Final Report

Review of Supply Planning and Asset Management Agreements of EnergyNorth Natural Gas, Inc.

Presented to the:

New Hampshire Public Utilities Commission

By:

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I. Introduction

In June, 2004, the New Hampshire Public Utilities Commission (*NH PUC*, or *the Commission)* issued a request for proposals (*RFP*) to assist the Commission's Staff in evaluating the demand forecasting and gas-supply planning of EnergyNorth Natural Gas, Inc. (*ENGI* or *the Company*), d/b/a KeySpan Energy Delivery New England (*KEDNE*). The need for an evaluation grew out of a dispute between the Staff and the Company regarding gas dispatch for the winter of 2002/03. That dispute, and the associated question of a Gas Resource Portfolio Management and Gas Sales Agreement between EnergyNorth Natural Gas, Inc. as Buyer and Entergy-Koch Trading, LP as Seller (the *asset management agreement* or *AMA*), entered into by the Company in the fall of 2002, have affected all of the Company's cost-of-gas (*COG*) proceedings since a settlement, entered into by the Company and the Staff in March, 2004, and approved by the Commission in May, 2004.[1] That settlement resolved the question of the Company's Winter 2002/03 gas costs, but left the questions of ENGI's gas dispatch and its utilization of its AMA for further discussion.

The Commission's RFP sought a consultant to evaluate the statistical modeling and resource planning methodologies employed by ENGI for daily dispatch and for long-term planning. In particular, the consultant was to

1. Evaluate the specific models that are used to forecast market requirements, pipeline capacity, peak-shaving resources and dispatch, supply costing and economic dispatch;
2. Evaluate whether ENGI has developed and utilized an appropriate and comprehensive resource model in its short- and long-term resource planning;
3. Assess whether ENGI has demonstrated its ability to effectively manage its supply portfolio with the demands placed on it by its customers and available supply resources; and
4. Perform a limited analysis of ENGI's demand forecasting to assess its reasonableness.

The RFP envisioned three reports from the consultant:

1. Report on a review of ENGI's supply planning models used in preparing its COG filings and assess if they are consistent with least-cost supply planning and provide a reasonable basis on which to determine COG rates.
2. Report on a review of ENGI's filed Integrated Resource Plan (*IRP*) and consider whether the Company's demand forecasting is reasonable, and whether its long-term supply planning is appropriate and consistent with least-cost planning.
3. Perform a cost/benefit analysis to date of the Company's AMA to assess whether the AMA will provide a net benefit over its term, how it might be restructured to provide greater benefits to ENGI's customers, and whether the existing or a similarly-structured AMA should be employed beyond the current term of the agreement.

[1] Order No. 24,323, Order Approving Settlement Agreement, in Docket No. DG 03-160, EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England, 2003-2004 Winter Cost of Gas.

The Liberty Consulting Group (*Liberty*) was retained by the Commission to conduct this work. Liberty initially assisted the Staff with its review of the Company's Winter 2004-2005 Winter Cost of Gas filing, and then conducted the review envisioned by the RFP.

This document is Liberty's report on our review. This report addresses all three areas covered by the RFP, namely long-term planning, short-term planning and the Company's AMA. The report draws on materials submitted by the Company in this proceeding -- the combined proceeding covering the Company's IRP filing (Docket No. DG 04-133) and the Staff's investigation of the prudence of the Company's dispatch during the winter of 2003-2004 (Docket No. DG 04-175) -- but also on materials submitted in Docket No. DG 04-152 (2004-2005 Winter Cost of Gas), Docket No. DG 04-040 (2004 Summer Cost of Gas) and Docket No. 03-160 (2003-2004 Winter Cost of Gas). The Liberty team participated in technical sessions convened to discuss the Company's 2004-2005 Winter Cost of Gas filing, and to discuss the Company's IRP. The team also traveled to the Company's offices in Waltham, MA to conduct interviews. The Liberty team presented testimony to the Commission in this proceeding, and in the 2004-2005 Winter Cost of Gas proceeding.

Chapter II of this report considers the Company's long-term planning, and presents our review of the Company's IRP. Chapter III considers short-term planning, including dispatch and balancing. Chapter IV considers the Company's AMA. Conclusions and recommendations pertaining to each of those subjects are presented at the end of the respective chapters.

Because of the Company's concerns about the scope of the review to be conducted in this docket, there were several instances where areas that might normally warrant further investigation were not pursued. We have noted those instances in the body of this report. In the last chapter of the report, we present our recommendations for further, more detailed investigations.

II. Long-Term Gas Supply Planning (the IRP)

A. Background

ENGI filed Least Cost Integrated Resource Plans (IRPs) with the Commission prior to its acquisition by KeySpan. The last one was filed in 1998. Following a review of that filing, the Commission decided to discontinue the formal filing of IRPs, apparently based on the assumption that the issues normally evaluated in a utility's IRP filing could be adequately addressed in cost-of-gas (COG) proceedings.

As noted earlier, the Staff and the Company had a major disagreement over the Company's dispatch of its gas supplies during the winter of 2002-2003. During that period, the cost associated with the bulk of ENGI's gas supply portfolio was determined by the existence of tier-structured pricing established in the Company's AMA with Entergy-Koch Trading, LP (*EKT*). A settlement was entered in that particular proceeding, but the issue of appropriate dispatch for future periods was left for future discussion and resolution, as was discussion of possible changes in the AMA. As part of that settlement, the Company agreed to prepare and file a new IRP. The Company filed its IRP on August 2, 2004 as contemplated by the settlement.

B. Summary of Liberty Activities

Liberty began to familiarize ourselves with ENGI's supply resources and markets by assisting the Staff with its review of the Company's COG filing for the winter of 2004-2005 (Docket No. DG 04-152). Liberty personnel conducted an initial, cursory review of the IRP filing, but then put it aside in order to focus on the COG proceeding. For that proceeding, we assisted the Staff with the preparation of data requests, participated in technical sessions, and presented brief testimony to the Commission, to inform the Commission about the nature of our work, and to advise it about the link between gas supply planning and the cost of gas experienced by the Company's customers.

After the completion of the COG proceeding, Liberty resumed our review of the IRP filing. We prepared data requests, and participated in several technical sessions, held to discuss the Company's filing and its responses to our data requests. In January, 2005, Liberty briefed the Staff on the results of our review of the IRP and the other matters at issue in this proceeding (dispatch and the AMA). We prepared testimony for submission in this proceeding, and we responded to data requests from the Company regarding our testimony. We also participated in a technical session to discuss with the Company our testimony and our responses to the Company's data requests.

C. Analysis/Findings

The 2004 IRP presents a five-year forecast of customer requirements under design weather conditions, and then compares those requirements to the supply resources in its current portfolio to see whether incremental resources will be necessary to meet forecast requirements. The IRP also presents a "cold-snap" analysis, to test the portfolio's performance under the weather actually experienced in the seven-day period from January 9, 2004, through January 15, 2004. Finally, the IRP presents an analysis of the Commission's Seven-Day Storage requirement: PUC Rule 506.03, that requires New Hampshire gas utilities to maintain an on-site storage capability in connection with operation of their gas distribution systems sufficient to provide peak-shaving supplies for a maximum-design cold period of seven consecutive days.

Liberty evaluated the Company's design-weather forecast, and then reviewed its portfolio assessment and the two supplemental evaluations (the cold-snap analysis and the seven-day rule). Discussion of our findings follows.

1. The Five-Year Forecast of Customer Requirements

The Company reports that it uses a five-step process to estimate customer requirements under design-weather conditions. Those five steps are as follows:

1. Forecast incremental sendout
2. Develop reference year sendout using regression equations
3. Normalize forecast of customer requirements
4. Determine design weather planning standards
5. Determine customer requirements under design weather conditions.

Each of those steps is discussed in turn.

Step 1: Forecast Incremental Sendout

The Company uses an end-use demand model to forecast annual incremental growth in its traditional markets over the period of interest (November 1, 2004 through October 31, 2009 for this IRP). The Company then adds specific requirements for non-traditional markets, such as natural gas vehicles and large-scale cogeneration projects, and subtracts amounts for demand-side management savings. Finally, the resulting incremental demand forecasts are added to normalized sendout information from a base year (May, 2003 through April, 2004 in this case).

The Company advised[i] us that because of the limited time frame in which the IRP needed to be prepared, the Company did not have an opportunity to update certain data used in its end-use model. The model is based, in part at least, on a home energy-use survey conducted for Boston Gas Company in 1998. Boston Gas had the entire model updated in late 1999[2], but some of the data used in the update extends back to 1993[3]. Furthermore, the data and the end-use model may not be reflective of New Hampshire customers. The Company's next IRP should include more current data, to the extent feasible, and the Staff and the Company should discuss whether more New Hampshire-specific data is available and would be useful.

