7.35	$0.17	$52,500
12/9/2003	$6.93	6.75	$6.93	$0.18	$52,500
12/10/2003	$7.21	6.97	$7.21	$0.25	$73,500
12/11/2003	$7.48	7.24	$7.48	$0.24	$72,000
12/12/2003	$7.43	7.05	$7.43	$0.38	$112,500
12/13/2003	$7.93	7.62	$7.93	$0.31	$93,000
12/14/2003	$7.93	7.62	$7.93	$0.31	$93,000
12/15/2003	$7.93	7.62	$7.93	$0.31	$93,000
12/16/2003	$7.35	7.10	$7.35	$0.25	$75,000
12/17/2003	$7.20	7.04	$7.20	$0.16	$49,500
12/18/2003	$7.30	6.85	$7.30	$0.45	$133,500
12/19/2003	$8.14	7.80	$8.14	$0.34	$100,500
12/20/2003	$7.66	7.18	$7.66	$0.48	$145,500
12/21/2003	$7.66	7.18	$7.66	$0.48	$145,500
12/22/2003	$7.66	7.18	$7.66	$0.48	$145,500
12/23/2003	$6.96	6.46	$6.96	$0.50	$150,000
12/24/2003	$5.90	5.53	$5.90	$0.38	$112,500
12/25/2003	$5.93	5.55	$5.93	$0.37	$112,500
12/26/2003	$5.93	5.55	$5.93	$0.37	$112,500
12/27/2003	$5.93	5.55	$5.93	$0.37	$112,500
12/28/2003	$5.93	5.55	$5.93	$0.37	$112,500
12/29/2003	$5.93	5.55	$5.93	$0.37	$112,500
12/30/2003	$5.80	5.58	$5.80	$0.23	$67,500
12/31/2003	$6.30	6.14	$6.30	$0.17	$49,500
1/1/2004	$6.23	5.90	$6.23	$0.32	$97,500
1/2/2004	$6.23	5.90	$6.23	$0.32	$97,500
1/3/2004	$6.23	5.90	$6.23	$0.32	$97,500
1/4/2004	$6.23	5.90	$6.23	$0.32	$97,500
1/5/2004	$6.23	5.90	$6.23	$0.32	$97,500
1/6/2004	$7.85	7.25	$7.85	$0.60	$180,000
1/7/2004	$8.88	8.73	$8.88	$0.15	$45,000
1/8/2004	$10.13	9.83	$10.13	$0.30	$90,000
1/9/2004	$11.83	11.75	$11.83	$0.08	$24,000
1/10/2004	$11.38	10.00	$11.38	$1.38	$412,500
1/11/2004	$11.38	10.00	$11.38	$1.38	$412,500
1/12/2004	$11.38	10.00	$11.38	$1.38	$412,500
1/13/2004	$9.13	7.74	$9.13	$1.39	$415,500
1/14/2004	$28.25	19.50	$28.25	$8.75	$2,625,000
1/15/2004	$56.50	50.00	$56.50	$6.50	$1,950,000
1/16/2004	$39.50	23.50	$39.50	$16.00	$4,800,000
1/17/2004	$10.25	9.50	$10.25	$0.75	$225,000
1/18/2004	$10.25	9.50	$10.25	$0.75	$225,000
1/19/2004	$10.25	9.50	$10.25	$0.75	$225,000
1/20/2004	$10.25	9.50	$10.25	$0.75	$225,000
1/21/2004	$8.38	9.40	$9.40	$0.00	$0

