STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc. d/b/a KeySpan) Energy Delivery New England)	DG 07-__

DIRECT TESTIMONY OF

Theodore Poe, Jr.

ON BEHALF OF

ENERGY NORTH NATURAL GAS, INC. d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND

September 14, 2007

I. INTRODUCTION

Q. Please state your name and business address?

A. My name is Theodore Poe, Jr. My business address is 52 Second Avenue, Waltham, MA 02451.

Q. What is your position with KeySpan Energy Delivery New England?

A. I am the Manager of Energy Planning with responsibility for projecting the resource requirements for the local gas distribution companies that operate as KeySpan Energy Delivery New England, including EnergyNorth Natural Gas, Inc. ("EnergyNorth"). For the purpose of this testimony, "KeySpan" or the "Company" will refer to EnergyNorth unless otherwise indicated.

Q. Please summarize your educational background and your professional experience?

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science Degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston where I was responsible for developing a variety of computer-forecasting models to analyze natural gas supply and demand for interstate pipeline and local distribution companies. I joined Boston Gas Company in 1989 and I have been responsible for modeling and forecasting the natural-gas resource requirements of customers and managing the resource-planning process. In 1998, I assumed the same responsibility for Essex Gas Company. In 1999, I assumed that responsibility for

Colonial Gas Company, and, in 2001, I assumed that responsibility for EnergyNorth.

Q. Are you a member of any professional organizations?

A. I am a member of the Northeast Gas Association, the New England-Canada Business Council, and the American Meteorological Society.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I have testified in a number of proceedings before the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Board and the New Hampshire Public Utilities Commission (the "Commission"). In New Hampshire these appearances include the Company's semi annual cost of gas proceedings from 2001 to the present and the Company's Integrated Resource Plan ("IRP") in Docket DG 04-133. I also played a key role in the development of KeySpan's IRP, which is pending before the New Hampshire Public Utilities Commission in docket DG 06-105.

In Massachusetts, I have testified in a number of proceedings, including Boston Gas Company, D.P.U./D.T.E. 97-104 (approval of contract restructuring); Boston Gas Company, D.P.U./D.T.E 97-99 (Long-Range Resource and Requirements Plan), KeySpan Energy Delivery New England; D.T.E. 01-105 (consolidated Massachusetts Long Range Resource and Requirements Plan); KeySpan Energy Delivery New England, D.T.E. 02-18 (approval of firm transportation agreements); KeySpan Energy Delivery New England E.F.S.B. 02-1 (approval to construct underground natural gas pipeline on Cape Cod); KeySpan Energy Delivery New

England, D.T.E. 05-35 (approval of the Tennessee ConneXion project firm transportation agreements); KeySpan Energy Delivery New England, D.T.E 05-68 (Long-Range Resource and Requirements Plan); KeySpan Energy Delivery New England, E.F.S.B.05-2 (approval to construct underground natural gas pipeline on Cape Cod), and KeySpan Energy Delivery New England, D.T.E. 06-54 (approval of long-term firm transportation agreements).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to demonstrate that the proposed arrangement with Tennessee Gas Pipeline Company ("Tennessee"): (1) is consistent with the resource requirements established in the Company's most recently filed IRP, which is pending before the Commission in Docket DG 06-105, and (2) compares favorably to the range of alternatives reasonably available to the Company to serve its customers. Each of these two elements is discussed in Section II and III, below.

In support of this demonstration, my testimony provides an analysis of KeySpan's resource requirements, which indicate a need for additional interstate pipeline capacity. Second, my testimony provides an overview of the comprehensive analysis the Company conducted to support its decision to enter into an arrangement with Tennessee to provide the Company with up to 30,000 MMBtu/day of incremental transportation capacity along the Concord Lateral for delivery to EnergyNorth customers (the "Proposed Agreement").

II. CONSISTENCY WITH PORTFOLIO OBJECTIVES

Q. Would you please describe the forecasting approach underlying the IRP?

A. Yes. KeySpan developed the five-year forecast of customer requirements for the period November 1, 2006 through October 31, 2011, under design-weather planning conditions, using a multi-step process that involved the following: (1) development of a forecast of incremental sendout, which is the additional sendout anticipated to occur over the forecast period above the level experienced in a reference year (2005-06); (2) normalization of the actual reference-year sendout through a regression analysis; (3) preparation of a normalized forecast of customer requirements which is the sum of incremental sendout plus the normalized reference year sendout; (4) determination of design-weather planning standards; and (5) establishment of forecasted customer requirements under design-weather conditions.

Q. Based on the forecasted sendout and resource requirements reflected in the IRP, how did the Company determine that there is a need for additional pipeline capacity in the KeySpan resource portfolio?

A. To meet customer needs, the Company plans for and procures gas resources (interstate pipeline, underground storage and on-system supplemental capacity) based on two perspectives: (1) by determining the amount of gas supply that would be required to meet the needs of customers under all reasonable weather conditions over an annual period ("design year"); and (2) by determining the amount of capacity that would be required to ensure sufficient deliveries to serve customers under severe weather conditions on any given day of the winter season ("design" or "peak" day). The Company has a degree of flexibility in meeting the "design year" needs of the system because there are days during the winter season when the Company can rely on short-term arrangements and market-area purchases to obtain gas supply, which ensure the Company's underground storage and on-system LNG inventories will be available for use on the coldest days. However, although short-term or market-area purchases represent a cost-effective way to supplement the Company's available gas-supply resources over the course of the winter season, the Company's planning process does not rely on these resources to provide city gate deliverability on any given day under the coldest weather conditions. On a design (or peak) day, the Company's planning process relies solely on its available on-system and off-system resources to deliver gas into the system to meet the needs of customers. Gas supply entering the distribution system is either transported to the city gate using pipeline capacity or is injected into the system as vaporized liquefied natural gas ("LNG") or propane through on-system facilities.

Thus, to meet customer requirements under design-day conditions, the Company must have in place sufficient capacity entitlements to ensure deliveries of pipeline gas and underground storage supplies to the city gate, as well as sufficient on-system gas inventories and vaporization capabilities to supplement those delivered supplies. In order to ensure that the resource portfolio encompasses adequate resources to meet customer requirements under design weather conditions, the Company evaluates: (1) the peak-day pipeline deliverability available to the Company at its city gates, which will be used in combination with on-system LNG and propane vaporization capabilities to ensure gas deliveries on the peak day; and (2) the amount of gas supply available to the Company over the peak season, which is provided through a combination of pipeline deliveries and on-system liquid inventories.

Using this approach, a citygate capacity shortfall is signaled where the analysis shows that: (1) on the design day, there is an insufficient amount of city gate capacity to ensure the level of throughput needed to meet sendout requirements in combination with on-system facilities, or (2) over the design season, there is a gap between the level of city gate deliverability available to provide gas supply to the system and the level of on-system inventories available to supply customers. As described below, KeySpan's analysis indicates that there will be a design season need beginning in 2008/09 and a design day need beginning in 2009/2010.

Q. Could you please review the Company's design-day resource requirements?

A. Yes. Chart IV-D-3 from the Company's IRP, which is attached hereto as Exhibit TEP-1, is a design-day resource analysis to evaluate the Company's city gate delivery capabilities on the peak day over the forecast period. Available resources are compared to the forecasted sendout requirements on the design day, making the following assumptions: (1) that all resources within the portfolio are used interchangeably to meet KeySpan customer requirements subject to operational and contractual constraints; (2) that any portfolio resources with contract terms expiring during the forecast period will be renewed and (3) that peak season resources will be supplemented with winter-liquid refills. Based on these assumptions, the analysis demonstrates a minimum need for incremental peak-day delivery capability totaling 5,310 MMBtu/day on the peak day beginning in 2009/10, increasing to 19,660 MMBtu/day by 2010/11. This capacity need is indicated in Exhibit TEP-1 as "Other Purchased Resources."

Q. Did the Company also prepare an analysis to determine whether there is a need for additional city gate deliverability over the peak season?