[2] Reports on the home energy use survey and the model update are presented as Appendices B and A, respectively, to the Company's August 2, 2004 filing.
[3] See, *e.g.*, the sections entitled "Residential New Construction Adjustment Factors" and "Commercial New Construction Adjustment Factors", at pp. 55-57 of Appendix A to the IRP.

Liberty tested some of ENGI's customer data to see whether we could find evidence of changes in use characteristics since the mid-1990s. As we understand it, the Company's end-use model forecasts increases in the number of customers, and then multiplies that increase by use per customer to get a forecast of incremental demand.[4] The use-per-customer information is based on the energy-use surveys that were done in Massachusetts, and date from the mid-1990s.

Use per customer in fact changes over time due to changes in equipment type and age in each end use (space heating, water heating, etc). Change also occurs due to the mixture of old and new housing, equipment replacement rates, and other factors.

The test we ran was to see whether we could see a change in use per customer by analyzing ENGI billing data. Liberty developed estimates of use per customer for a single residential rate class (R3)[5] for two time periods (1990 to 2000 and 1995 to 2004), and looked to see whether the trends in that data changed between the two periods.

Indeed, the trends did change. A definite decline in use per customer in the earlier time period had largely disappeared in the later time period. (This is not an unreasonable result, as LDCs around the country have been noticing a slowing of the decline in use per customer as houses get bigger, customers install more gas appliances, customers set their thermostats higher, etc.) Details of our analysis are presented in Appendix I to this chapter. The important point is that use per customer is not a static parameter, and it must be updated periodically in order to capture changes in the Company's load.[6]

Because structural models require frequent updating of large amounts of data, Liberty prefers forecasts based on econometric analysis of billing and sendout data. Liberty's preference is for regression of use-per-customer data (*i.e.*, daily sendout divided by number of customers) against weather to determine base and use factors for each rate class, and then multiplying those factors by the forecasted number of customers in that rate class. The forecasted number of customers is developed with a separate regression for the number of customers in each rate class using a trend variable and appropriate dummy variables, and is adjusted for expected increases or decreases in the number of customers. This is, in fact, similar to how the Company estimates normalized sendout for its base, or "springboard", year,[7] which is discussed next.

[4] See charts III-B-1, III-B-2, III-B-3, III-B-4.
[5] This rate class accounted for 44 percent of ENGI's load in February, 2004.
[6] In comments on a draft of this report, the Company reported that it updates this data annually. The Company also reported that, more recently, as gas prices have increased, use per customer has resumed its prior declining pattern.

[7] The Company's equation includes lagged EDDs and a weekend dummy variable, both of which are important in forecasting daily or design-day sendout. They are not material in forecasting monthly or annual sendout, however, since they tend to 'wash out' in the process of forecasting 30 or more days. The Company includes these variables since the same equation is used to forecast both design-day and annual sendout. The Company's equation for the springboard year does not contain a trend variable because it uses only one year of data.

Step 2: The "Springboard" Year

The Company reports that it uses regression equations of daily sendout versus daily temperature for the most recent 12 months to calculate the reference-year "springboard". For this IRP, it used data for May 1, 2003 through April 30, 2004. Actual daily firm sendout was regressed against the daily effective degree day (EDD) data provided by the Company's weather services provider, Meteorologix. Data from the Manchester, New Hampshire weather station was used as the principal explanatory variable. The regression analysis is used to adjust the actual sendout information for the reference year to normal weather.

Liberty's only issue with this part of the Company's method is its use of only one year's data (sendout and weather) to calculate the base and use factors. In our experience, base and use factors can vary for the same load if the weather is warmer than normal or colder than normal. The change that we would recommend is to develop use-per-customer estimates based on an average of the past three to five years, rather than just one.

Step 3: Normalized Forecast of Customer Requirements

In the third step of the Company's forecasting method, the Company combined the May, 2003 to April, 2004 reference year sendout, adjusted to normal weather, with the annual incremental sendout forecast from the end-use model. Liberty tested the Company's results against forecasts that we developed using the econometric methods that we prefer. Liberty regressed the data marked "Sendout for Customers Using Utility Capacity", provided in the Company's response to DR No. 1-1 in Docket No. DG 04-152, against the EDD data provided in the Company's response to DR No. 1-5 in DG 04-152, using an equation that allows for base and use factors that vary by month. The tables below show how our results compare with the Company's.

Table II-1
Customer Requirements, Base Case Demand Scenario, Normal-Year Weather
(MMBtu)

	2004-05	2005-06	2006-07	2007-08	2008-09
ENGI results	13,207,200	13,631,100	14,006,900	14,389,700	14,608,000
Liberty results	13,444,648	13,948,332	14,452,016	14,955,700	15,459,384
Difference, %	1.77%	2.27%	3.08%	3.78%	5.51%

Sources: ENGI results, Chart III-A-1; Liberty results computed as described.

While Liberty's estimates rely on a single sendout regression, they also incorporate a trend variable, developed from data from May 1, 2000 through April 30, 2004. This trend variable acts as a 'catch-all' for customer growth (since the single equation does not explicitly account for customer growth) and changes in use per customer over time. Liberty's recommendation for forecasting annual sendout is to derive the monthly number of customers and monthly usage per customer for each rate class from monthly billing data, and to generate two econometric regressions for each rate class: one for the number of customers and one for the use per customer. When the number of customers and average use per customer for a customer class are highly predictable based on historical trends, econometric regressions yield tight fits and constitute an easy method for demand forecasting.

It is Liberty's opinion that the use of a "structural" or end-use-based model, such as that used by the Company, is appropriate for certain customer classes where demand does not correlate well with weather data. Similarly, the demand forecasting methodology should be able to explicitly account for known changes identified through market intelligence (such as the addition of large customers, or expected changes in transportation migration) regarding demand trends. ENGI should also track the performance of its marketing department's predictions of additional customers and demand, and incorporate those predictions into the demand forecasting process as appropriate.

Notice that Liberty's requirements forecasts are higher than the Company's, and that the difference increases over time. A possible explanation for this difference is the change in the trend of use per customer mentioned earlier: the declining trend observed in the 1990-2000 use-per-customer regression (*i.e.*, declining use per customer) is replaced by a statistically-insignificant trend (*i.e.*, flat use per customer) in the 1995-2004 regression. The difference between the two models might be eliminated if ENGI has an opportunity to update its model using more current data.

Step 4: Determine Design Weather Planning Standards

The Company uses a cost/benefit analysis to develop its design-day and design-year supply planning criteria. The general idea is that the appropriate criterion is the point where the cost of incremental supply just equals the benefit of avoiding curtailment.

For the design-day criterion, the costs of incremental supply and the benefits of avoiding curtailment are developed as ranges. On the curtailment side, the range is developed by applying a range in the proportion of residential customers whose homes would be damaged by the curtailment: a low proportion damaged yields a relatively low benefit of avoiding curtailment, and a high proportion damaged yields a relatively high benefit of avoiding curtailment. The range in the cost of incremental supply is developed by considering a low-cost supply option – add propane vaporization capacity – and a high-cost supply option – add 365-day interstate pipeline capacity.

The Company's analysis superimposes the two ranges and finds that they intersect at a range of design-day values, from 77 to 84 enhanced degree-days (EDD). From this range, the Company picked 79.7 EDD (rounded to 80) in order to maintain the same probability of occurrence (once in 46.69 years) that the Company uses for its Massachusetts affiliates.

The design-year standard is developed in a similar manner. To establish an estimated total annual level of EDD for which the Company should plan, the Company compared the cost of maintaining an adequate quantity of gas under all reasonable weather conditions, to the probability-weighted benefit of avoiding losses that might occur if supplies are not adequate. The estimate of losses is based on the product of the potential economic cost per day of interruption, times the number of days of interruption. The range in value of the cost of sufficient supply is based on the cost of a winter-service supply contract (low side) and winter-period market-area purchases (high side). Similarly superimposing the two ranges, the Company identified 7,740 to 8,040 EDD as the appropriate range for planning purposes, and selected 7,873 EDD (rounded to 7,870) as its design-year value, again in order to maintain the same probability of occurrence (once in 37.43 years) that KeySpan uses for its Massachusetts companies.

Weather Analysis

Liberty finds this approach to the development of design criteria for supply planning somewhat unusual, although we understand that it is consistent with what is done by LDCs throughout Massachusetts based on requirements imposed by Massachusetts regulators.[ii] We are concerned that when we analyzed the weather data that the Company provided, we obtained values for the probability of occurrence of the Company's design-day and design-year criteria that are different from the Company's. Our analysis is discussed below.