Source: Gas Daily Average Daily Prices

Phase III Value Creation Since In-Service Date
Maximum Market Price Scenario
Algonquin versus Dracut
11/25/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
1/22/2004	$7.60	7.10	$7.60	$0.50	$150,000
1/23/2004	$8.85	8.48	$8.85	$0.38	$112,500
1/24/2004	$10.50	9.38	$10.50	$1.13	$337,500
1/25/2004	$10.50	9.38	$10.50	$1.13	$337,500
1/26/2004	$10.50	9.38	$10.50	$1.13	$337,500
1/27/2004	$10.54	9.20	$10.54	$1.34	$400,500
1/28/2004	$12.25	12.50	$12.50	$0.00	$0
1/29/2004	$13.73	14.01	$14.01	$0.00	$0
1/30/2004	$11.05	8.87	$11.05	$2.18	$654,000
1/31/2004	$11.05	8.87	$11.05	$2.18	$654,000
2/1/2004	$8.15	7.35	$8.15	$0.80	$240,000
2/2/2004	$8.15	7.35	$8.15	$0.80	$240,000
2/3/2004	$6.55	6.45	$6.55	$0.10	$30,000
2/4/2004	$6.55	6.35	$6.55	$0.20	$60,000
2/5/2004	$6.75	6.55	$6.75	$0.20	$60,000
2/6/2004	$6.43	6.26	$6.43	$0.17	$51,000
2/7/2004	$6.33	6.25	$6.33	$0.07	$22,500
2/8/2004	$6.33	6.25	$6.33	$0.07	$22,500
2/9/2004	$6.33	6.25	$6.33	$0.07	$22,500
2/10/2004	$6.38	6.18	$6.38	$0.20	$58,500
2/11/2004	$6.38	5.98	$6.38	$0.40	$120,000
2/12/2004	$6.13	5.88	$6.13	$0.26	$76,500
2/13/2004	$6.01	5.76	$6.01	$0.25	$75,000
2/14/2004	$7.93	7.35	$7.93	$0.58	$172,500
2/15/2004	$7.93	7.35	$7.93	$0.58	$172,500
2/16/2004	$7.93	7.35	$7.93	$0.58	$172,500
2/17/2004	$7.93	7.35	$7.93	$0.58	$172,500
2/18/2004	$6.10	5.87	$6.10	$0.23	$70,500
2/19/2004	$5.85	5.73	$5.85	$0.13	$37,500
2/20/2004	$5.74	5.69	$5.74	$0.05	$15,000
2/21/2004	$5.79	5.60	$5.79	$0.19	$55,500
2/22/2004	$5.79	5.60	$5.79	$0.19	$55,500
2/23/2004	$5.79	5.60	$5.79	$0.19	$55,500
2/24/2004	$5.80	5.69	$5.80	$0.11	$33,000
2/25/2004	$5.78	5.68	$5.78	$0.10	$30,000
2/26/2004	$5.81	5.74	$5.81	$0.06	$19,500
2/27/2004	$5.66	5.55	$5.66	$0.11	$33,000
2/28/2004	$5.81	5.58	$5.81	$0.24	$70,500
2/29/2004	$5.81	5.58	$5.81	$0.24	$70,500
3/1/2004	$5.81	5.58	$5.81	$0.24	$70,500
3/2/2004	$5.67	5.49	$5.67	$0.18	$52,500
3/3/2004	$5.89	5.72	$5.89	$0.17	$49,500
3/4/2004	$5.87	5.72	$5.87	$0.15	$45,000
3/5/2004	$5.66	5.52	$5.66	$0.14	$40,500
3/6/2004	$5.93	5.78	$5.93	$0.15	$45,000
3/7/2004	$5.93	5.78	$5.93	$0.15	$45,000
3/8/2004	$5.93	5.78	$5.93	$0.15	$45,000
3/9/2004	$6.15	5.94	$6.15	$0.22	$64,500
3/10/2004	$6.03	5.83	$6.03	$0.20	$60,000
3/11/2004	$5.99	5.82	$5.99	$0.17	$51,000
3/12/2004	$6.05	5.82	$6.05	$0.23	$69,000
3/13/2004	$6.05	5.85	$6.05	$0.20	$61,500
3/14/2004	$6.05	5.85	$6.05	$0.20	$61,500
3/15/2004	$6.05	5.85	$6.05	$0.20	$61,500
3/16/2004	$6.32	6.18	$6.32	$0.15	$43,500
3/17/2004	$6.33	6.11	$6.33	$0.23	$67,500
3/18/2004	$6.35	6.21	$6.35	$0.15	$43,500
3/19/2004	$6.37	6.25	$6.37	$0.12	$36,000
3/20/2004	$6.22	6.06	$6.22	$0.16	$48,000
3/21/2004	$6.22	6.06	$6.22	$0.16	$48,000

Source: Gas Daily Average Daily Prices

Phase III Value Creation Since In-Service Date
Maximum Market Price Scenario
Algonquin versus Dracut
11/25/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
3/22/2004	$6.22	6.06	$6.22	$0.16	$48,000
3/23/2004	$6.18	6.04	$6.18	$0.15	$43,500
3/24/2004	$6.01	5.88	$6.01	$0.13	$37,500
3/25/2004	$5.84	5.78	$5.84	$0.06	$18,000
3/26/2004	$5.69	5.56	$5.69	$0.13	$39,000
3/27/2004	$5.58	5.42	$5.58	$0.16	$48,000
3/28/2004	$5.58	5.42	$5.58	$0.16	$48,000
3/29/2004	$5.58	5.42	$5.58	$0.16	$48,000
3/30/2004	$5.81	5.65	$5.81	$0.17	$49,500
3/31/2004	$6.04	5.85	$6.04	$0.19	$57,000
			Total Incremental Value Over Dracut		$23,349,000