Yes. As stated above, the IRP signals a need for additional city gate gas deliveries where there is a gap between the level of city gate deliverability available to provide gas supply to the system and the level of on-system inventories available to supply customers during the design season. This analysis is shown on Exhibit TEP-2, which is a copy of Chart IV-D-1 from the Company's IRP. This analysis demonstrates a minimum need for incremental peak-season supply totaling 53,300 MMBtu beginning in 2008/09, increasing to 128,000 MMBtu/day by 2010/11. This supply need is indicated in Exhibit TEP-2 as "Other Purchased Resources."

In both the peak day and the peak season need, I refer to the "need" as the minimum requirement over and above the maximal use of the Company's existing resource portfolio as determined by the Company's SENDOUT® model. Because the only alternative resource modeled in the Company's IRP filing was the "Other Purchased Resource" supply (a very high-priced resource), SENDOUT® will determine the maximum use of the existing resource portfolio and the minimum incremental use of the high-priced alternative. This dynamic is important to note because the results presented in Section III, below, show that by factoring in more realistic modeling alternatives, the Company could use a greater level of incremental resource to achieve a lower overall cost of the resource portfolio.

III. COMPARISON WITH RESOURCE ALTERNATIVES

Q. What specific alternatives did the Company evaluate to meet the need for additional resources?

A. The Company investigated four alternatives to satisfy its growing resource need:

1. The Proposed Agreement with Tennessee adding 30,000 MMBtus/day of incremental capacity. This alternative would require Tennessee to complete the Concord Lateral Upgrade to add sufficient compression to make incremental capacity available to the Company.

2. The addition of LNG facilities (with and without liquefaction), which would add 25,000 dth/day MDQ, 300,000 dth ACQ (backfilled by a DOMAC liquid contract, delivered by a Transgas contract, in the case of the no-liquefaction configuration), sited on the existing LNG site in Concord, NH (the "LNG Project Alternative");

3. The addition of propane facilities, which would add 25,200 dth/day MDQ, 300,000 dth ACQ (backfilled in the peak season), with one unit sited on the 200 psig system in Concord (15,000 dth/day) and one unit sited on the 200 psig system in Nashua (10,200 dth/day) ("the Propane Project Alternative"); and

4. Implementation of demand-side management ("DSM") options.

As discussed in the testimony of Ms. Arangio and Mr. Stavrakas, these were the only options open to the Company in meeting the identified need for peak day and peak season capacity and associated gas supply.

Q. How were the costs of each of the alternatives determined?

A. The costs for the LNG and Propane Project Alternatives were developed by the Company's engineering group and are set forth in Exhibit JSS-1, as well as Exhibit TEP-3 accompanying my testimony. The cost associated with the implementation of DSM to meet the identified need was developed by the Company's Energy Management Group and is set forth in Exhibit TEP-4.

The cost of the Proposed Agreement is established in a letter dated July 24, 2007 from Tennessee to the Company, which is attached as Exhibit TEP-5. Please note that this letter memorialized a pricing arrangement that was discussed by Tennessee and the Company well in advance of July 24, 2007, and therefore was incorporated into the Company's alternatives analysis from the outset.

Q. From an overall perspective, how did the Company approach its comparative analysis in terms of annualized costs?

A. In this case, the decision to choose among the project alternatives was an important one because it would effectively dictate the reliability and economics of gas service for New Hampshire customers over the long-term planning horizon. Therefore, the Company found it necessary to go beyond its traditional comparative analysis of annualized costs and non-price factors. Specifically, the Company found it necessary to develop a methodology that would allow for a full assessment of the way in which the project alternatives would be used over time to serve customer load in view of a range of possible demand and price scenarios. The Company recognized that this more dynamic, multi-dimensional analytical approach would help to ensure that the most cost-effective alternative would be selected to the long-term benefit of customers.

A. What is the methodology that the Company devised for determining what the least-cost alternative would be over time?

A. Traditionally, the Company relies on its SENDOUT® model of the EnergyNorth system to evaluate least-cost utilization of the existing portfolio and of incremental resources. The SENDOUT® model is a well-established modeling system that takes the physical and pricing parameters of the various components of the ENGI portfolio and, through use of a linear-programming matrix, can identify least-cost utilization of those components. However, there are limitations to the use of SENDOUT® that arise in certain circumstances because the SENDOUT® model can be inflexible and difficult to interpret without substantial training and practical experience. Because the Company sought a higher level of flexibility and transparency in the project alternatives analysis, the Company developed a linear-programming model (the "LP Model") to generate results in a more readily understandable format, although still consistent with the output that would be available through SENDOUT®.

Q. How did the Company approach the task of devising the LP Model?

A. The Company developed the LP Model of the ENGI system using the GNU Linear Programming Kit ("GLPK"). GLPK is an open-source software package that is intended for use in solving large-scale linear-programming problems by means of the revised simplex method. Programs developed for GLPK, such as the Company's ENGI model, can be written in GNU MathProg language, which is a subset of the well-known AMPL linear-programming language. The source code, the executable images, and the documentation of GLPK version 4.9 is available for the Windows operating system at its Sourceforge website (http://gnuwin32.sourceforge.net/packages/glpk.htm). Models written in MathProg are simple text files that can be read and evaluated. The key decision variables of the LP Models can be found in Exhibit TEP-6(A).

After developing the LP Model, the Company generated its analysis using a range of demand and pricing assumptions. Each set of demand and price variables represents a unique model scenario.

Q. What are the demand scenarios investigated by the Company?

A. The Company investigated three design-year demand scenarios to determine the size of the incremental capacity addition that would be required. The design years 2007/08, 2009/10, and 2011/12 were generated in Q3 2007 as a part of the Company's annual planning cycle and constitute the same forecasts the Company relied upon for its 2007/08 Peak Period COG filing. Each demand scenario contains the daily customer requirements for all customers using utility capacity.

Q. What are the commodity cost variables used by the Company in its pricing scenarios?

A. The two commodity cost variables required for modeling the Company's portfolio are the NYMEX commodity cost for natural gas and the commodity cost for propane at Mt. Belvieu, TX. The Company relied on the U.S. Department of

Energy EIA *Annual Energy Outlook (Feb 2007)* ('AEO') for forecasted annual average prices for NYMEX. The Company then seasonalized these prices using the monthly price distribution from the 2002/03 split year, the most recent year where overall design year weather conditions occurred.

Since the AEO report did not directly forecast propane commodity prices, the Company used the AEO forecast for low-sulfur imported crude oil. From 1998-2005, the propane commodity price per gallon at Mt. Belvieu averaged approximately 75 percent of the price of a gallon of West Texas Intermediate crude oil, which in turn is priced at approximately the same value as low-sulfur imported crude oil. Only recently has that propane-to-crude oil ratio dropped to approximately 65 percent.

In addition, the Company used the current 65 percent ratio as the reference price for propane, and performed sensitivity analyses with that ratio ranging from 75 percent and to as low as 55 percent. Again, the annual average prices were seasonalized using the monthly price distribution from 2002/03.

Q. What are the three pricing scenarios investigated by the Company in its alternatives analysis?

A. The Company investigated three price scenarios from the AEO 2007 forecast: Reference Case, High Case, and Low Case (Exhibit TEP-6(B)). Additionally, the Company investigated two interstate transportation market scenarios:

- Unconstrained Transportation Market: USGC, Dawn and Niagara basis is zero, while TGP Z6 and Transco Z6 NY are $0.60/dth year-round; and,

- Constrained Transportation Market: USGC, Dawn and Niagara basis is zero, while TGP Z6 and Transco Z6 NY are $0.60/dth Apr-Oct and then $2.30/dth Nov-Mar.

These two transportation market scenarios were defined in the analysis because the Northeast natural gas market is currently a constrained market during the peak period. However, peak-period pricing may be influenced in the future by the introduction of new LNG supply sources in New England and Eastern Canada, which could mitigate those constraints. Therefore, the Company's analysis factored in both market scenarios.

In evaluating the project alternatives identified above using the LP Model, the Company omitted Alternative 4 (DSM) because, as described in Exhibit TEP-4, the throughput reductions associated with the Company's existing energy efficiency programs are implicitly incorporated in the model through a reduction in forecasted demand. Moreover, the customer participation rates needed to achieve incremental savings over and above those included in the model that would be necessary to offset the forecasted resource requirement are not realistically achievable. Therefore, the Company performed its methodological survey in relation to the three remaining project alternatives.