A significant portion of the load for LDCs, and especially the load related to residential customer classes, demonstrates strong correlation with weather. The use of appropriate weather data is therefore critical in determining the forecasted level of demand for different weather scenarios. LDCs typically assess base budgets on what is termed *normal weather*. This term is defined by an average of historically observed heating degree-days (*HDDs*) over a number of years, or of those recorded by an independent authority such as the National Oceanic and Atmospheric Administration (*NOAA*).[8]

HDDs are calculated for each day as the number of degrees by which the average temperature for the day is below 65. In addition to HDDs, wind is usually factored into the forecasting of short-term daily sendout. As noted earlier, for ENGI, KeySpan uses effective degree days (EDDs) reported for Manchester, NH by the Company's weather services provider. Most utilities use total HDDs as a predictor of annual sendout, and HDDs plus wind, lagged-day HDDs and weekday/weekend dummy variables for daily sendout forecasting purposes. For ENGI, KeySpan uses EDDs, which combines the effect of HDDs and wind into one variable designed to allow better prediction of sendout.

In order to compare the prediction power of using EDDs versus HDDs[9] plus wind in forecasting firm sendout, Liberty analyzed a short amount of data for the month of January 2004.[10] The first comparison was done by calculating a correlation coefficient, which is a measure of the extent to which two variables change in the same fashion. A perfect positive correlation is indicated by 1

[8] NOAA normals are calculated on the basis of 30 years.

[9] One significant difference between NOAA HDDs and Meteorologix's EDDs is that HDDs are calculated as the average of the daily minimum and maximum for the calendar day. EDDs are calculated for the 24-hour period of 10 a.m. to 10 a.m., corresponding to the gas day.

[10] Liberty used data available through NOAA's Record of Climatological Observations database, which does not contain data for Manchester, NH after 1999. As a proxy, Liberty used available weather data for Concord Municipal Airport, which is about 20 miles north of Manchester Airport, and closer than that to the City of Manchester. The reason for picking January 2004 for this analysis was that some of the coldest days were observed during that month, including an 80-EDD day, which is equal to ENGI's design-day criterion.

(100%), and a perfect negative correlation is indicated by -1 (-100%). The coefficient between HDDs and firm sendout was 96.05%, compared to 97.91% between EDDs and firm sendout. The same calculation was done with all available common data[11], and the coefficients were 96.45% for HDDs and 97.75% for EDDs. These results indicate a high degree of correlation for both parameters, but that EDDs from Meteorologix are a better predictor of firm sendout than HDDs alone.

A second analysis was done through regressions, focusing on the month of January 2004 and including wind data in the comparison. The R-Squared (R^2) statistic of a regression measures the success of the regression in predicting the values of the dependent variable (in this case, daily firm sendout) within the sample, and is 1 (100%) when the prediction power is 100%. A regression of HDDs plus wind for Concord on firm sendout yielded R^2 = 94.8%, compared to the regression with EDDs where R^2 = 95.9%. A further regression including lagged EDDs yielded R^2 = 98.8%[12]. Liberty therefore concludes that ENGI is deriving additional explanatory power from using EDDs instead of HDDs for load-forecasting purposes.

Distribution of Weather Data

As noted earlier, in order to determine adequate design-weather planning standards, the Company performed weather distribution analysis using daily EDD data from 1981 through 2000 for the Manchester, NH weather station. As a first step, ENGI calculated normal weather as the average annual number of EDDs, and found the data to be normally distributed, with average 7,068 EDD, standard deviation 416.9. The Company then developed a "typical meteorological year" by selecting, for each calendar month, the month among the 20 years of data that most closely matched the average EDD and standard deviation for each month.

Liberty used EDD data provided by the Company for the same 20 years and calculated the average annual number of EDDs, but got different results: The average annual EDD was 7,140, and the standard deviation was 338. The difference in the average annual EDD can be explained by rounding, but Liberty does not know why there is a substantial difference between the standard deviations. Given the resolution of issues in this case reached by the parties, this difference was not explored further.

Liberty calculated the following table using the EDD data provided by ENGI, and augmented the data to provide EDDs for the leap-year days based on an average of the EDDs the day before and day after[13]. Columns 1 through 12 in the table indicate the standard deviation, minimum, average, and maximum monthly EDDs, and the +/- 2 standard-deviation bounds around the average for each calendar month. The last three columns (with the next-to-last column (November – October) corresponding to ENGI's gas planning year) indicate the variation in

[11] Limited by the availability of daily firm sendout data from 5/1/2000 to 4/30/2004 provided in DR No. 1-1 in Docket No. DG 04-152.

[12] The relevant comparison for this result would be an equation with lagged HDDs and wind. However, lagged HDDs turned out to be statistically insignificant in the regression, and the inclusion of lagged wind yielded R^2 = 96.5%.

[13] This is the reason for the difference between 7,140 EDD calculated above and 7,149 EDD for 1981-2000 presented in the table.

annual EDD for the specified year (not the summation of the associated row). Liberty summed the annual EDD for the 20 years and then divided by 20 to determine the annual average number.

Table II-2
Monthly Distribution of EDDs

Effective Degree Days (EDDs) For Manchester, NH													1981-2003	1981-2003	1981-2000
Month:	1	2	3	4	5	6	7	8	9	10	11	12	Jan-Dec	Nov-Oct	Jan-Dec
Std. Dev.	162	113	76	58	49	37	15	22	46	69	74	148	350	384	342
Min	1075	909	834	486	180	40	6	4	77	355	654	912	6450	6316	6450
-2 std	1021	889	822	487	203	20	0	3	96	370	637	847	6420	6360	6465
Avg	1346	1114	973	602	301	94	26	47	188	508	786	1143	7121	7129	7149
+2 std	1671	1339	1125	717	399	169	55	92	279	645	934	1440	7821	7898	7834
Max	1645	1332	1148	702	398	178	62	84	251	640	925	1617	7700	7674	7700

If weather were normally distributed, statistical theory says that the values shown in the rows between the minimum and the maximum should be ordered, with the minimum and maximum very close to the +/- 2 standard deviation figures. This range would correspond to a 95-percent-probability band on the distribution. With about 50 years of available data, a temperature extreme with a probability of 2.5 percent on either side of the distribution would correspond to 50 years times 2.5 percent per year probability, or about one occurrence in 50 years.

The fact that the maximum values observed are sometimes less than the average plus two standard deviations (see January and February), but sometimes more (see March and December), is evidence that the probability distributions of EDDs for each month are not normal ones. Thus, the mean (average) plus two standard deviations does not necessarily include 95 percent of the possible outcomes for weather in ENGI's service territory. The correct way to deal with the "abnormal" distribution would be to use a Monte Carlo simulation to develop a probability distribution for ENGI's weather. A Monte Carlo simulation model can be designed to explicitly account for features such as autocorrelation and heteroskedasticity inherent in HDD or EDD data.

Assuming weather temperature follows a continuous distribution with an infinite range, there is always a probability that a new observation, *i.e.*, total annual temperature, HDDs or EDDs, will fall above or below what has been historically observed. A Monte Carlo model can be used to generate a distribution representative of the full distribution, including the unobserved "tails" – extreme warm- or cold-weather days – that would otherwise be ignored by basing decisions on historical observations alone. Monte Carlo simulation thus allows accurate modeling of the extremes of the distribution. For example, in the case of ENGI, calculating the probability of experiencing extremely cold weather of 80 EDDs or beyond would be of particular interest.

Monte Carlo analysis can be complex and expensive. Thus, smaller utilities rely on weather history and extreme weather actually observed. History and observations are commonly used in planning for both for peak-day and annual sendout, along with the simplifying assumption of a normal distribution, to calculate approximate probabilities. To add explanatory power, LDCs may seek to augment their weather data set.

Liberty analyzed the Company's 23.5 years (1981-2004) of EDD data, rather than the 20 years (1981-2000) used in the 2004 IRP. First, we calculated the frequencies of the highest EDD days. Liberty determined that the EDD data for Manchester, NH contains 18 days with 70 or more EDDs, and 49 days with 65 or more EDDs. January 4, 1981, the coldest day in the data set, experienced an average daily temperature of -12 degrees (77 HDDs), with 78 EDDs. On the other hand, the day with the highest EDDs was January 15, 2004. That day had only 70 HDDs, but 80 EDDs. We understand that January 15, 2004 was the highest firm-sendout day ever for ENGI.

The following table shows the days with 65 EDDs or more.