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin ($/Dth)	Dracut ($/Dth)	Maximum Market Price ($/Dth)	Incremental Margin (Max- Dracut) ($/Dth)	Total Incremental Value Over Dracut ($)
4/1/2003	$5.80	$5.58	$5.80	$0.23	$67,500
4/2/2003	$5.60	$5.35	$5.60	$0.26	$76,500
4/3/2003	$5.57	$5.31	$5.57	$0.26	$78,000
4/4/2003	$5.53	$0.00	$5.53	$5.53	$1,657,500
4/5/2003	$5.69	$0.00	$5.69	$5.69	$1,705,500
4/6/2003	$5.69	$0.00	$5.69	$5.69	$1,705,500
4/7/2003	$5.69	$0.00	$5.69	$5.69	$1,705,500
4/8/2003	$6.17	$6.28	$6.28	$0.00	$0
4/9/2003	$6.70	$6.23	$6.70	$0.48	$142,500
4/10/2003	$6.55	$6.03	$6.55	$0.53	$157,500
4/11/2003	$6.13	$5.60	$6.13	$0.53	$157,500
4/12/2003	$5.97	$5.50	$5.97	$0.47	$139,500
4/13/2003	$5.97	$5.50	$5.97	$0.47	$139,500
4/14/2003	$5.97	$5.50	$5.97	$0.47	$139,500
4/15/2003	$5.71	$5.48	$5.71	$0.24	$70,500
4/16/2003	$6.20	$5.89	$6.20	$0.31	$93,000
4/17/2003	$6.58	$6.34	$6.58	$0.24	$72,000
4/18/2003	$6.13	$5.73	$6.13	$0.40	$118,500
4/19/2003	$6.13	$5.73	$6.13	$0.40	$118,500
4/20/2003	$6.13	$5.73	$6.13	$0.40	$118,500
4/21/2003	$6.13	$5.73	$6.13	$0.40	$118,500
4/22/2003	$6.06	$5.80	$6.06	$0.26	$76,500
4/23/2003	$6.14	$5.90	$6.14	$0.23	$70,500
4/24/2003	$6.11	$5.88	$6.11	$0.23	$69,000
4/25/2003	$6.00	$5.74	$6.00	$0.26	$78,000
4/26/2003	$5.85	$5.64	$5.85	$0.21	$63,000
4/27/2003	$5.85	$5.64	$5.85	$0.21	$63,000
4/28/2003	$5.85	$5.64	$5.85	$0.21	$63,000
4/29/2003	$5.71	$5.60	$5.71	$0.11	$31,500
4/30/2003	$5.59	$5.40	$5.59	$0.19	$57,000
5/1/2003	$5.69	$5.52	$5.69	$0.17	$51,000
5/2/2003	$5.71	$5.59	$5.71	$0.13	$37,500
5/3/2003	$5.69	$5.52	$5.69	$0.17	$49,500
5/4/2003	$5.69	$5.52	$5.69	$0.17	$49,500
5/5/2003	$5.69	$5.52	$5.69	$0.17	$49,500
5/6/2003	$5.75	$5.64	$5.75	$0.11	$31,500
5/7/2003	$6.14	$5.86	$6.14	$0.28	$82,500
5/8/2003	$5.93	$5.73	$5.93	$0.20	$60,000
5/9/2003	$6.03	$5.79	$6.03	$0.24	$70,500
5/10/2003	$6.00	$5.88	$6.00	$0.13	$37,500
5/11/2003	$6.00	$5.88	$6.00	$0.13	$37,500
5/12/2003	$6.00	$5.88	$6.00	$0.13	$37,500
5/13/2003	$6.29	$6.10	$6.29	$0.19	$57,000
5/14/2003	$6.35	$6.25	$6.35	$0.10	$30,000
5/15/2003	$6.57	$6.39	$6.57	$0.19	$55,500
5/16/2003	$6.68	$6.53	$6.68	$0.15	$46,500
5/17/2003	$6.29	$6.14	$6.29	$0.16	$46,500
5/18/2003	$6.29	$6.14	$6.29	$0.16	$46,500
5/19/2003	$6.29	$6.14	$6.29	$0.16	$46,500
5/20/2003	$6.40	$6.35	$6.40	$0.04	$13,500
5/21/2003	$6.39	$6.27	$6.39	$0.12	$36,000
5/22/2003	$6.58	$6.36	$6.58	$0.22	$64,500
5/23/2003	$6.57	$6.35	$6.57	$0.22	$66,000
5/24/2003	$6.44	$6.07	$6.44	$0.37	$111,000
5/25/2003	$6.44	$6.07	$6.44	$0.37	$111,000
5/26/2003	$6.44	$6.07	$6.44	$0.37	$111,000
5/27/2003	$6.44	$6.07	$6.44	$0.37	$111,000
5/28/2003	$6.33	$6.18	$6.33	$0.15	$43,500
5/29/2003	$6.13	$5.95	$6.13	$0.18	$52,500