Q. Were any other variables incorporated into the LP Model?

A. Yes. To adequately describe the Company's resource portfolio, the LP Model includes variables for the maximum daily quantities ("MDQ") and annual contract quantities ("ACQ," if relevant) for the existing and proposed resources (Exhibit

TEP-6(A)). The LP Model will specify, for the least-cost use, the optimum magnitude of each of these variables in its output.

Q. Would you please summarize the results of your analysis?

A. In total, the Company analyzed 11 demand/price scenarios (Exhibit TEP-6(C)) with the Company's existing resources and project alternatives as variables. In addition, the Company analyzed two scenarios where only the existing resources and an incremental, high-priced "spot" source were available. Lastly, in order to confirm the Company's preliminary identification of the Proposed Agreement as the incremental resource with the least cost from an annualized perspective and best weighting of non-price factors, the Company analyzed two scenarios where only the existing portfolio resources and the Proposed Agreement were available.

From an overall perspective, the result of any given model scenario is the determination of the MDQ (or ACQ in certain cases) by supply source that results in the lowest overall annual portfolio cost. Exhibit TEP-6(D), Table 2a, shows the model results for the 11 demand/price scenarios in which the LNG, propane, and Concord Lateral upgrade alternatives were available. Exhibit TEP-6(D), Table 2a, also includes as a reference the two scenarios in which high-priced "spot" supply was available instead of these alternatives. Exhibit TEP-6(D), Table 2b, shows the model results for the 11 demand/price scenarios in which the LNG, propane, and Concord Lateral upgrade alternatives were available. Exhibit TEP-6(D), Table 2b, also includes as a reference the two scenarios in which the proposed 30,000 MMBtu/day capacity of the Concord Lateral upgrade was available instead of these alternatives.

Based on these conclusive results, for all 11 scenarios, the Company identified the Proposed Agreement/Concord Lateral Upgrade as the preferred project alternative, i.e., it represents the most reliable and least-cost resource available to meet the identified need for incremental capacity resources. In addition, because these results were based on the Constrained Transportation Market assumption, the Unconstrained Transportation Market assumption would further lower the delivered commodity cost of supply delivered via the Concord Lateral upgrade. Thus, the Company's analysis thoroughly confirmed the Proposed Agreement as the preferred project alternative.

Q. Can you explain why the LP Model would choose a 365-day pipeline option over the addition of supplemental facilities to meet what appears to be (at least in the short-term) a peaking need?

A. Yes. Pipeline expansions are "lumpy" investments by nature, meaning that the volumes purchased will generally be in excess of the volumes required in the early years of the identified need. However, as customer load growth occurs over time (as it inevitably does), the full entitlement is utilized on a cost-effective basis. This is especially true where the volumes available under the arrangement can be used in the early years to offset or supplant the use of more expensive LNG or propane supplies, which is currently the case on the EnergyNorth system. Once the incremental Tennessee volumes are made available to the portfolio, the LP Model shows that those volumes may be used to offset more expensive existing resources (even before the incremental capacity is "needed"), thereby reducing the total cost of the portfolio to customers as compared to the LNG or Propane Project Alternatives.

Q. Are there any other benefits to the Concord Lateral expansion?

A. Yes. As discussed in the testimony of Ms. Arangio, there are a number of important non-price factors that weigh heavily in favor of the Proposed Agreement. These factors are not accounted for in the LP Model, and therefore only widen the gap between the Proposed Agreement and other project alternatives in terms of representing the best possible solution to the identified resource need. From a planning and procurement perspective, the most significant non-price benefits stem from the fact that interstate pipeline capacity will provide access to new supply projects, including future TGP non-binding open seasons, long-haul projects, storage projects, Northeast LNG Projects (such as Canaport, Excelerate, Neptune), and other upstream projects that will come on line from time to time. The availability of these supplies will provide significant flexibility for the Company in purchasing least-cost supplies over the long term. Expansion of on-system facilities provides no such access, and therefore no such flexibility. In fact, reliance on these types of facilities to meet the incremental need could require substantially more trucking of propane and LNG during either or both of the off-peak and peak seasons, which is a supply dynamic that runs contrary to safe and reliable operation of the system given available infrastructure options.

On a last note, the Proposed Agreement has the added benefit of offsetting peak-period premiums paid to adhere to the Commission's 7-day storage requirement.

Q. **Does this conclude your prefiled testimony in this proceeding?**

A. Yes. It does.

EXHIBIT TEP - 1

Chart IV-D-3 from IRP

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year
(MMBtu)

Peak Day

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		138,600	142,000	144,800	147,700	151,000
Refill	Underground Storage	0	0	0	0	0
	LNG	2,000	2,000	2,000	2,000	2,000
	Propane	1,730	8,000	8,000	8,000	0
Total Requirements		142,330	152,000	154,800	157,700	153,000
RESOURCES						
PNGTS		160	160	160	160	160
TGP	AES-Londonderry	15,000	15,000	15,000	15,000	15,000
	ANE	3,970	3,970	3,970	3,970	3,970
	BP / Nexen	3,120	3,120	3,120	3,120	3,120
	CoEnergy	20,000	20,000	20,000	20,000	20,000
	Gulf Supply	21,600	21,600	21,600	21,600	21,600
	Market Area -- Zone 4	0	0	0	0	0
	Market Area -- Zone 6	0	0	0	0	0
	Storage	28,110	28,110	28,110	28,110	28,110
Other Purchased Resources		0	0	0	5,310	19,660
DOMAC	Vapor	8,000	8,000	8,000	8,000	8,000
	Liquid	2,000	2,000	2,000	2,000	2,000
LNG From Storage		3,770	7,100	9,900	7,530	5,810
Propane	Vapor	35,000	35,000	35,000	35,000	25,690
	Truck	1,730	8,000	8,000	8,000	0
Total Resources		142,460	152,060	154,860	157,800	153,120

EXHIBIT TEP - 2

Chart IV-D-1 from IRP

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		10,451,700	10,795,100	10,946,700	11,183,400	11,452,000
Refill	Underground Storage	200	0	0	0	0
	LNG	131,200	138,300	142,800	146,400	148,800
	Propane	93,400	93,400	93,500	93,500	93,500
Total Requirements		10,676,500	11,026,800	11,183,000	11,423,300	11,694,300
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	299,000	405,000	450,000	437,800	450,000
	ANE	584,700	597,200	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	447,200	450,200
	CoEnergy	1,784,000	1,783,900	1,783,900	1,784,000	1,784,000
	Gulf Supply	3,124,900	3,118,500	3,099,700	3,160,700	3,162,100
	Market Area -- Zone 4	560,300	746,600	802,900	853,500	937,400
	Market Area -- Zone 6	0	0	0	131,500	208,100
	Storage	2,483,900	2,471,600	2,472,400	2,487,700	2,487,700
Other Purchased Resources		0	0	53,300	48,000	128,000
DOMAC	Vapor	842,200	888,700	906,700	898,800	934,200
	Liquid	131,200	138,300	142,800	146,400	148,800
LNG From Storage		138,400	145,500	150,000	153,500	156,000
Propane	Vapor	166,600	166,600	166,700	166,600	140,400
	Truck	93,400	93,400	93,500	93,500	93,500
Total Resources		10,676,800	11,026,700	11,183,400	11,423,500	11,694,700

EXHIBIT TEP - 3

Resource Alternative 1: New LNG Facility (without liquefaction)

MDQ = 25,000 dth/day
ACQ = 300,000 dth

Annual Cost = $8,135,325

Trucking charge (currently $207,000/year for 2 dedicated trucks)
*$207,000/2*25 = $2,587,000*

Demand charge for DOMAC liquid (currently $987,500 for 50,000 dth)
*$987,500/50000*300000 = $5,925,000;*

*D1 = ($8,135,325+$2,587,000+$5,925,000)/(25000*365)=*
D1 = $1.8244/dth

Resource Alternative 2: New LNG Facility (with liquefaction)