Table II-3
Highest EDD Days for Manchester, NH
(and Corresponding HDDs for Concord, NH)
(1981-2004)

Highest EDD dates		
EDD Date	EDDs	HDDs
1/15/2004	80	70
1/4/1981	78	77
1/17/1982	77	59
12/25/1983	74	70
1/17/2000	74	65
1/9/2004	74	68
1/14/1988	73	69
2/6/1995	73	66
1/14/2004	73	72
1/15/1994	72	59
1/16/1994	72	67
1/26/1994	72	63
1/11/1981	71	64
1/19/1994	71	67
1/21/2000	71	58
1/21/1984	70	73
2/4/1996	70	65
1/22/2000	70	62
1/11/1982	69	68
1/19/1983	69	65
2/8/1985	69	59
1/14/2000	69	58
1/27/2003	69	57
2/15/2003	69	70
1/10/2004	69	66
1/10/1982	68	62
1/18/1982	68	69
1/21/1985	68	59
1/4/1989	68	59
1/22/2003	68	63
1/8/2004	68	60
1/24/2004	68	64
2/15/1987	67	63
2/6/1993	67	58
1/20/1994	67	63
1/5/1996	67	68
2/14/1987	66	62
12/11/1988	66	58
12/22/1989	66	62
2/5/1995	66	56
1/12/1982	65	66
1/22/1982	65	68
1/14/1986	65	60
12/29/1987	65	54
12/30/1987	65	60
12/23/1989	65	62
2/1/1993	65	56
1/27/2000	65	57
1/18/2003	65	67

These observations can be used to assess the probabilities of occurrence of very cold days, by dividing the number of "coldest" days by the number of years in the data set. The following table shows the resulting probability that an extremely cold day will occur within a given year.

Table II-4
Probability of Extreme EDD Days based on 1981 to 2004 Data

Manchester, NH - Coldest Days Analysis		
Data days	8583	
Data yrs	23.52	
	Count	Prob / Year
Days>=80 EDDs	1	4.25%
Days>=79 EDDs	1	4.25%
Days>=78 EDDs	2	8.51%
Days>=77 EDDs	3	12.76%
Days>=76 EDDs	3	12.76%
Days>=75 EDDs	3	12.76%
Days>=74 EDDs	6	25.52%
Days>=73 EDDs	9	38.27%
Days>=72 EDDs	12	51.03%
Days>=71 EDDs	15	63.79%
Days>=70 EDDs	18	76.55%
Days>=69 EDDs	25	100.00%
Days>=68 EDDs	32	100.00%
Days>=67 EDDs	36	100.00%
Days>=66 EDDs	40	100.00%
Days>=65 EDDs	49	100.00%

Given ENGI's EDD data set, ENGI's design-day standard of 80 EDDs is not a once-in-46.69-years (2.14% probability) occurrence, it is a once-in-23.5-years (4.25% probability) event. The 4.25% probability is within the range that most LDCs use for contingency planning (3 to 5% probability).

In order to extend this analysis and obtain a higher level of confidence that the weather data used by the Company for planning purposes encompasses the range of likely outcomes, ENGI could analyze HDD data from NOAA, as that data is available for more years.[14] Another alternative would be to seek a longer set of EDD data for Manchester. Either of these refinements would yield a higher level of confidence that the weather data that the Company is using for planning purposes encompasses the range of likely outcomes.

In order to provide a sense of what a longer data series might produce, Liberty looked at NOAA temperature data for Concord, NH[15] back to 1921. The data shows one 81 HDD day in 1933, and four days of 77 HDD; hence 81 HDD is a once-in-84-years (1.2% probability) occurrence, and 77 HDD is a four-times-in-84-years (4.8% probability) occurrence. Table II-5 shows the distribution of the coldest days for 1981 to 2004, and for 1921 to 2004. These observations provide some data points in the "tails" of the probability distribution. In the absence of a longer EDD data series, for the purpose of evaluating the distribution of weather extremes and for contingency planning, ENGI could use HDD data for Concord, NH.

[14] This data is available through NOAA's Record of Climatological Observations database, which unfortunately does not contain data for Manchester after 1999. As a proxy, there is weather data back to 1921 available for Concord Municipal Airport, which is about 20 miles north of the Manchester Airport and even closer to the city of Manchester.

[15] Liberty understands that the Company does not prefer NOAA weather data for Concord because Concord is a "cold spot" and may not be representative of temperatures experienced by the majority of ENGI's customers.

Table II-5
Extreme HDD Days for Concord, NH

1/1/81 to 6/30/04		1/1/21 to 6/30/04	
Coldest HDD dates		Coldest HDD dates	
HDD Date	HDDs	HDD Date	HDDs
1/4/1981	77	12/29/1933	81
1/21/1984	73	2/16/1943	77
1/26/1982	72	2/15/1943	77
1/22/1984	72	1/19/1971	77
1/14/2004	72	1/4/1981	77
12/25/1983	70	2/9/1934	76
2/15/2003	70	1/18/1976	76
1/15/2004	70	12/30/1933	75
1/12/1981	70	1/19/1976	75
1/14/1988	69	1/11/1976	75

This kind of analysis would be an improvement over the weather analysis in the IRP. Analysis based on Monte Carlo simulations would be better yet, and should be manageable for a company with KEDNE's resources.

ENGI's Planning Standards

The Company's approach in developing its design-day and design-year planning standards is to start with the current values, and then to reassess them periodically to see whether there is a reason to change. The current values are 80 EDD for the design day, and 7,870 EDD for the design year.

The Design-Day Standard

For the design-day standard, the Company uses a three-step process:

1. Statistical analysis of the coldest days
2. A cost-benefit analysis to evaluate the cost of acquiring additional resources versus the benefit of avoiding curtailment
3. Pick a value for the standard at the point where the incremental cost just equals the incremental benefit.

Each of these steps is addressed in turn.

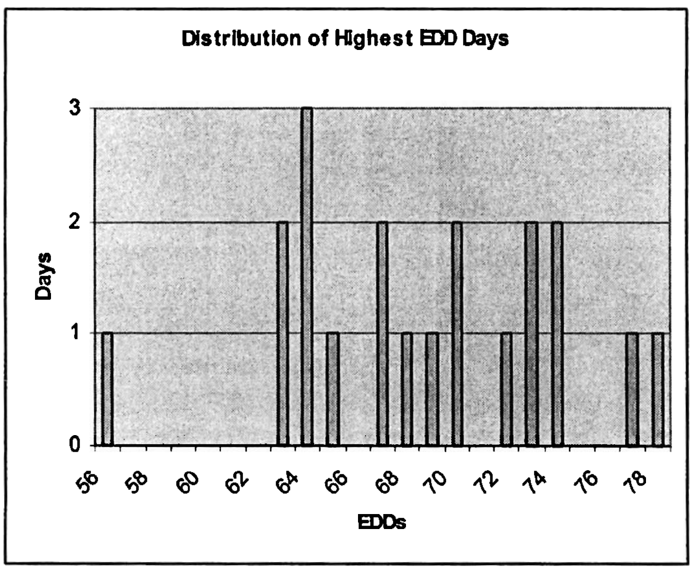
Statistical Analysis of the Coldest Days

In deriving its design-day standard, the Company utilized a statistical analysis of the highest EDD days recorded from January, 1981 through December, 2000.[iii] The Company's IRP stated that the Company found these 20 data points to be normally distributed, with an average of 68.2 EDDs and a standard deviation of 5.7 EDDs, although during a technical session[iv] the Company indicated that it simply had not ruled out a normal distribution. By picking a design-day standard two standard deviations away from the average, ENGI preliminarily selects 68.2+(5.7*2) = 79.6 EDDs, rounded to 80 EDDs, with a probability of occurrence of once in 46.69 years (2.14%).

Liberty repeated the calculation based on the same data,[16] and got an average of 68.6 EDDs with a standard deviation of 5.5 EDDs. Using the same logic that the Company used (average plus two standard deviations) yielded the same design-day standard (79.6 EDD).

The figure below (Figure II-1) presents a frequency distribution of coldest days. The distribution does not look like a normal one, and the low and high extremes are separated from most of the rest of the data, although we are aware that many LDCs use a normal distribution as a simplifying assumption.

Figure II-1
Frequency Distribution of Peak-Day Data, Manchester, NH
(1981-2000)



Cost/Benefit Analysis

The "benefit" for the cost/benefit analysis is the value of avoiding potential curtailments. That value was computed as follows:

- A derived peak-period heating coefficient (1,357 MMBtu/day)[17] was used to convert each incremental EDD to an equivalent number of customers who would be curtailed, using the requirements of an average customer at each EDD level.

[16] Liberty used calendar years for this analysis, picking the coldest day for each calendar year.

- That equivalent number of customers was converted into numbers of residential and commercial and industrial (C&I) customers, using the Company's year-end 2000 ratio of C&I customers to total customers.
- The cost consequences of curtailment were estimated as a) the costs of remodeling (to repair damage due to freezing) for residential customers, and b) "the estimated cost of one day's service disruption" for C&I customers.
- Proportions of customers affected (25% and 75%) were used to develop a range of "probability-weighted damage costs" as a function of peak-day EDD.