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
5/30/2003	$6.06	$5.78	$6.06	$0.28	$82,500
5/31/2003	$6.35	$6.12	$6.35	$0.23	$69,000
6/1/2003	$6.35	$6.12	$6.35	$0.23	$69,000
6/2/2003	$6.35	$6.12	$6.35	$0.23	$69,000
6/3/2003	$6.69	$6.47	$6.69	$0.22	$66,000
6/4/2003	$6.67	$6.46	$6.67	$0.21	$63,000
6/5/2003	$6.89	$6.62	$6.89	$0.27	$79,500
6/6/2003	$6.44	$6.35	$6.44	$0.09	$27,000
6/7/2003	$6.61	$6.42	$6.61	$0.19	$57,000
6/8/2003	$6.61	$6.42	$6.61	$0.19	$57,000
6/9/2003	$6.61	$6.42	$6.61	$0.19	$57,000
6/10/2003	$6.57	$6.42	$6.57	$0.15	$45,000
6/11/2003	$6.45	$6.30	$6.45	$0.15	$45,000
6/12/2003	$6.39	$6.24	$6.39	$0.16	$46,500
6/13/2003	$6.30	$6.17	$6.30	$0.13	$39,000
6/14/2003	$5.74	$5.55	$5.74	$0.19	$55,500
6/15/2003	$5.74	$5.55	$5.74	$0.19	$55,500
6/16/2003	$5.74	$5.55	$5.74	$0.19	$55,500
6/17/2003	$5.83	$5.70	$5.83	$0.14	$40,500
6/18/2003	$6.05	$5.99	$6.05	$0.06	$18,000
6/19/2003	$5.93	$5.76	$5.93	$0.17	$49,500
6/20/2003	$5.86	$5.74	$5.86	$0.12	$36,000
6/21/2003	$6.20	$5.88	$6.20	$0.32	$96,000
6/22/2003	$6.20	$5.88	$6.20	$0.32	$96,000
6/23/2003	$6.20	$5.88	$6.20	$0.32	$96,000
6/24/2003	$6.57	$6.45	$6.57	$0.12	$36,000
6/25/2003	$6.51	$6.45	$6.51	$0.06	$18,000
6/26/2003	$6.28	$6.19	$6.28	$0.09	$27,000
6/27/2003	$6.11	$5.84	$6.11	$0.27	$81,000
6/28/2003	$5.65	$5.41	$5.65	$0.25	$73,500
6/29/2003	$5.65	$5.41	$5.65	$0.25	$73,500
6/30/2003	$5.65	$5.41	$5.65	$0.25	$73,500
7/1/2003	$5.89	$5.75	$5.89	$0.14	$40,500
7/2/2003	$5.63	$5.48	$5.63	$0.16	$46,500
7/3/2003	$5.40	$5.29	$5.40	$0.11	$33,000
7/4/2003	$5.29	$5.19	$5.29	$0.11	$31,500
7/5/2003	$5.29	$5.19	$5.29	$0.11	$31,500
7/6/2003	$5.29	$5.19	$5.29	$0.11	$31,500
7/7/2003	$5.29	$5.19	$5.29	$0.11	$31,500
7/8/2003	$5.81	$5.53	$5.81	$0.28	$84,000
7/9/2003	$6.10	$5.89	$6.10	$0.21	$63,000
7/10/2003	$6.07	$5.85	$6.07	$0.22	$66,000
7/11/2003	$5.82	$5.58	$5.82	$0.25	$73,500
7/12/2003	$5.59	$5.44	$5.59	$0.15	$46,500
7/13/2003	$5.59	$5.44	$5.59	$0.15	$46,500
7/14/2003	$5.59	$5.44	$5.59	$0.15	$46,500
7/15/2003	$5.67	$5.43	$5.67	$0.24	$70,500
7/16/2003	$5.66	$5.49	$5.66	$0.18	$52,500
7/17/2003	$5.45	$5.25	$5.45	$0.20	$58,500
7/18/2003	$5.41	$5.23	$5.41	$0.19	$55,500
7/19/2003	$5.38	$5.22	$5.38	$0.15	$46,500
7/20/2003	$5.38	$5.22	$5.38	$0.15	$46,500
7/21/2003	$5.38	$5.22	$5.38	$0.15	$46,500
7/22/2003	$5.52	$5.41	$5.52	$0.11	$33,000
7/23/2003	$5.54	$5.42	$5.54	$0.12	$34,500
7/24/2003	$5.37	$5.23	$5.37	$0.14	$42,000
7/25/2003	$5.38	$5.21	$5.38	$0.17	$51,000
7/26/2003	$5.08	$5.01	$5.08	$0.08	$22,500
7/27/2003	$5.08	$5.01	$5.08	$0.08	$22,500
7/28/2003	$5.08	$5.01	$5.08	$0.08	$22,500