MDQ = 25,000 dth/day
ACQ = 300,000 dth

Annual Cost = $11,007,428

*D1 = $11,007,428/(25000*365)=*
D1 = $1.2063/dth

Resource Alternative 3: New Propane Facility

MDQ = 25,200 dth/day
ACQ = 300,000 dth

Annual Cost = $6,451,308

*D2 = $6,451,308/(300000*365) =*
D2 = $0.0589/dth

CONCORD LATERAL / ON SYSTEM ALTERNATIVES

ITEM	PROPANE ($ in M)	LNG ($ in M)	LNG w/ Liquefaction ($ in M)	Comments / Assumptions
Capital Costs (Permitting, Engineering, Materials & Construction)				
LNG Storage Tank	$0.00	$23.80	$23.80	One LNG tank in Concord; storage capacity of 300,000 MMBtu.
Send Out LNG Pump Systems	$0.00	$1.24	$1.24	
LNG Vaporization Systems	$0.00	$0.90	$0.90	Total Vaporization Output Capacity of 25,200 MMBtu/day for LNG and Propane alternatives.
LNG Boiloff Systems	$0.00	$0.81	$0.81	
LNG Trucking Stations	$0.00	$1.56	$1.56	With Pump and Scale
Liquefaction at Concord LNG Facility	$0.00	$0.00	$14.00	3.0 MMSCFD liquefaction capacity.
Propane Storage Tanks	$8.34	$0.00	$0.00	One Propane tank in Concord (550 MMBtu/hr) and one in Nashua (500 MMBtu/hr). 300,000 MMBtu combined storage capacity.
Propane Refrigeration Systems	$1.97	$0.00	$0.00	
Propane Delivery Systems	$4.01	$0.00	$0.00	Total Vaporization Output Capacity of 25,200 MMBtu/day for LNG and Propane alternatives.
Air Delivery Systems	$2.56	$0.00	$0.00	
Propane Air Metering & Regulating (M&R) Station	$1.37	$0.00	$0.00	
Pipeline Connection to New Nashua Propane	$1.00	$0.00	$0.00	Parcel near Hudson Take Station. Install high pressure (planned uprated 185#) inlet and outlet steel piping within a 2,500' common trench.
Pipeline from new Nashua Propane to existing Bridge St., Nashua Plant	$2.50	$0.00	$0.00	Install high pressure steel main from new Nashua Propane Plant, approximately 1.8 miles, including a river crossing, to existing Bridge St., Nashua plant. This pipeline will allow mixed (LP/Air & Natural) gas from the new plant to be discharged into the 130 psig (soon to be 185 psig) and 60 psig distribution systems. In addition, the existing Bridge St., Nashua
Land Cost	$3.52	$0.00	$0.00	16 acres of land needed for the new propane facility in Nashua. Land Cost based on $5.05/s.f. as provided by market comparisons of local land parcels. Assume KeySpan's Concord site has enough land for either the new LNG (10 - 12 acres needed) or Propane (16 acres needed) facility.
Indirect Costs	$5.95	$9.34	$9.34	Permitting, Engineering, Design and Construction Management
Total Direct Cost	$31.22	$37.65	$51.65	
KeySpan Overhead	$6.65	$9.03	$12.39	Contractor Labor Overhead for Energy North is 48% (as of Jan. '07). This O/H was applied to 50% of project costs, excluding land.
GRAND TOTAL (Capital)	***$37.87***	***$46.68***	***$64.04***	
O&M Costs				
O&M Costs	$0.80	$1.00	$1.33	Administrative, Labor, Expenses, Utilities, etc.
Annual Insurance Costs	$0.20	$0.20	$0.20	Property & Liability Ins. Prepared by Tim Kiernan
Annual Taxes	$0.54	$0.84	$1.15	Prepared by Tom Laird
GRAND TOTAL (O&M)	***$1.54***	***$2.04***	***$2.68***	

NOTES:

Capital cost estimates shown above were provided by CHI Engineering, except for costs associated with: Land; Pipeline Connection to New Nashua Propane; Liquefaction; and Pipeline from new Nashua Propane to existing Bridge St., Nashua Plant.

EXHIBIT TEP - 4

Resource Alternative 4: Demand-Side Management

→ The Company incorporated the contribution of its existing Energy Efficiency Programs into its modeling through a reduction in the forecasted customer requirements.

→ To achieve an ACQ of 300,000 dekatherms, the Company referred to its 2005/06 "Annual Costs to Achieve" of $1,455,311 and its "Annual MMBtu Savings" of 73,187 MMBtu/year. Scaling the "Annual Costs to Achieve" by (300,000 / 73,187) yields an estimated cost of $5,964,000 per year.

→ To achieve this level of savings would require extraordinary rates of customer participation.

→ Also, DSM measures do not provide the guarantee of service that is associated with conventional supply-side resources because results are dependent upon customer adherence to conservation measures.

EXHIBIT TEP - 5

Resource Alternative 1: Proposed Agreement/Concord Lateral Upgrade

MDQ = 25,000 dth/day

D1 = $0.4800/dth

Note: The TGP precedent agreement offers 30,000 dth/day at a D1 rate of $0.40/dth. For consistency, the Company chose to initially model the TGP expansion at the same MDQ as the other alternatives (25,000 dth/day) and adjusted the unit D1 rate accordingly.

30,000 dth/day * $0.40/dth * 365 days = $4,380,000

$4,380,000 / (25,000 dth/day * 365 days) = $0.4800/dth

The Company executed its Precedent Agreement with TGP at the 30,000 dth/day level.

EXHIBIT TEP - 6

A. Summary of Key GLPK Variables

Table 1
Summary of Key GLPK Variables

Variable	Definition	Notes
MDQ_ANE	MDQ for the Dawn Ontario transportation path	
MDQ_BND	MDQ for the Niagara transportation path	
MDQ_LH	MDQ for the existing Tennessee long-haul transportation path	
MDQ_STG	MDQ for the combined underground storage transportation path	
MSQ_STG	MSQ for the combined underground storage	defined as 92 times MDQ_STG
MDQ_Z6	MDQ for the Tennessee-Dracut short-haul transportation path	
MDQ_Sem	MDQ for the city gate service supply	
MSQ_Sem	MSQ for the city gate service supply	defined as 151 times MDQ_Sem
MDQ_L0	MDQ for the existing LNG facilities	
MSQ_L0	MSQ for the existing LNG facilities	
MDQ_C3	MDQ for the existing LNG facilities	
MDQ_AES	MDQ for the supply sharing agreement	
MSQ_AES	MSQ for the supply sharing agreement	defined as 30 times MDQ_AES
MDQ_L1	MDQ for the alternative LNG facility (no liquefaction)	
MSQ_L1	MSQ for the alternative LNG facility (no liquefaction)	defined as 12 times MDQ_L1
MDQ_L2	MDQ for the alternative LNG facility (with liquefaction)	
MSQ_L2	MSQ for the alternative LNG facility (with liquefaction)	defined as 12 times MDQ_L2
MDQ_C3N	MDQ for the alternative propane facility	defined as MSQ_C3N / 11.905
MSQ_C3N	MSQ for the alternative propane facility	
MDQ_CL	MDQ for the alternative Concord Lateral expansion	
MDQ_Spot	MDQ for 'Other Purchased Resources'	

B. Pricing Scenarios

DOE EIA Annual Energy Outlook (Feb 2007) Forecasts
Mt. Belvieu at 55 percent of crude oil