The "cost" side of the cost/benefit calculation was also developed as a range, of costs that would be incurred to provide sufficient supply at each incremental EDD, again using 1,357 MMBtu/EDD to estimate how much additional supply would be required for each incremental EDD. The cost values selected were based on the following:

- Low side: Add propane vaporization capacity
- High side: Add 365-day pipeline capacity.

Select the Standard

The design-day standard was selected by super-imposing the cost curves on the benefit curves, and observing where the curves intersect; *i.e.*, where the incremental benefit of avoiding curtailment just equals the incremental cost of providing supply. In fact, since both costs and benefits were developed as ranges, the intersection of the curves is also a range: 77 to 84 EDD. The Company picked 79.6 EDD (rounded to 80), in order to use the same probability of occurrence as KEDNE uses in Massachusetts.

Liberty Concern

Liberty's concern with this analysis is the method, not the result. What is wrong with the method is that a Company would not curtail an average customer; rather, it would curtail lower-priority customers, pursuant to a Commission-approved curtailment plan. Thus, the "benefit" of avoiding curtailment that is utilized by ENGI in its model, expressed in terms of the value of gas service to marginal customers on the peak day, is likely to be considerably less than the $1.0 million to $5.8 million that is suggested by the Company's analysis.[18]

[17] The source of this number is not clear. Chart III-C-2 in the IRP provides regression coefficients for each calendar month. The highest of those is 1,306 EDD/MMBtu, for February.

[18] Liberty notes the low-upgrade-costs estimates, however. Chart III-E-6 indicates the Company's assumption for additional propane capacity as $48.84/MMBtu, which is described as the 'cost of adding propane vaporization capacity' on p. III-38. This cost looks more like a one-time capital cost of buying and installing additional vaporization, rather than an annual revenue requirement for additional capacity, which is the parameter that would be comparable with the Company's numbers for adding pipeline capacity (the high-upgrade-costs alternative). See **http://www.altenergy.com/Pricelists/GeneralPriceList2004Letter.pdf**. Thus, Liberty expects that both the benefit of avoiding curtailment and the marginal cost of providing additional supply are considerably lower than are suggested by Chart III-E-7, and proper application of this analysis might not result in a design-day standard that was less than 80 EDD.

In general, Liberty supports the idea of cost/benefit analysis in gas-supply planning. The proper application of such analysis here, in our view, would be in contingency planning for a peak period, such as the one experienced January 9-15, 2004. As noted above, our analysis suggests that, for ENGI's service territory, an 80 EDD day has a probability of occurrence of 4.25 percent, not 2.14 percent. The Company points out that the January, 2004 period is not the coldest seven-day period in its EDD data base for Manchester.[19] Liberty has not tried to estimate the probability of recurrence of such events, but two in the last six years seems sufficiently frequent to warrant detailed contingency planning. Thus, we recommend that the Staff and the Company discuss the development of a detailed contingency plan for a seven-day period with the weather characteristics of the mid-January, 2004 period. The contingency plan should be consistent with the Company's curtailment plan, and should be prepared on a coordinated basis.[20] (Additional details of this recommendation are presented in the Recommendations section of this chapter, below.)

In today's gas market, LDCs generally have supply alternatives short of curtailing firm customers, even under the most extreme weather conditions. An LDC can supplement the pipeline supply, storage, peaking plants, and interruptible contracts that are in its committed supply portfolio with spot gas or purchases of gas from marketers or customers if it is willing to pay enough. That availability would be a function of the number of pipelines serving the utility's territory, location on the pipelines, number and types of large customers, number of marketers serving in the region, and perhaps other parameters. An LDC operating in a market that has more of these options available to it may tend to limit assets acquired in advance to those sufficient to meet historical peaks. Conversely, an LDC like ENGI with only one principal pipeline connection, but access to a number of supplemental resources, must plan intensively in order to get the most value out of the resources that it has available.

The Company's IRP presents a "cold-snap" analysis, which is discussed below. The Company's analysis assumes normal weather to a point in early January, then a cold snap with the weather that the Company experienced in January, 2004. The Company's analysis concludes that, had the specified weather occurred in the first week of January, 2005, the Company's current portfolio would have handled it. Liberty's particular concerns with the Company's analysis are discussed below. Suffice it to say here, however, that this analysis is not the contingency planning that we have in mind.

The Design-Year Standard

The Company's process for selecting the design-year standard also uses a three-step process:

1. Statistical analysis of annual EDD data
2. A cost/benefit analysis to evaluate the cost of maintaining supply against the benefit of avoiding curtailment

[19] The Company notes that the coldest seven-day period in the data base was between January 16 and January 22, 2000. 2004 IRP, p. IV-21.

[20] In its response to our Data Request No. 1-48 (Docket No. DG 04-133/DG04-175), the Company reported that it is currently revising its curtailment plan.

3. Select a standard where costs and benefits match.

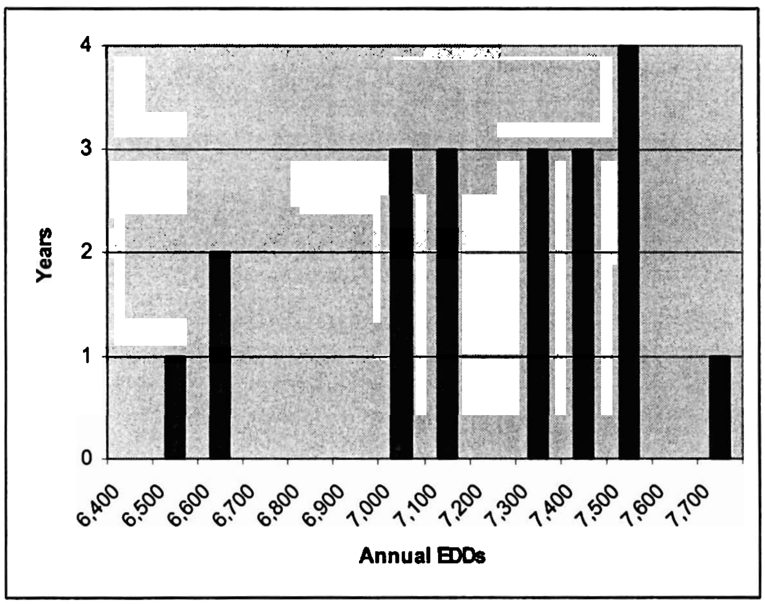
Again, each of the three steps is addressed in turn.

Statistical Analysis of the Coldest Years

The Company first computed calendar-year totals for EDD at the Manchester weather site for the years 1981 through 2000. These data are reported to be normally distributed, with a mean of 7,068 EDD, and standard deviation of 416.9. The Company then estimated annual sendout as the annual EDDs were increased from 7,068 to 8,300 in 100-EDD increments.

Liberty's analysis earlier in this chapter raised a question about whether the annual EDD data represent a normal distribution. The figure below (Figure II-2) presents a frequency distribution of annual EDD data. Again, this plot does not look like a normal distribution, and the high and low values are separated from the rest of the data. As with the daily data, however, we understand why the Company assumes a normal distribution.

Figure II-2
Frequency Distribution of Annual EDD Data
(1981-2000)



Cost/Benefit Analysis

The benefit, for the purpose of cost/benefit analysis, is estimated by the number of days of curtailment, times the economic penalty associated with the curtailment, expressed as cost per day, and developed from data on Gross State Product (GSP) for New Hampshire. The method assumes the current portfolio of pipeline, storage and peaking (supplemental) capacity, then observes the limits of the portfolio as the number of EDD is increased (in increments of 100).

To determine the number of days that a supply shortfall would represent, ENGI analyzed its requirements for supply at various EDD levels, assigned requirements to particular supply sources, and, using the average annual EDD as the baseline, estimated when supply sources would be in deficit, as well as the quantity and duration of such deficit. This approach found that the portfolio would be short pipeline capacity late in the non-heating season,[21] it would be short storage late in the heating season (March and April), and it would be short peaking capacity through the middle of the heating season (January, February, March).[22] The Company takes these estimates and turns them into a blend of pipeline, storage and peaking that is needed to maintain service at each increment of 100 in annual EDD.

Anticipating that the shortfall would be imposed on C&I customers, the Company comes up with a number of days of interruption for each increment of 100 in EDD. The method multiplies the number of days of interruption by the GSP per day to obtain an estimated benefit of avoiding interruption, again for each increment of 100 EDD. The method then assumes proportions of C&I customers actually affected at each increment of 100 EDD (25%, 50% and 75%) to develop a range of benefit.