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
7/29/2003	$5.08	$4.96	$5.08	$0.13	$37,500
7/30/2003	$5.20	$5.04	$5.20	$0.17	$49,500
7/31/2003	$5.14	$5.04	$5.14	$0.10	$30,000
8/1/2003	$5.03	$4.94	$5.03	$0.09	$27,000
8/2/2003	$5.06	$4.96	$5.06	$0.10	$30,000
8/3/2003	$5.06	$4.96	$5.06	$0.10	$30,000
8/4/2003	$5.06	$4.96	$5.06	$0.10	$30,000
8/5/2003	$5.20	$5.15	$5.20	$0.05	$15,000
8/6/2003	$5.23	$5.06	$5.23	$0.17	$49,500
8/7/2003	$5.24	$5.15	$5.24	$0.09	$27,000
8/8/2003	$5.27	$5.15	$5.27	$0.12	$34,500
8/9/2003	$5.43	$5.25	$5.43	$0.18	$52,500
8/10/2003	$5.43	$5.25	$5.43	$0.18	$52,500
8/11/2003	$5.43	$5.25	$5.43	$0.18	$52,500
8/12/2003	$5.57	$5.42	$5.57	$0.15	$45,000
8/13/2003	$5.59	$5.44	$5.59	$0.15	$45,000
8/14/2003	$5.71	$5.58	$5.71	$0.13	$39,000
8/15/2003	$5.80	$5.72	$5.80	$0.08	$22,500
8/16/2003	$5.35	$5.18	$5.35	$0.18	$52,500
8/17/2003	$5.35	$5.18	$5.35	$0.18	$52,500
8/18/2003	$5.35	$5.18	$5.35	$0.18	$52,500
8/19/2003	$5.51	$5.50	$5.51	$0.01	$3,000
8/20/2003	$5.63	$5.53	$5.63	$0.11	$31,500
8/21/2003	$5.61	$5.53	$5.61	$0.08	$22,500
8/22/2003	$5.62	$5.53	$5.62	$0.09	$28,500
8/23/2003	$5.64	$5.58	$5.64	$0.07	$19,500
8/24/2003	$5.64	$5.58	$5.64	$0.07	$19,500
8/25/2003	$5.64	$5.58	$5.64	$0.07	$19,500
8/26/2003	$5.75	$5.65	$5.75	$0.10	$30,000
8/27/2003	$5.59	$5.47	$5.59	$0.13	$37,500
8/28/2003	$5.58	$5.47	$5.58	$0.11	$33,000
8/29/2003	$5.31	$5.37	$5.37	$0.00	$0
8/30/2003	$5.31	$5.37	$5.37	$0.00	$0
8/31/2003	$5.31	$5.37	$5.37	$0.00	$0
9/1/2003	$5.23	$5.14	$5.23	$0.09	$27,000
9/2/2003	$5.23	$5.14	$5.23	$0.09	$27,000
9/3/2003	$5.00	$4.86	$5.00	$0.15	$43,500
9/4/2003	$5.07	$4.90	$5.07	$0.16	$49,500
9/5/2003	$0.00	$4.83	$4.83	$0.00	$0
9/6/2003	$5.07	$4.96	$5.07	$0.11	$31,500
9/7/2003	$5.07	$4.96	$5.07	$0.11	$31,500
9/8/2003	$5.07	$4.96	$5.07	$0.11	$31,500
9/9/2003	$5.18	$5.10	$5.18	$0.08	$24,000
9/10/2003	$5.09	$5.01	$5.09	$0.08	$24,000
9/11/2003	$5.15	$5.07	$5.15	$0.08	$24,000
9/12/2003	$5.18	$5.07	$5.18	$0.11	$31,500
9/13/2003	$4.93	$4.79	$4.93	$0.15	$43,500
9/14/2003	$4.93	$4.79	$4.93	$0.15	$43,500
9/15/2003	$4.93	$4.79	$4.93	$0.15	$43,500
9/16/2003	$5.02	$4.95	$5.02	$0.07	$22,500
9/17/2003	$5.06	$5.03	$5.06	$0.03	$7,500
9/18/2003	$5.05	$4.95	$5.05	$0.10	$30,000
9/19/2003	$4.91	$4.76	$4.91	$0.15	$43,500
9/20/2003	$4.70	$4.65	$4.70	$0.05	$15,000
9/21/2003	$4.70	$4.65	$4.70	$0.05	$15,000
9/22/2003	$4.70	$4.65	$4.70	$0.05	$15,000
9/23/2003	$4.80	$4.72	$4.80	$0.07	$22,500
9/24/2003	$5.01	$4.87	$5.01	$0.14	$42,000
9/25/2003	$5.08	$4.97	$5.08	$0.11	$33,000
9/26/2003	$4.95	$4.86	$4.95	$0.09	$27,000