	Reference Case			High Price Case			Low Price Case		
Year	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)
2004	41.61	5.90	0.545	41.61	5.90	0.545	41.61	5.90	0.545
2005	56.76	8.60	0.743	56.76	8.60	0.743	56.76	8.60	0.743
2006	71.22	7.29	0.933	71.22	7.29	0.933	71.22	7.29	0.933
2007	70.28	7.62	0.920	70.27	7.70	0.920	70.27	7.36	0.920
2008	68.76	7.69	0.900	71.91	8.08	0.942	66.39	7.36	0.869
2009	66.52	7.21	0.871	74.18	7.86	0.971	60.58	6.67	0.793
2010	63.87	6.98	0.836	77.22	7.71	1.011	54.54	6.23	0.714
2011	61.47	6.59	0.805	80.78	7.66	1.058	49.02	5.89	0.642
2012	59.57	6.51	0.780	84.05	7.34	1.101	44.39	5.59	0.581
2013	58.58	6.43	0.767	87.84	7.39	1.150	42.48	5.35	0.556
2014	59.14	6.58	0.774	92.17	7.55	1.207	41.66	5.37	0.546
2015	60.41	6.61	0.791	96.48	7.71	1.263	41.05	5.32	0.538
2016	61.33	6.86	0.803	100.85	8.03	1.321	41.61	5.58	0.545
2017	63.77	7.25	0.835	104.67	8.41	1.371	42.51	5.78	0.557
2018	65.52	7.26	0.858	108.48	8.26	1.421	43.46	5.90	0.569
2019	67.62	7.32	0.886	112.51	8.00	1.473	44.42	6.08	0.582
2020	68.99	7.57	0.903	116.62	8.45	1.527	45.38	6.21	0.594
2021	71.24	7.72	0.933	120.11	8.93	1.573	46.53	6.54	0.609
2022	73.62	8.06	0.964	123.21	9.24	1.613	47.76	6.95	0.625
2023	77.13	8.41	1.010	127.01	9.79	1.663	49.00	7.17	0.642
2024	79.74	8.81	1.044	130.92	10.05	1.714	50.27	7.60	0.658
2025	82.40	8.97	1.079	135.02	10.43	1.768	51.58	7.69	0.675
2026	85.09	9.19	1.114	139.24	10.98	1.823	52.87	8.02	0.692
2027	87.54	9.50	1.146	143.59	11.42	1.880	54.18	8.28	0.709
2028	90.02	9.90	1.179	148.07	11.93	1.939	55.54	8.53	0.727
2029	92.54	10.23	1.212	152.60	12.40	1.998	56.89	8.76	0.745
2030	95.17	10.49	1.246	157.34	13.00	2.060	58.31	9.04	0.764

DOE EIA Annual Energy Outlook (Feb 2007) Forecasts
Mt. Belvieu at 65 percent of crude oil

	Reference Case			High Price Case			Low Price Case		
Year	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)
2004	41.61	5.90	0.644	41.61	5.90	0.644	41.61	5.90	0.644
2005	56.76	8.60	0.878	56.76	8.60	0.878	56.76	8.60	0.878
2006	71.22	7.29	1.102	71.22	7.29	1.102	71.22	7.29	1.102
2007	70.28	7.62	1.088	70.27	7.70	1.088	70.27	7.36	1.087
2008	68.76	7.69	1.064	71.91	8.08	1.113	66.39	7.36	1.027
2009	66.52	7.21	1.029	74.18	7.86	1.148	60.58	6.67	0.938
2010	63.87	6.98	0.988	77.22	7.71	1.195	54.54	6.23	0.844
2011	61.47	6.59	0.951	80.78	7.66	1.250	49.02	5.89	0.759
2012	59.57	6.51	0.922	84.05	7.34	1.301	44.39	5.59	0.687
2013	58.58	6.43	0.907	87.84	7.39	1.359	42.48	5.35	0.657
2014	59.14	6.58	0.915	92.17	7.55	1.426	41.66	5.37	0.645
2015	60.41	6.61	0.935	96.48	7.71	1.493	41.05	5.32	0.635
2016	61.33	6.86	0.949	100.85	8.03	1.561	41.61	5.58	0.644
2017	63.77	7.25	0.987	104.67	8.41	1.620	42.51	5.78	0.658
2018	65.52	7.26	1.014	108.48	8.26	1.679	43.46	5.90	0.673
2019	67.62	7.32	1.047	112.51	8.00	1.741	44.42	6.08	0.687
2020	68.99	7.57	1.068	116.62	8.45	1.805	45.38	6.21	0.702
2021	71.24	7.72	1.102	120.11	8.93	1.859	46.53	6.54	0.720
2022	73.62	8.06	1.139	123.21	9.24	1.907	47.76	6.95	0.739
2023	77.13	8.41	1.194	127.01	9.79	1.966	49.00	7.17	0.758
2024	79.74	8.81	1.234	130.92	10.05	2.026	50.27	7.60	0.778
2025	82.40	8.97	1.275	135.02	10.43	2.090	51.58	7.69	0.798
2026	85.09	9.19	1.317	139.24	10.98	2.155	52.87	8.02	0.818
2027	87.54	9.50	1.355	143.59	11.42	2.222	54.18	8.28	0.838
2028	90.02	9.90	1.393	148.07	11.93	2.292	55.54	8.53	0.860
2029	92.54	10.23	1.432	152.60	12.40	2.362	56.89	8.76	0.881
2030	95.17	10.49	1.473	157.34	13.00	2.435	58.31	9.04	0.902

DOE EIA Annual Energy Outlook (Feb 2007) Forecasts
Mt. Belvieu at 75 percent of crude oil

	Reference Case			High Price Case			Low Price Case		
Year	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)	LowSulfur Imported Crude Price (cur $/bbl)	HenryHub Nat Gas Price (cur $/MMBtu)	Mt Belvieu Propane Price (cur $/gal)
2004	41.61	5.90	0.743	41.61	5.90	0.743	41.61	5.90	0.743
2005	56.76	8.60	1.014	56.76	8.60	1.014	56.76	8.60	1.014
2006	71.22	7.29	1.272	71.22	7.29	1.272	71.22	7.29	1.272
2007	70.28	7.62	1.255	70.27	7.70	1.255	70.27	7.36	1.255
2008	68.76	7.69	1.228	71.91	8.08	1.284	66.39	7.36	1.185
2009	66.52	7.21	1.188	74.18	7.86	1.325	60.58	6.67	1.082
2010	63.87	6.98	1.140	77.22	7.71	1.379	54.54	6.23	0.974
2011	61.47	6.59	1.098	80.78	7.66	1.443	49.02	5.89	0.875
2012	59.57	6.51	1.064	84.05	7.34	1.501	44.39	5.59	0.793
2013	58.58	6.43	1.046	87.84	7.39	1.568	42.48	5.35	0.759
2014	59.14	6.58	1.056	92.17	7.55	1.646	41.66	5.37	0.744
2015	60.41	6.61	1.079	96.48	7.71	1.723	41.05	5.32	0.733
2016	61.33	6.86	1.095	100.85	8.03	1.801	41.61	5.58	0.743
2017	63.77	7.25	1.139	104.67	8.41	1.869	42.51	5.78	0.759
2018	65.52	7.26	1.170	108.48	8.26	1.937	43.46	5.90	0.776
2019	67.62	7.32	1.208	112.51	8.00	2.009	44.42	6.08	0.793
2020	68.99	7.57	1.232	116.62	8.45	2.083	45.38	6.21	0.810
2021	71.24	7.72	1.272	120.11	8.93	2.145	46.53	6.54	0.831
2022	73.62	8.06	1.315	123.21	9.24	2.200	47.76	6.95	0.853
2023	77.13	8.41	1.377	127.01	9.79	2.268	49.00	7.17	0.875
2024	79.74	8.81	1.424	130.92	10.05	2.338	50.27	7.60	0.898
2025	82.40	8.97	1.471	135.02	10.43	2.411	51.58	7.69	0.921
2026	85.09	9.19	1.519	139.24	10.98	2.486	52.87	8.02	0.944
2027	87.54	9.50	1.563	143.59	11.42	2.564	54.18	8.28	0.967
2028	90.02	9.90	1.608	148.07	11.93	2.644	55.54	8.53	0.992
2029	92.54	10.23	1.652	152.60	12.40	2.725	56.89	8.76	1.016
2030	95.17	10.49	1.699	157.34	13.00	2.810	58.31	9.04	1.041

C. Summary of Demand/Price Scenarios

Demand/price scenarios with existing resources and project alternatives as variables.

Year	Price Scenario	Propane Price Ratio
2007/08	AEO Reference Case	65
2009/10	AEO Reference Case	65
	AEO High Case	75
	AEO High Case	55
	AEO Low Case	75
	AEO Low Case	55
2011/12	AEO Reference Case	65
	AEO High Case	75
	AEO High Case	55
	AEO Low Case	75
	AEO Low Case	55

Demand/price scenarios using existing resources and an incremental, high-priced 'spot' source.