On the cost side, the Company also uses a range of estimates:

- Low side: $3.50 per MMBtu for a winter-period supply contract (observed value for the winter of 2000/2001)
- High side: $6.50 per MMBtu for market-area spot purchases (observed value for the winter of 2000/2001).

Both sides of the range seem to assume that city-gate capacity is available. The range in estimated cost is for commodity, to put into capacity that is already under contract.

Select the Standard

As with the peak-day method, the two ranges are compared, and a value (7,870 EDD) is picked. Again, the probability of occurrence of the selected value is the same as the probability of the value that the Company uses for Massachusetts.

Liberty Concern

Liberty's concern, again, is with the method, not the result. As noted in Table II-2 (Distribution of Monthly EDD) above, Liberty estimates that the design year would have 7,821 to 7,898 EDD[23], using the criterion that there is a 95-percent probability that the level of EDD experienced in any year in the future would be less than or equal to that number. As discussed

[21] N.B.: there is a mistake in the text on this point: p. III-42.
[22] This result is presented in Chart III-E-9, on p. III-68.
[23] The reason for the range is that one value is for calendar years, and the other is for November-to-October years.

above, this criterion is in broad use among companies that are too small to justify more sophisticated weather analysis.

Liberty's concern with the method is that it seems to presume a static gas-supply portfolio. Given that the objective of gas-supply planning is to develop the portfolio of gas-supply resources that satisfies the load at least cost. In this instance, Liberty would start with the result of the Company's analysis – annual EDD of 7,870 – and work back to the proper portfolio. The Recommendations section of this chapter presents our recommended approach in more detail.

Step 5: Determine Customer Requirements Under Design Weather Conditions

The Company's method concludes with estimates of customer requirements under design-year weather conditions. "Springboard" year requirements are re-calculated for the different weather, and then the Company's estimates for annual incremental load growth are added, as is done for the normal-weather case.

Liberty also estimated customer requirements under design-year weather conditions, using the purely econometric methods described earlier in this chapter. The table below compares our results with the Company's. Again, Liberty's requirements estimates are close to the Company's, but ours are higher. Again, the difference increases over time.

Table II-6
Customer Requirements, Base Case Demand Scenario, Design-Year Weather
(MMBtu)

	2004-05	2005-06	2006-07	2007-08	2008-09
ENGI results	14,353,600	14,818,000	15,230,300	15,650,000	15,891,700
Liberty results	14,415,053	14,918,737	15,422,421	15,926,105	16,429,789
Difference, %	0.43%	0.68%	1.25%	1.73%	3.28%

Sources: ENGI results, Chart III-A-1; Liberty results computed as described.

2. Design of the Resource Portfolio

Basic Portfolio Analysis

In order to generate a long-term resource plan, the Company evaluated the current resource portfolio in relation to its requirements forecasts. To this end, the Company used the SENDOUT® model to determine whether the existing portfolio will meet forecasted demand.

The Company assumed that its current resource portfolio is representative of the portfolio that will be used for all of the years of the forecast. The Company analyzed three demand scenarios: base case, low-demand, and high-demand. In addition, the Company also analyzed a "cold-snap" scenario which, compared to the base case, assumes incremental load in January.

The Company's analysis found that the current portfolio will meet design-year requirements throughout the forecast period. Additional peak-day supply capacity is likely to be required as follows, however.

Table II-7
Additional Peak-Day Capacity Requirements
(MMBtu/day)

Winter	Low Demand	Base Case	High Demand
2004/05	0	0	0
2005/06	0	0	0
2006/07	0	2,000	4,000
2007/08	0	4,000	8,000
2008/09	2,000	6,000	10,000

Source: IRP, pp. IV-18, 19, 20

Because these requirements are small relative to the Company's current peak day (131,800 MMBtu/day in 2004/05), the Company concludes that the appropriate course is to monitor the factors that drive the need for incremental capacity to determine when the additional capacity will be needed. Those factors are listed as follows:

- Realization of forecasted load growth;
- Migration of new load directly to third-party suppliers;
- Customer participation in DSM programs; and
- Other factors that influence gas demand, such as energy legislation and environmental considerations.

The Company observes that a number of its supply-related contracts expire during the five-year period covered by this IRP. The table below, taken from the IRP filing, lists the contracts with their contract quantities and scheduled expiration dates. Thus, Liberty's sense is that the Company has considerable opportunity to try to improve the fit between its capacity portfolio and its load. Liberty would encourage the Company to conduct a thorough portfolio analysis to identify supply-resource options to pursue as these expirations present opportunities.

Table II-8
Expiring Gas Supply Resources

Contract	MDCQ	Annual Quantity	Date of Expiration
AES Londonderry, L.L.C.	15,000	450,000	9/30/07
Alberta Northeast Gas Limited	4,000	1,460,000	10/31/06
BP Canada Energy Company	1,599	583,635	3/31/07
CoEnergy Trading Company	20,000	2,000,000	3/31/04
Distrigas of Massachusetts Corporation FCS023	8,000	1,208,000	10/31/05
Distrigas of Massachusetts Corporation FLS142		100,000	3/31/04
Distrigas of Massachusetts Corporation FLS139		50,000	10/31/04
EKT Asset Management Agreement	Up to 77, 833		03/31/06
Honeoye Storage Corporation	1,957	245,280	04/01/05
National Fuel Company N02358	6,098	2,225,770	3/31/05
National Fuel Company O02357	6,098	670,800	3/31/05
NEXEN Marketing	1,600	584,000	3/31/07

Liberty observes that the Company's IRP focuses on the adequacy of the current resource portfolio to meet the forecasted design-day and design-year demands, but does not address whether the portfolio is optimal for current or anticipated loads. The Company explained to Liberty during a technical session[v] that it does perform such an analysis, but the IRP's text does not reflect this in any detail. Liberty regards this as a significant omission, which should be addressed, either in a revision to this IRP or in a subsequent filing.

In order to identify the optimal resource portfolio, a utility should first identify the available and potentially available capacity resources and their respective costs. Capacity includes pipeline transportation capacity; injection, storage and withdrawal capacities of underground storage facilities; and LNG and propane-air storage and vaporization capacities. Since the structure of ENGI's portfolio can change only when a capacity resource can be changed, the Company must also determine when each capacity contract expires and each existing resource can be expanded. With these data input to the Company's least-cost planning model, the net present value cost of selected resources to meet the forecasted demands can be determined. From this analysis, the

Company can identify the mix and timing of resource additions expected to minimize gas costs under a given set of price and demand forecasts, and capacity assumptions. The text of the Company's IRP should reflect this process to ensure that it is implemented by the Company.

Projected commodity costs can also be a factor, since the configuration of pipeline and storage facilities can be affected by commodity costs. Commodity costs may be more uncertain than capacity costs, but the effects of changing commodity costs can (and should) be evaluated with sensitivity analysis.

Cold Snap Analysis

In addition to the design-day, design-year and normal-year planning standards, the Company also evaluated a 'cold-snap' weather scenario. The purpose of this analysis was to assess the ability of the Company's supply portfolio to accommodate a protracted period of very cold weather. For this analysis, the Company used weather from the week of January 9 through January 15, 2004. This period produced 447 EDDs of space-heating requirements, and included a design-day occurrence of 80 EDD (January 15).[24] The Company analyzed the effectiveness of the portfolio against a normal-weather EDD pattern for most of the year, but with the 'cold-snap' week inserted for January 3 through January 9 (beginning on a Monday).[25] The IRP reports that the simulation results showed that the Company's portfolio was able to meet the cold-snap requirements adequately.

The Company's presentation of the results of its analysis (Chart IV-D-46) suggests that on-system facilities and contracted resources were able to handle the cold-snap scenario without having to resort to spot-market purchases during the peak period. Actual experience during the week of January 9-15, 2004, however, included some spot-market purchases of extremely expensive gas. Liberty believes that the Company's experience during that week provides an excellent basis for a further discussion with the Staff regarding contingency planning, as we have recommended elsewhere in this chapter.

The Seven-Day Rule

The Commission's "seven-day" rule (PUC Rule 506.03) requires jurisdictional companies to maintain on-site storage capability sufficient to provide peak-shaving supplies for a maximum-design cold period of seven days from December 1 through February 14 of each winter. The required storage level is reduced to 75 percent of that level from February 15 to February 28, then to 50 percent from March 1 to March 31. The text of the rule is reproduced as Appendix II to this chapter.

The Company conducted an analysis of the minimum supplemental inventories that it would require throughout the heating season in order to comply with this rule, assuming its current supply-resource portfolio, its Base Case requirements forecast, and observed weather over the

[24] For this evaluation, the 2004 week was favored over the week of January 16-22, 2000; the latter had 450 EDD but the peak day was only 74 EDD.
[25] The scenario used Base Case demand.

past 23 years. The Company reported that the analysis showed that it had to maintain minimum inventory levels somewhat higher, and for longer time periods, than would be indicated by its experience. The Company has apparently also expressed concern about the restrictive nature of the seven-day rule in the past.