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
MDQ (Dth)		300,000			
9/27/2003	$4.75	$4.68	$4.75	$0.07	$21,000
9/28/2003	$4.75	$4.68	$4.75	$0.07	$21,000
9/29/2003	$4.75	$4.68	$4.75	$0.07	$21,000
9/30/2003	$5.15	$5.02	$5.15	$0.13	$39,000
10/1/2003	$5.06	$5.02	$5.06	$0.04	$12,000
10/2/2003	$4.88	$4.95	$4.95	$0.00	$0
10/3/2003	$4.85	$4.80	$4.85	$0.05	$15,000
10/4/2003	$4.79	$4.69	$4.79	$0.10	$28,500
10/5/2003	$4.79	$4.69	$4.79	$0.10	$28,500
10/6/2003	$4.79	$4.69	$4.79	$0.10	$28,500
10/7/2003	$4.88	$4.79	$4.88	$0.09	$27,000
10/8/2003	$5.12	$5.06	$5.12	$0.06	$18,000
10/9/2003	$5.34	$5.18	$5.34	$0.16	$46,500
10/10/2003	$5.18	$5.06	$5.18	$0.12	$34,500
10/11/2003	$5.36	$5.26	$5.36	$0.10	$30,000
10/12/2003	$5.36	$5.26	$5.36	$0.10	$30,000
10/13/2003	$5.36	$5.26	$5.36	$0.10	$30,000
10/14/2003	$5.38	$5.27	$5.38	$0.11	$34,500
10/15/2003	$5.29	$5.29	$5.29	$0.00	$0
10/16/2003	$5.50	$5.40	$5.50	$0.10	$30,000
10/17/2003	$5.53	$5.45	$5.53	$0.08	$24,000
10/18/2003	$4.99	$4.87	$4.99	$0.12	$36,000
10/19/2003	$4.99	$4.87	$4.99	$0.12	$36,000
10/20/2003	$4.99	$4.87	$4.99	$0.12	$36,000
10/21/2003	$4.83	$4.81	$4.83	$0.01	$4,500
10/22/2003	$5.53	$5.37	$5.53	$0.16	$48,000
10/23/2003	$5.70	$5.64	$5.70	$0.06	$18,000
10/24/2003	$5.67	$5.46	$5.67	$0.21	$63,000
10/25/2003	$5.25	$5.01	$5.25	$0.24	$70,500
10/26/2003	$5.25	$5.01	$5.25	$0.24	$70,500
10/27/2003	$5.25	$5.01	$5.25	$0.24	$70,500
10/28/2003	$5.10	$4.98	$5.10	$0.12	$34,500
10/29/2003	$5.07	$4.98	$5.07	$0.08	$25,500
10/30/2003	$5.02	$4.95	$5.02	$0.07	$19,500
10/31/2003	$4.85	$4.75	$4.85	$0.11	$31,500
11/1/2003	$4.25	$4.17	$4.25	$0.08	$24,000
11/2/2003	$4.25	$4.17	$4.25	$0.08	$24,000
11/3/2003	$4.25	$4.17	$4.25	$0.08	$24,000
11/4/2003	$4.57	$4.36	$4.57	$0.22	$64,500
11/5/2003	$4.50	$4.40	$4.50	$0.10	$30,000
11/6/2003	$5.18	$5.10	$5.18	$0.08	$24,000
11/7/2003	$5.53	$5.37	$5.53	$0.16	$48,000
11/8/2003	$5.43	$5.04	$5.43	$0.39	$117,000
11/9/2003	$5.43	$5.04	$5.43	$0.39	$117,000
11/10/2003	$5.43	$5.04	$5.43	$0.39	$117,000
11/11/2003	$5.19	$5.09	$5.19	$0.10	$30,000
11/12/2003	$5.17	$5.12	$5.17	$0.05	$16,500
11/13/2003	$5.80	$5.50	$5.80	$0.30	$88,500
11/14/2003	$5.56	$5.30	$5.56	$0.26	$78,000
11/15/2003	$5.32	$5.11	$5.32	$0.21	$61,500
11/16/2003	$5.32	$5.11	$5.32	$0.21	$61,500
11/17/2003	$5.32	$5.11	$5.32	$0.21	$61,500
11/18/2003	$5.12	$4.96	$5.12	$0.16	$48,000
11/19/2003	$4.80	$4.79	$4.80	$0.01	$3,000
11/20/2003	$4.93	$4.88	$4.93	$0.05	$15,000
11/21/2003	$4.77	$4.77	$4.77	$0.00	$0
11/22/2003	$4.51	$4.46	$4.51	$0.05	$16,500
11/23/2003	$4.51	$4.46	$4.51	$0.05	$16,500
11/24/2003	$4.51	$4.46	$4.51	$0.05	$16,500
11/25/2003	$5.31	$5.18	$5.31	$0.13	$39,000