Year	Price Scenario	Propane Price Ratio
2009/10	AEO Reference Case	65
2011/12	AEO Reference Case	65

Demand/price scenarios using existing resources and Proposed Agreement/Concord Lateral Upgrade

Year	Price Scenario	Propane Price Ratio
2009/10	AEO Reference Case	65
2011/12	AEO Reference Case	65

D. Results

Table 2a
Summary of Least-cost MDQ and MSQ for Key GLPK Variables

Variable	HighCase 55 2009/10	HighCase 75 2009/10	HighCase 55 2011/12	HighCase 75 2011/12
MDQ_ANE	4,000	4,000	4,000	4,000
MDQ_BND	3,122	3,122	3,122	3,122
MDQ_LH	21,596	21,596	21,596	21,596
MDQ_STG	28,115	28,115	28,115	28,115
MSQ_STG	2,586,580	2,586,580	2,586,580	2,586,580
MDQ_Z6	20,000	20,000	20,000	20,000
MDQ_Sem	8,000	8,000	8,000	8,000
MSQ_Sem	1,208,000	1,208,000	1,208,000	1,208,000
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	34,600	34,600	34,600	34,600
MDQ_AES	15,000	15,000	15,000	15,000
MSQ_AES	450,000	450,000	450,000	450,000
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	16,475	16,475	23,959	23,959
MDQ_Spot	0	0	0	0
Design Day Requirement	150,908	150,908	158,392	158,392

Variable	RefCase 65 2007/08	RefCase 65 2009/10	*Spot 65 2009/10*	RefCase 65 2011/12	*Spot 65 2011/12*
MDQ_ANE	4,000	4,000	*4,000*	4,000	*4,000*
MDQ_BND	3,122	3,122	*3,122*	3,122	*3,122*
MDQ_LH	21,596	21,596	*21,596*	21,596	*21,596*
MDQ_STG	28,115	28,115	*28,115*	28,115	*28,115*
MSQ_STG	2,586,580	2,586,580	*2,586,580*	2,586,580	*2,586,580*
MDQ_Z6	20,000	20,000	*20,000*	20,000	*20,000*
MDQ_Sem	8,000	8,000	*8,000*	8,000	*8,000*
MSQ_Sem	1,208,000	1,208,000	*1,208,000*	1,208,000	*1,208,000*
MDQ_L0	8,266	0	*0*	0	*0*
MSQ_L0	26,942	0	*0*	0	*0*
MDQ_C3	34,600	34,600	*34,600*	34,600	*21,535*
MDQ_AES	15,000	15,000	*15,000*	15,000	*15,000*
MSQ_AES	450,000	450,000	*450,000*	450,000	*450,000*
MDQ_L1	0	0	*0*	0	*0*
MSQ_L1	0	0	*0*	0	*0*
MDQ_L2	0	0	*0*	0	*0*
MSQ_L2	0	0	*0*	0	*0*
MDQ_C3N	0	0	*0*	0	*0*
MSQ_C3N	0	0	*0*	0	*0*
MDQ_CL	0	16,475	*0*	23,959	*0*
MDQ_Spot	0	0	*26,286* (*)	0	*37,024* (*)
Design Day Requirement	142,699	150,908	*150,908*	158,392	*158,392*

Variable	LowCase 55 2009/10	LowCase 75 2009/10	LowCase 55 2011/12	LowCase 75 2011/12
MDQ_ANE	4,000	4,000	4,000	4,000
MDQ_BND	3,122	3,122	3,122	3,122
MDQ_LH	21,596	21,596	21,596	21,596
MDQ_STG	28,115	28,115	28,115	28,115
MSQ_STG	2,586,580	2,586,580	2,586,580	2,586,580
MDQ_Z6	20,000	20,000	20,000	20,000
MDQ_Sem	8,000	8,000	8,000	8,000
MSQ_Sem	1,208,000	1,208,000	1,208,000	1,208,000
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	34,600	34,600	34,600	34,600
MDQ_AES	15,000	15,000	15,000	15,000
MSQ_AES	450,000	450,000	450,000	450,000
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	16,475	16,475	23,959	23,959
MDQ_Spot	0	0	0	0
Design Day Requirement	150,908	150,908	158,392	158,392

(*) MDQ of Spot exceeds design day requirement, but is the MDQ required during the design year.

Table 2(b) below shows the 11 demand/price scenarios, with the full 30,000 dth/day MDQ of the Concord Lateral available and in place of the two 'high-priced' spot scenarios.

Table 2b

Summary of Least-cost MDQ and MSQ for Key GLPK Variables

Variable	HighCase 55 2009/10	HighCase 75 2009/10	HighCase 55 2011/12	HighCase 75 2011/12
MDQ_ANE	4,000	4,000	4,000	4,000
MDQ_BND	3,122	3,122	3,122	3,122
MDQ_LH	21,596	21,596	21,596	21,596
MDQ_STG	28,115	28,115	28,115	28,115
MSQ_STG	2,586,580	2,586,580	2,586,580	2,586,580
MDQ_Z6	20,000	20,000	20,000	20,000
MDQ_Sem	8,000	8,000	8,000	8,000
MSQ_Sem	1,208,000	1,208,000	1,208,000	1,208,000
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	34,600	34,600	34,600	34,600
MDQ_AES	15,000	15,000	15,000	15,000
MSQ_AES	450,000	450,000	450,000	450,000
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	16,475	16,475	23,959	23,959
MDQ_Spot	0	0	0	0
Design Day Requirement	150,908	150,908	158,392	158,392

Variable	RefCase 65 2007/08	RefCase 65 2009/10	*CL-30000 65 2009/10*		RefCase 65 2011/12	*CL-30000 65 2011/12*
MDQ_ANE	4,000	4,000	*4,000*		4,000	*4,000*
MDQ_BND	3,122	3,122	*3,122*		3,122	*3,122*
MDQ_LH	21,596	21,596	*21,596*		21,596	*21,596*
MDQ_STG	28,115	28,115	*28,115*		28,115	*28,115*
MSQ_STG	2,586,580	2,586,580	*2,586,580*		2,586,580	*2,586,580*
MDQ_Z6	20,000	20,000	*20,000*		20,000	*20,000*
MDQ_Sem	8,000	8,000	*8,000*		8,000	*8,000*
MSQ_Sem	1,208,000	1,208,000	*1,208,000*		1,208,000	*1,208,000*
MDQ_L0	8,266	0	*0*		0	*0*
MSQ_L0	26,942	0	*0*		0	*0*
MDQ_C3	34,600	34,600	*33,575*	(*)	34,600	*33,957*
MDQ_AES	15,000	15,000	*3,558*		15,000	*9,602*
MSQ_AES	450,000	450,000	*106,740*		450,000	*288,060*
MDQ_L1	0	0	*0*		0	*0*
MSQ_L1	0	0	*0*		0	*0*
MDQ_L2	0	0	*0*		0	*0*
MSQ_L2	0	0	*0*		0	*0*
MDQ_C3N	0	0	*0*		0	*0*
MSQ_C3N	0	0	*0*		0	*0*
MDQ_CL	0	16,475	*30,000*		23,959	*30,000*
MDQ_Spot	0	0	*0*		0	*0*
Design Day Requirement	142,699	150,908	*150,908*		158,392	*158,392*

Variable	LowCase 55 2009/10	LowCase 75 2009/10	LowCase 55 2011/12	LowCase 75 2011/12
MDQ_ANE	4,000	4,000	4,000	4,000
MDQ_BND	3,122	3,122	3,122	3,122
MDQ_LH	21,596	21,596	21,596	21,596
MDQ_STG	28,115	28,115	28,115	28,115
MSQ_STG	2,586,580	2,586,580	2,586,580	2,586,580
MDQ_Z6	20,000	20,000	20,000	20,000
MDQ_Sem	8,000	8,000	8,000	8,000
MSQ_Sem	1,208,000	1,208,000	1,208,000	1,208,000
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	34,600	34,600	34,600	34,600
MDQ_AES	15,000	15,000	15,000	15,000
MSQ_AES	450,000	450,000	450,000	450,000
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	16,475	16,475	23,959	23,959
MDQ_Spot	0	0	0	0
Design Day Requirement	150,908	150,908	158,392	158,392

(*) MDQ of C3 (propane) exceeds design day requirement, but is the MDQ required during the design year.