Liberty believes that, while the analysis provided in the IRP is useful in determining adequate capacity, it does not bear upon the operational availability of storage inventories. As a part of a settlement in Docket No. DG 04-152 (the Winter 2004/05 Cost of Gas proceeding), the Company implemented "rule curves" dictating minimum pipeline (natural gas) storage inventory requirements. These rule curves were not mandated at the time that the Company prepared its IRP. We agree with the Company that the seven-day rule should be re-evaluated, particularly in light of the storage-inventory rule curves, but the analysis should be conducted in light of the constraints observed during the extreme weather events of mid-January, 2000, and mid-January, 2004. This will enable the Company to assess the ability of the Company's dedicated resources – not only storage and peaking facilities, but also LNG and propane trucking resources – to meet system requirements. Circumstances under which supplies might be displaced from the Massachusetts affiliates would also be relevant considerations. As discussed below, the Company should work out with the Staff the details of an appropriate analysis on this point after the Company's renegotiation of its LNG contracts and necessary propane capacity re-evaluation in 2005.

D. Conclusions

1. ENGI's load forecasts should reflect current data and as much New Hampshire-specific data as is reasonably available.

Our Tables II-1 and II-6 suggest that the Company may be under-forecasting customer requirements in its service territory over the next few years. As discussed in the narrative around those tables, a reason for this discrepancy could be that the Company's IRP used use-per-customer data in its forecasting that is out-dated, or not specific to New Hampshire, or both. Because of the relatively isolated nature of ENGI's service territory, and the relatively long lead times associated with most supply projects, under-forecasting is more of a problem than over-forecasting. Having to find more supply capacity than you thought is likely to lead to forced choices from among expensive alternatives.

2. The Company's design-day and design-year evaluations reach acceptable results, but its methods are suspect.

Liberty finds the Company's design-day and design-year results to be acceptable at this time, as both seem to be in the 95-to-97-percent confidence level (three- to five-percent probability of occurrence) range that is common in our experience. We are hopeful that the Company will update its methods and its analysis soon, however, and will be able to provide weather analysis that will incorporate Liberty's suggested improvements.

Cost/benefit analysis has a place in supply planning, but that place is not in the selection of design criteria. Design criteria, in our view, should be developed from weather analysis.

3. The Company's IRP does not include an analysis to identify the combination of resources that minimizes gas costs to firm customers over the long term.

The text of the Company's IRP does not discuss the issue of whether the existing resource portfolio is optimal. The IRP should expressly identify the combination of resources that minimizes gas costs to firm customers over the long term by discussing a four-step analysis as follows: (i) Identification of all available and potentially available capacity resources, along with their respective costs; (ii) Identification of each existing resource that can be varied within the planning horizon and when; (iii) Running the planning model to evaluate various resource configurations, under different gas demand and gas price scenarios; and (iv) Evaluating the model results. If the Company already performs such an analysis, it should be reflected in the IRP.

4. Access to additional peaking resources allows a fresh look at the 'On-site Storage' rule.

As noted earlier, NH PUC Rule 506.03 regarding on-site storage requires each New Hampshire utility to "maintain an on-site storage capability in connection with the operation of its gas distribution system between December 1 and February 14 of each year which will provide peak-shaving supplies for an estimated maximum-design cold period of 7 consecutive days." Under the rule, between February 15 and February 28, the above minimum on-site storage capacity may be reduced to 75 percent of the total requirement, and between March 1 and March 31 the minimum on-site storage capacity may be reduced to 50 percent of the original total requirement. Furthermore, the utility is required to report this information each Monday from December 1 through April 1.

Our understanding is that the rule is intended to assure adequate on-site liquid gas inventories to cover all anticipated LNG and propane peak-shaving demand during the coldest consecutive seven-day period. Liberty understands that the requirement assumes all contracted firm pipeline deliveries to the ENGI city gates during this period can be deducted from total demand requirements, and all remaining demand requirements for the seven-day period must be made up by on-site liquids without refills from third-party sources.

The Company's peaking-resource options now include additional propane storage in Haverhill, MA. That additional storage is not considered by the rule as 'On-site Storage'. That additional storage can be used in meeting peak-shaving needs, however. With firm trucking arrangements in place, Liberty expects that the Haverhill storage capacity would fall under the Rule 506.03 Section (c), which allows consideration of 70 percent of the capacity as on-site storage.

A concern regarding the seven-day requirement is that it may prevent the Company from using its available peaking capacity, encouraging it instead to make expensive spot gas purchases on peak-demand days. We concur with the Company that "the seven-day rule" bears re-examination. The Company should discuss its options for peak-shaving as part of its 'cold snap' analysis, and include this information in a seven-day storage requirement waiver request if appropriate.

E. Recommendations

1. The Company should update its load forecasts, and make them more New Hampshire-specific.

While the results from the Company's end-use model forecasts and Liberty's econometric forecasts are pretty close, if the Company plans to stick with end-use models, it should update the energy-related input factors and re-calibrate the model. If the Company decides to change to an econometric approach, it needs to develop customer and use-per-customer forecast equations for each customer class, which would involve a comprehensive study.

Regarding the Company's long-term demand forecasting methodology, Liberty cannot insist that the Company use the econometric methods that we favor, rather than the springboard and end-use modeling approach that it has been using. We note, however, that the end-use modeling approach requires a large amount of input data that is relatively costly to collect and maintain up-to-date[26], and some of which is not available for New Hampshire. Econometric methods, on the other hand, are primarily driven by intensive analysis of ENGI's own most-recent sendout and customer-use records. In response to data requests, the Company provided Liberty with approximately 15 years of monthly billing data and four years of daily sendout data. Perhaps additional data is available from Company records. That data is adequate to estimate demand for most customer classes, especially all heat-sensitive customer classes.

2. The Company should prepare a peak-period contingency plan, and file it with the Company's revised curtailment plan.

As noted in our discussion of selecting the peak-day standard, LDCs generally have supply alternatives short of curtailing firm customers, even under the most extreme weather conditions. The issue is cost: what resources does the Company maintain in its committed or contracted portfolio, and what resources does it "go out and get" when conditions warrant?

In our experience, this question is answered by LDCs through careful analysis. The analytical question is, given the actual costs of committed and potentially committed resources, and a range of possible costs for uncommitted but potentially available resources, what level of committed resources represents the least-cost mix for the Company's customers?

The metric for this analysis is usually some form of expected value for the total cost of serving the Company's customers over some time period. Our experience is that LDCs find that the break-point occurs in the three-to-five-percent probability range. In other words, for load

[26] See, *e.g.*, Sections 4 and 5 (pp. 31-44) of Appendix A to the 2004 IRP.

conditions[27] with a probability greater than three to five percent, companies would have on-system supply resources sufficient to supply all firm customers. For load conditions with a probability lower than that, they would expect to go to the markets and find additional supply resources in the event those load conditions occur.

As suggested by our (and ENGI's) weather analyses, load conditions with a three-to-five-percent probability should be expected to occur, just not very often: once in 20 years for five-percent probability, to once in 33 1/3 years for three percent, to once in 46.69 years for the Company's 2.14 percent. Even if analysis shows that it is not cost-effective to maintain on-system or committed supply resources at this level, LDCs must be prepared to meet their firm customers' requirements under these low-probability conditions.

The answer, in our experience, is careful planning. When these rare, but expected, load conditions occur, companies must have plans for what customers will be served, and where the supplies to serve them will come from. ENGI should have such plans.

The Company needs to look carefully at who would face curtailment in the event of a weather event with a three- to five-percent probability of occurrence. This analysis should not be generalized, but should take into account the specifics of providing supply to customers at different locations across ENGI's distribution system.

This analysis should identify customers or areas within the distribution system for whom curtailment is acceptable, and those for whom it is not. The Company should then present to the Commission a plan for providing supply to the at-risk customers for whom curtailment is not an option, and a curtailment plan tailored to the specifics of this analysis for those customers who would be curtailed.

The Company included a section on Contingency Planning in its IRP.[28] Company representatives confirmed,[vi] however, that the kind of contingency planning recommended here was not what they had in mind.

With two low-probability weather events in the last six years, Liberty considers this analysis to be a matter of some urgency, that should be presented to and considered by the Commission as soon as possible. The Company should consult with the Commission's Staff regarding when to file these plans.

3. The Company's IRP should expressly reflect that it performs a portfolio analysis that varies all contract levels.

Liberty acknowledges that the Company's ability to change its portfolio is limited by in-place contracts, in-place facilities, etc. However, it is still important to ensure that the Company is taking appropriate steps to optimize its portfolio as opportunities present themselves.