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
11/26/2003	$5.18	$5.02	$5.18	$0.16	$48,000
11/27/2003	$5.78	$5.44	$5.78	$0.34	$102,000
11/28/2003	$5.78	$5.44	$5.78	$0.34	$102,000
11/29/2003	$5.78	$5.44	$5.78	$0.34	$102,000
11/30/2003	$5.78	$5.44	$5.78	$0.34	$102,000
12/1/2003	$5.78	$5.44	$5.78	$0.34	$102,000
12/2/2003	$7.01	$6.54	$7.01	$0.47	$141,000
12/3/2003	$7.78	$6.99	$7.78	$0.80	$238,500
12/4/2003	$6.42	$5.83	$6.42	$0.59	$177,000
12/5/2003	$6.63	$6.30	$6.63	$0.33	$97,500
12/6/2003	$7.35	$7.18	$7.35	$0.17	$52,500
12/7/2003	$7.35	$7.18	$7.35	$0.17	$52,500
12/8/2003	$7.35	$7.18	$7.35	$0.17	$52,500
12/9/2003	$6.93	$6.75	$6.93	$0.18	$52,500
12/10/2003	$7.21	$6.97	$7.21	$0.25	$73,500
12/11/2003	$7.48	$7.24	$7.48	$0.24	$72,000
12/12/2003	$7.43	$7.05	$7.43	$0.38	$112,500
12/13/2003	$7.93	$7.62	$7.93	$0.31	$93,000
12/14/2003	$7.93	$7.62	$7.93	$0.31	$93,000
12/15/2003	$7.93	$7.62	$7.93	$0.31	$93,000
12/16/2003	$7.35	$7.10	$7.35	$0.25	$75,000
12/17/2003	$7.20	$7.04	$7.20	$0.16	$49,500
12/18/2003	$7.30	$6.85	$7.30	$0.45	$133,500
12/19/2003	$8.14	$7.80	$8.14	$0.34	$100,500
12/20/2003	$7.66	$7.18	$7.66	$0.48	$145,500
12/21/2003	$7.66	$7.18	$7.66	$0.48	$145,500
12/22/2003	$7.66	$7.18	$7.66	$0.48	$145,500
12/23/2003	$6.96	$6.46	$6.96	$0.50	$150,000
12/24/2003	$5.90	$5.53	$5.90	$0.38	$112,500
12/25/2003	$5.93	$5.55	$5.93	$0.37	$112,500
12/26/2003	$5.93	$5.55	$5.93	$0.37	$112,500
12/27/2003	$5.93	$5.55	$5.93	$0.37	$112,500
12/28/2003	$5.93	$5.55	$5.93	$0.37	$112,500
12/29/2003	$5.93	$5.55	$5.93	$0.37	$112,500
12/30/2003	$5.80	$5.58	$5.80	$0.23	$67,500
12/31/2003	$6.30	$6.14	$6.30	$0.17	$49,500
1/1/2004	$6.23	$5.90	$6.23	$0.32	$97,500
1/2/2004	$6.23	$5.90	$6.23	$0.32	$97,500
1/3/2004	$6.23	$5.90	$6.23	$0.32	$97,500
1/4/2004	$6.23	$5.90	$6.23	$0.32	$97,500
1/5/2004	$6.23	$5.90	$6.23	$0.32	$97,500
1/6/2004	$7.85	$7.25	$7.85	$0.60	$180,000
1/7/2004	$8.88	$8.73	$8.88	$0.15	$45,000
1/8/2004	$10.13	$9.83	$10.13	$0.30	$90,000
1/9/2004	$11.83	$11.75	$11.83	$0.08	$24,000
1/10/2004	$11.38	$10.00	$11.38	$1.38	$412,500
1/11/2004	$11.38	$10.00	$11.38	$1.38	$412,500
1/12/2004	$11.38	$10.00	$11.38	$1.38	$412,500
1/13/2004	$9.13	$7.74	$9.13	$1.39	$415,500
1/14/2004	$28.25	$19.50	$28.25	$8.75	$2,625,000
1/15/2004	$56.50	$50.00	$56.50	$6.50	$1,950,000
1/16/2004	$39.50	$23.50	$39.50	$16.00	$4,800,000
1/17/2004	$10.25	$9.50	$10.25	$0.75	$225,000
1/18/2004	$10.25	$9.50	$10.25	$0.75	$225,000
1/19/2004	$10.25	$9.50	$10.25	$0.75	$225,000
1/20/2004	$10.25	$9.50	$10.25	$0.75	$225,000
1/21/2004	$8.38	$9.40	$9.40	$0.00	$0
1/22/2004	$7.60	$7.10	$7.60	$0.50	$150,000
1/23/2004	$8.85	$8.48	$8.85	$0.38	$112,500
1/24/2004	$10.50	$9.38	$10.50	$1.13	$337,500