Table 3(a) shows the relative importance of each of the supplies from Table 2(a) in terms of, if one could contract for one additional dth/day of capacity, how much one could further reduce the cost of the overall portfolio.

Table 3a
Summary of Diagnostics for Key GLPK Variables

Variable	HighCase 55 2009/10	HighCase 75 2009/10	HighCase 55 2011/12	HighCase 75 2011/12
MDQ_ANE	-312	-312	-319	-319
MDQ_BND	-521	-521	-528	-528
MDQ_LH	-366	-366	-372	-372
MDQ_STG	-403	-403	-401	-401
MSQ_STG	0	0	0	0
MDQ_Z6	-138	-138	-138	-138
MDQ_Sem	-185	-185	-185	-185
MSQ_Sem	0	0	0	0
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	-72	-68	-100	-86
MDQ_AES	-84	-84	-105	-105
MSQ_AES	0	0	0	0
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	6	0
MDQ_CL	0	0	0	0
MDQ_Spot				

Variable	RefCase 65 2007/08	RefCase 65 2009/10	*Spot 65 2009/10*	RefCase 65 2011/12	*Spot 65 2011/12*
MDQ_ANE	-688	-312	*-1,231*	-319	*-1,264*
MDQ_BND	-897	-521	*-1,440*	-528	*-1,473*
MDQ_LH	-741	-366	*-1,284*	-372	*-1,318*
MDQ_STG	-722	-386	*-1,050*	-381	*-1,065*
MSQ_STG	0	0	*0*	0	*0*
MDQ_Z6	-520	-138	*-1,039*	-138	*-1,069*
MDQ_Sem	-567	-185	*-1,086*	-185	*-1,116*
MSQ_Sem	0	0	*0*	0	*0*
MDQ_L0	0	0	*0*	0	*0*
MSQ_L0	0	0	*0*	0	*0*
MDQ_C3	-105	-81	*-3*	-108	*0*
MDQ_AES	-361	-90	*-413*	-110	*-418*
MSQ_AES	0	0	*0*	0	*0*
MDQ_L1		0		0	
MSQ_L1		0		0	
MDQ_L2		0		0	
MSQ_L2		0		0	
MDQ_C3N		0		0	
MSQ_C3N		0		0	
MDQ_CL		0		0	
MDQ_Spot			*0*		*0*

Variable	LowCase 55 2009/10	LowCase 75 2009/10	LowCase 55 2011/12	LowCase 75 2011/12
MDQ_ANE	-312	-312	-319	-319
MDQ_BND	-521	-521	-528	-528
MDQ_LH	-366	-366	-372	-372
MDQ_STG	-368	-368	-358	-358
MSQ_STG	0	0	0	0
MDQ_Z6	-138	-138	-138	-138
MDQ_Sem	-185	-185	-185	-185
MSQ_Sem	0	0	0	0
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	-90	-90	-116	-116
MDQ_AES	-97	-97	-116	-116
MSQ_AES	0	0	0	0
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	0	0	0	0
MDQ_Spot				

(shaded) = Supply unavailable in this scenario.

Table 3(b) shows the relative importance of each of the supplies from Table 2(b) in terms of, if one could contract for one additional dth/day of capacity, how much one could further reduce the cost of the overall portfolio.

Table 3b
Summary of Diagnostics for Key GLPK Variables

Variable	HighCase 55 2009/10	HighCase 75 2009/10	HighCase 55 2011/12	HighCase 75 2011/12
MDQ_ANE	-312	-312	-319	-319
MDQ_BND	-521	-521	-528	-528
MDQ_LH	-366	-366	-372	-372
MDQ_STG	-403	-403	-401	-401
MSQ_STG	0	0	0	0
MDQ_Z6	-138	-138	-138	-138
MDQ_Sem	-185	-185	-185	-185
MSQ_Sem	0	0	0	0
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	-72	-68	-100	-86
MDQ_AES	-84	-84	-105	-105
MSQ_AES	0	0	0	0
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	6	0
MDQ_CL	0	0	0	0
MDQ_Spot				

Variable	RefCase 65 2007/08	RefCase 65 2009/10	*CL-30000 65 2009/10*	RefCase 65 2011/12	*CL-30000 65 2011/12*
MDQ_ANE	-688	-312	*-179*	-319	*-187*
MDQ_BND	-897	-521	*-388*	-528	*-396*
MDQ_LH	-741	-366	*-232*	-372	*-240*
MDQ_STG	-722	-386	*-263*	-381	*-254*
MSQ_STG	0	0	*0*	0	*0*
MDQ_Z6	-520	-138	*-4*	-138	*-6*
MDQ_Sem	-567	-185	*-51*	-185	*-53*
MSQ_Sem	0	0	*0*	0	*0*
MDQ_L0	0	0	*0*	0	*0*
MSQ_L0	0	0	*0*	0	*0*
MDQ_C3	-105	-81	*0*	-108	*0*
MDQ_AES	-361	-90	*0*	-110	*0*
MSQ_AES	0	0	*0*	0	*0*
MDQ_L1		0		0	
MSQ_L1		0		0	
MDQ_L2		0		0	
MSQ_L2		0		0	
MDQ_C3N		0		0	
MSQ_C3N		0		0	
MDQ_CL		0	*0*	0	*0*
MDQ_Spot					

Variable	LowCase 55 2009/10	LowCase 75 2009/10	LowCase 55 2011/12	LowCase 75 2011/12
MDQ_ANE	-312	-312	-319	-319
MDQ_BND	-521	-521	-528	-528
MDQ_LH	-366	-366	-372	-372
MDQ_STG	-368	-368	-358	-358
MSQ_STG	0	0	0	0
MDQ_Z6	-138	-138	-138	-138
MDQ_Sem	-185	-185	-185	-185
MSQ_Sem	0	0	0	0
MDQ_L0	0	0	0	0
MSQ_L0	0	0	0	0
MDQ_C3	-90	-90	-116	-116
MDQ_AES	-97	-97	-116	-116
MSQ_AES	0	0	0	0
MDQ_L1	0	0	0	0
MSQ_L1	0	0	0	0
MDQ_L2	0	0	0	0
MSQ_L2	0	0	0	0
MDQ_C3N	0	0	0	0
MSQ_C3N	0	0	0	0
MDQ_CL	0	0	0	0
MDQ_Spot				

= Supply unavailable in this scenario.

Table 4(a) portrays quantitatively the utilization rate that develops when only the 'high-priced' spot gas resource is available. In this case, the LP Model makes every effort to maximize the use of the existing ENGI resource portfolio and minimize the incremental spot gas resource.

Table 4a
COMPARISON OF RESOURCES AND REQUIREMENTS
(MMBtu)

		Design Year 2007-08: GLPK Reference Case; 65				Design Year 2009-10: GLPK Spot Reference Case; 65				Differences			
REQUIREMENTS		Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day
Firm Sendout		10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209
Refill	Underground Storage	0	0	0	0	0	0	0	0	0	0	0	0
	LNG	0	0	0	0	0	0	0	0	0	0	0	0
	Propane	0	0	0	0	0	0	0	0	0	0	0	0
Total Requirements		10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209
RESOURCES													
PNGTS		0	0	0	0	0	0	0	0	0	0	0	0
TGP	AES-Londonderry	407,276	0	407,276	15,000	450,000	0	450,000	15,000	42,724	0	42,724	0
	Dawn Supplies	604,000	856,000	1,460,000	4,000	604,000	856,000	1,460,000	4,000	0	0	0	0
	BP (Niagara)	469,145	668,108	1,137,253	3,122	471,422	668,108	1,139,530	3,122	2,277	0	2,277	0
	Dracut DJF	1,777,862	0	1,777,862	20,000	1,799,193	0	1,799,193	20,000	21,331	0	21,331	0
	Gulf Supply	3,138,289	1,967,143	5,105,432	21,596	3,256,573	1,895,664	5,152,237	21,596	118,284	-71,479	46,805	0
	Market Area – Zone 4	0	0	0	0	0	0	0	0	0	0	0	0
	Market Area – Zone 6	562,127	419,293	981,420	0	764,282	799,244	1,563,527	0	202,155	379,951	582,107	0
	Storage	2,586,580	0	2,586,580	28,115	2,584,730	1,850	2,586,580	28,115	-1,850	1,850	0	0
New LNG w/o liquefaction		0	0	0	0	0	0	0	0	0	0	0	0
New LNG w/ liquefaction		0	0	0	0	0	0	0	0	0	0	0	0
New Propane		0	0	0	0	0	0	0	0	0	0	0	0
Concord Lateral		0	0	0	0	0	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	214,880	0	214,880	16,602	214,880	0	214,880	16,602
Sempra	Vapor	975,023	232,977	1,208,000	8,000	1,027,252	180,748	1,208,000	8,000	52,229	-52,229	0	0
DOMAC	Liquid	0	0	0	0	0	0	0	0	0	0	0	0
LNG From Storage		26,942	0	26,942	8,266	0	0	0	0	-26,942	0	-26,942	-8,266
Propane	Vapor	154,169	0	154,169	34,600	154,169	0	154,169	34,473	0	0	0	-127
	Truck	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources		10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209

		Design Year 2011-12: GLPK Spot Reference Case; 65				Differences			
REQUIREMENTS		Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day
Firm Sendout		11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693
Refill	Underground Storage	0	0	0	0	0	0	0	0
	LNG	0	0	0	0	0	0	0	0
	Propane	0	0	0	0	0	0	0	0
Total Requirements		11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693
RESOURCES									
PNGTS		0	0	0	0	0	0	0	0
TGP	AES-Londonderry	450,000	0	450,000	15,000	42,724	0	42,724	0
	Dawn Supplies	604,000	856,000	1,460,000	4,000	0	0	0	0
	BP (Niagara)	471,422	668,108	1,139,530	3,122	2,277	0	2,277	0
	Dracut DJF	1,800,000	0	1,800,000	20,000	22,138	0	22,138	0
	Gulf Supply	3,259,033	1,922,338	5,181,371	21,596	120,744	-44,805	75,939	0
	Market Area – Zone 4	0	0	0	0	0	0	0	0
	Market Area – Zone 6	1,081,460	1,014,564	2,096,024	0	519,333	595,271	1,114,604	0
	Storage	2,580,753	5,827	2,586,580	28,115	-5,827	5,827	0	0
New LNG w/o liquefaction		0	0	0	0	0	0	0	0
New LNG w/ liquefaction		0	0	0	0	0	0	0	0
New Propane		0	0	0	0	0	0	0	0
Concord Lateral		0	0	0	0	0	0	0	0
Other Purchased Resources		447,511	0	447,511	37,024	447,511	0	447,511	37,024
Sempra	Vapor	1,045,049	162,951	1,208,000	8,000	70,026	-70,026	0	0
DOMAC	Liquid	0	0	0	0	0	0	0	0
LNG From Storage		0	0	0	0	-26,942	0	-26,942	-8,266
Propane	Vapor	154,169	0	154,169	21,535	0	0	0	-13,065
	Truck	0	0	0	0	0	0	0	0
Total Resources		11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693

Table 4(b) portrays quantitatively the utilization rate that develops when the least-cost alternative resource (the Concord Lateral) is available. The utilization rate is much higher than that of the spot gas scenarios because the Tennessee capacity can be used to displace other more expensive resources in the Company's portfolio and reduce the portfolio cost below the level possible under the spot-gas scenario.

Table 4b
COMPARISON OF RESOURCES AND REQUIREMENTS
(MMBtu)

	Design Year 2007-08: GLPK Reference Case; 65				Design Year 2009-10: GLPK CL-30000 Reference Case; 65				Differences			
REQUIREMENTS	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day
Firm Sendout	10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209
Refill Underground Storage	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	0	0	0	0	0	0	0
Propane	0	0	0	0	0	0	0	0	0	0	0	0
Total Requirements	10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209
RESOURCES												
PNGTS	0	0	0	0	0	0	0	0	0	0	0	0
TGP AES-Londonderry	407,276	0	407,276	15,000	24,416	0	24,416	3,558	-382,860	0	-382,860	-11,442
Dawn Supplies	604,000	856,000	1,460,000	4,000	604,000	856,000	1,460,000	4,000	0	0	0	0
BP (Niagara)	469,145	668,108	1,137,253	3,122	470,873	668,108	1,138,981	3,122	1,728	0	1,728	0
Dracut DJF	1,777,862	0	1,777,862	20,000	546,999	0	546,999	20,000	-1,230,863	0	-1,230,863	0
Gulf Supply	3,138,289	1,967,143	5,105,432	21,596	3,168,161	1,973,508	5,141,669	21,596	29,872	6,365	36,237	0
Market Area – Zone 4	0	0	0	0	0	0	0	0	0	0	0	0
Market Area -- Zone 6	562,127	419,293	981,420	0	23,766	0	23,766	0	-538,361	-419,293	-957,654	0
Storage	2,586,580	0	2,586,580	28,115	2,586,580	0	2,586,580	28,115	0	0	0	0
New LNG w/o liquefaction	0	0	0	0	0	0	0	0	0	0	0	0
New LNG w/ liquefaction	0	0	0	0	0	0	0	0	0	0	0	0
New Propane	0	0	0	0	0	0	0	0	0	0	0	0
Concord Lateral	0	0	0	0	2,869,898	573,638	3,443,536	30,000	2,869,898	573,638	3,443,536	30,000
Other Purchased Resources	0	0	0	0	0	0	0	0	0	0	0	0
Sempra Vapor	975,023	232,977	1,208,000	8,000	877,639	330,361	1,208,000	8,000	-97,384	97,384	0	0
DOMAC Liquid	0	0	0	0	0	0	0	0	0	0	0	0
LNG From Storage	26,942	0	26,942	8,266	0	0	0	0	-26,942	0	-26,942	-8,266
Propane Vapor	154,169	0	154,169	34,600	154,169	0	154,169	32,517	0	0	0	-2,083
Truck	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	10,701,413	4,143,521	14,844,934	142,699	11,326,501	4,401,615	15,728,116	150,908	625,088	258,094	883,182	8,209

	Design Year 2011-12: GLPK CL-30000 Reference Case; 65				Differences			
REQUIREMENTS	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	TOTAL	Peak Day
Firm Sendout	11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693
Refill Underground Storage	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	0	0	0
Propane	0	0	0	0	0	0	0	0
Total Requirements	11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693
RESOURCES								
PNGTS	0	0	0	0	0	0	0	0
TGP AES-Londonderry	76,166	0	76,166	9,602	-331,110	0	-331,110	-5,398
Dawn Supplies	604,000	856,000	1,460,000	4,000	0	0	0	0
BP (Niagara)	471,422	668,108	1,139,530	3,122	2,277	0	2,277	0
Dracut DJF	696,904	0	696,904	20,000	-1,080,958	0	-1,080,958	0
Gulf Supply	3,187,173	1,988,811	5,175,984	21,596	48,884	21,668	70,552	0
Market Area – Zone 4	0	0	0	0	0	0	0	0
Market Area -- Zone 6	51,678	0	51,678	0	-510,449	-419,293	-929,742	0
Storage	2,586,580	0	2,586,580	28,115	0	0	0	0
New LNG w/o liquefaction	0	0	0	0	0	0	0	0
New LNG w/ liquefaction	0	0	0	0	0	0	0	0
New Propane	0	0	0	0	0	0	0	0
Concord Lateral	3,150,188	823,986	3,974,174	30,000	3,150,188	823,986	3,974,174	30,000
Other Purchased Resources	0	0	0	0	0	0	0	0
Sempra Vapor	915,117	292,883	1,208,000	8,000	-59,906	59,906	0	0
DOMAC Liquid	0	0	0	0	0	0	0	0
LNG From Storage	0	0	0	0	-26,942	0	-26,942	-8,266
Propane Vapor	154,169	0	154,169	33,957	0	0	0	-643
Truck	0	0	0	0	0	0	0	0
Total Resources	11,893,397	4,629,788	16,523,185	158,392	1,191,984	486,267	1,678,251	15,693