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth) 300,000

	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
1/25/2004	$10.50	$9.38	$10.50	$1.13	$337,500
1/26/2004	$10.50	$9.38	$10.50	$1.13	$337,500
1/27/2004	$10.54	$9.20	$10.54	$1.34	$400,500
1/28/2004	$12.25	$12.50	$12.50	$0.00	$0
1/29/2004	$13.73	$14.01	$14.01	$0.00	$0
1/30/2004	$11.05	$8.87	$11.05	$2.18	$654,000
1/31/2004	$11.05	$8.87	$11.05	$2.18	$654,000
2/1/2004	$8.15	$7.35	$8.15	$0.80	$240,000
2/2/2004	$8.15	$7.35	$8.15	$0.80	$240,000
2/3/2004	$6.55	$6.45	$6.55	$0.10	$30,000
2/4/2004	$6.55	$6.35	$6.55	$0.20	$60,000
2/5/2004	$6.75	$6.55	$6.75	$0.20	$60,000
2/6/2004	$6.43	$6.26	$6.43	$0.17	$51,000
2/7/2004	$6.33	$6.25	$6.33	$0.07	$22,500
2/8/2004	$6.33	$6.25	$6.33	$0.07	$22,500
2/9/2004	$6.33	$6.25	$6.33	$0.07	$22,500
2/10/2004	$6.38	$6.18	$6.38	$0.20	$58,500
2/11/2004	$6.38	$5.98	$6.38	$0.40	$120,000
2/12/2004	$6.13	$5.88	$6.13	$0.26	$76,500
2/13/2004	$6.01	$5.76	$6.01	$0.25	$75,000
2/14/2004	$7.93	$7.35	$7.93	$0.58	$172,500
2/15/2004	$7.93	$7.35	$7.93	$0.58	$172,500
2/16/2004	$7.93	$7.35	$7.93	$0.58	$172,500
2/17/2004	$7.93	$7.35	$7.93	$0.58	$172,500
2/18/2004	$6.10	$5.87	$6.10	$0.23	$70,500
2/19/2004	$5.85	$5.73	$5.85	$0.13	$37,500
2/20/2004	$5.74	$5.69	$5.74	$0.05	$15,000
2/21/2004	$5.79	$5.60	$5.79	$0.19	$55,500
2/22/2004	$5.79	$5.60	$5.79	$0.19	$55,500
2/23/2004	$5.79	$5.60	$5.79	$0.19	$55,500
2/24/2004	$5.80	$5.69	$5.80	$0.11	$33,000
2/25/2004	$5.78	$5.68	$5.78	$0.10	$30,000
2/26/2004	$5.81	$5.74	$5.81	$0.06	$19,500
2/27/2004	$5.66	$5.55	$5.66	$0.11	$33,000
2/28/2004	$5.81	$5.58	$5.81	$0.24	$70,500
2/29/2004	$5.81	$5.58	$5.81	$0.24	$70,500
3/1/2004	$5.81	$5.58	$5.81	$0.24	$70,500
3/2/2004	$5.67	$5.49	$5.67	$0.18	$52,500
3/3/2004	$5.89	$5.72	$5.89	$0.17	$49,500
3/4/2004	$5.87	$5.72	$5.87	$0.15	$45,000
3/5/2004	$5.66	$5.52	$5.66	$0.14	$40,500
3/6/2004	$5.93	$5.78	$5.93	$0.15	$45,000
3/7/2004	$5.93	$5.78	$5.93	$0.15	$45,000
3/8/2004	$5.93	$5.78	$5.93	$0.15	$45,000
3/9/2004	$6.15	$5.94	$6.15	$0.22	$64,500
3/10/2004	$6.03	$5.83	$6.03	$0.20	$60,000
3/11/2004	$5.99	$5.82	$5.99	$0.17	$51,000
3/12/2004	$6.05	$5.82	$6.05	$0.23	$69,000
3/13/2004	$6.05	$5.85	$6.05	$0.20	$61,500
3/14/2004	$6.05	$5.85	$6.05	$0.20	$61,500
3/15/2004	$6.05	$5.85	$6.05	$0.20	$61,500
3/16/2004	$6.32	$6.18	$6.32	$0.15	$43,500
3/17/2004	$6.33	$6.11	$6.33	$0.23	$67,500
3/18/2004	$6.35	$6.21	$6.35	$0.15	$43,500
3/19/2004	$6.37	$6.25	$6.37	$0.12	$36,000
3/20/2004	$6.22	$6.06	$6.22	$0.16	$48,000
3/21/2004	$6.22	$6.06	$6.22	$0.16	$48,000
3/22/2004	$6.22	$6.06	$6.22	$0.16	$48,000
3/23/2004	$6.18	$6.04	$6.18	$0.15	$43,500
3/24/2004	$6.01	$5.88	$6.01	$0.13	$37,500

Source: Gas Daily Average Daily Prices

Phase III Value Creation, Projected
Maximum Market Price Scenario
Algonquin versus Dracut
04/01/03-3/31/04

MDQ (Dth)		300,000			
	Algonquin	Dracut	Maximum Market Price	Incremental Margin (Max- Dracut)	Total Incremental Value Over Dracut
3/25/2004	$5.84	$5.78	$5.84	$0.06	$18,000
3/26/2004	$5.69	$5.56	$5.69	$0.13	$39,000
3/27/2004	$5.58	$5.42	$5.58	$0.16	$48,000
3/28/2004	$5.58	$5.42	$5.58	$0.16	$48,000
3/29/2004	$5.58	$5.42	$5.58	$0.16	$48,000
3/30/2004	$5.81	$5.65	$5.81	$0.17	$49,500
3/31/2004	$6.04	$5.85	$6.04	$0.19	$57,000
			Total Incremental Value Over Dracut		$41,262,000

Source: Gas Daily Average Daily Prices