[27] Our use of the term *load conditions*, rather than *weather conditions*, is intended to be more precise. For a load like ENGI's that is so heavily weather-driven, the two are practically the same thing.
[28] Section IV.G., pp. IV-24 to IV-27.

Liberty encourages the Company to take a broad look at the supply resources in its capacity portfolio. Using an optimization model such as SENDOUT (currently being used by the Company), the Company can seek adjustments to its contract levels, if appropriate, as they expire. Certain features of the Company's supply-capacity portfolio, such as taking virtually all city-gate deliveries from Tennessee Gas Pipeline (TGP), are fixed. It is possible, however, that use of that TGP capacity to deliver pipeline, storage and/or peaking supplies might be varied in response to changes in the prices of those resources, and/or in response to changes in the Company's load. The IRP does not address the Company's efforts to perform such an analysis.

The IRP identifies benefits for ENGI from sharing propane (Haverhill, MA), LNG (trucking capabilities) and the shared Operational Balancing Agreement (OBA) on TGP, with the KEDNE companies in Massachusetts. The ability to deliver on-system resources from Massachusetts to New Hampshire by way of displacement on TGP is also mentioned. None of these possibilities are reflected in the analysis in the 2004 IRP or the 2004/05 Winter COG filing. To the extent that the Company cannot rely on these resources during peak periods, that can be reflected in the filing.

Further, the Company has presented no analyses involving gas supply optimization scenarios with variable demand costs. Such scenarios can be used to identify how to resize existing contracts to better match the load duration curve. None of the SENDOUT runs presented by the Company reflect any assessment of variable demand costs to evaluate the adequate level of each resource in the portfolio, or the potential value of additional resources. If such an evaluation has not been performed, it should be. To the extent that the evaluation is simply not reflected in the text of the IRP, the next IRP filing should provide a discussion of the evaluation that was done.

4. The seven-day storage rule requirements and storage rule curves should be re-evaluated once the Company renegotiates its LNG contracts.

Upon renegotiating its expiring LNG contracts, the Company should evaluate the extent to which the design of its portfolio may be constrained by the seven-day storage rule requirement, and whether the recently-adopted rule curve now provides adequate protection against potential premature storage depletions. The Company should work with the Commission's Staff to configure the appropriate analysis in this area.

Appendix I

Regression Analysis, Use per Customer

In order to illustrate trends in use per customer over time, Liberty developed a monthly regression for the use per customer (UPC) of ENGI's R3 residential customer class. This class represented 44 percent of ENGI's load in February, 2004[vii]. The same regression was run on monthly billing data (numbers of customers and volume) for that rate class, and EDD data, from 1990 to 2000, and from 1995 to 2004.

Table IIA-1
Regression Analysis, Use per Customer, 1990-2000

Dependent Variable: UPC_RES_R3
Method: Least Squares
Sample: 1990:01 2000:12
Included observations: 132
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
ACTEDDS	0.005100	0.001409	3.619318	0.0004
_DUM01	10.46270	1.975053	5.297426	0.0000
_DUM02	10.97561	1.662693	6.601106	0.0000
_DUM03	9.150712	1.373862	6.660578	0.0000
_DUM04	7.918348	0.898582	8.812050	0.0000
_DUM05	4.956845	0.469242	10.56353	0.0000
_DUM06	3.390305	0.227154	14.92515	0.0000
_DUM07	2.552001	0.162655	15.68961	0.0000
_DUM08	2.131474	0.171778	12.40829	0.0000
_DUM09	1.708693	0.322761	5.293991	0.0000
_DUM10	1.909708	0.731286	2.611439	0.0102
_DUM11	4.229283	1.153961	3.665012	0.0004
_DUM12	6.497750	1.674683	3.879987	0.0002
TREND	-0.005721	0.002055	-2.784277	0.0063

R-squared	0.976622	Mean dependent var	8.109024
Adjusted R-squared	0.974047	S.D. dependent var	5.431221
S.E. of regression	0.874972	Akaike info criterion	2.670754
Sum squared resid	90.33798	Schwarz criterion	2.976506
Log likelihood	-162.2698	Durbin-Watson stat	1.870639

Table IIA-2
Regression analysis, Use per Customer, 1995-2004

Dependent Variable: UPC_RES_R3
Method: Least Squares
Sample(adjusted): 1995:01 2004:06
Included observations: 114 after adjusting endpoints
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
ACTEDDS	0.005994	0.001482	4.043556	0.0001
_DUM01	8.228054	2.001217	4.111526	0.0001
_DUM02	9.994218	1.803225	5.542413	0.0000
_DUM03	8.033646	1.574252	5.103153	0.0000
_DUM04	6.634446	1.069043	6.205967	0.0000
_DUM05	4.237759	0.648204	6.537689	0.0000
_DUM06	3.087361	0.426704	7.235374	0.0000
_DUM07	2.346695	0.364588	6.436560	0.0000
_DUM08	1.833464	0.373116	4.913930	0.0000
_DUM09	1.332234	0.469626	2.836795	0.0055
_DUM10	0.706073	0.900913	0.783731	0.4351
_DUM11	2.881532	1.320208	2.182635	0.0314
_DUM12	5.215609	1.934668	2.695868	0.0082
TREND	-0.001017	0.003018	-0.336961	0.7369

R-squared	0.971397	Mean dependent var	8.091907
Adjusted R-squared	0.967679	S.D. dependent var	5.457872
S.E. of regression	0.981218	Akaike info criterion	2.914542
Sum squared resid	96.27889	Schwarz criterion	3.250566
Log likelihood	-152.1289	Durbin-Watson stat	2.154777

These regressions make use of monthly dummy variables (_DUM01 to _DUM12) to calculate different base use levels for each month, actual EDD (ACTEDDS) to calculate heat-sensitive use, and a TREND variable, which is 1 for January 1990, and increases by 1 each month.

The important result is that the statistically-significant negative trend in ENGI's residential use per customer in the 1990-to-2000 regression gives way to a lower and statistically-insignificant trend in the 1995-to-2004 regression. This result shows that a negative trend in weather-normalized use per customer in this rate class subsides in the more-recent period.

Appendix II

7-Day On-Site Storage Rule

NEW HAMPSHIRE CODE OF ADMINISTRATIVE RULES
Chapter: 500 RULES FOR GAS SERVICE

Puc 506.03 On-site Storage.
(a) Each utility shall maintain an on-site storage capability in connection with the operation of its gas distribution system between December 1 and February 14 of each year which will provide peak-shaving supplies for an estimated maximum-design cold period of 7 consecutive days.

(b) Railway tank cars on gas company rail sites and guaranteed pipeline transmission capacity for firm gas supply shall be considered as on-site storage.

(c) A utility may count as on-site storage 70% of the guaranteed daily delivery capability over a 5 day period from a dependable bulk fuel supply point any situation in which the utility:

(1) Owns or leases tank trucks;
(2) Has a fuel supply purchase contract; or
(3) Has a dedicated service contract;

(d) Between February 15 and February 28, the above minimum on-site storage capacity may be reduced to 75% of the total requirement of each utility.

(e) Between March 1 and March 31, the minimum on-site storage capacity may be reduced to 50% of the original total requirement.

(f) Each utility shall notify the commission's gas safety engineer each week during the period from December 1 through April 1 of its on-site supply of supplemental fuel.

(g) The information required by (e) above shall be reported on each Monday, or the next day following a state holiday, no later than 4 p.m. and may be made by telephone.

Source. (See Revision Note at Chapter heading for Puc 500) #6445, eff 1-28-97

III. Short-Term Planning (Dispatch and Balancing)

A. Background

1. Gas Dispatch

Short-term gas-supply planning for an LDC involves deciding on a day-to-day basis which of the available supply resources to use to supply the anticipated load. The process involves obtaining a weather forecast, estimating system requirements on the basis of that forecast, and then nominating amounts of supply to be delivered to serve the load. System requirements must be adjusted for amounts to be supplied by third-party suppliers (gas marketers serving customers behind the Company's city gates), and for prior-period imbalances; *i.e.*, deliveries to the city gate that did not exactly match customer usage.

The Company estimates system requirements from the forecast using a simple base-load-plus-heating-increment calculation. Sendout and EDD data from a like month are regressed against each other to yield a heating increment, then that increment is multiplied by the expected EDD value for the current gas day, plus the succeeding three days.[viii]

The Company reports[ix] that it accomplishes the dispatch function using a spreadsheet tool, referred to as the Daily Game Plan, that is shared by Gas Supply and Gas Control. This spreadsheet balances the anticipated sendout requirements with the supply resources available to the Company based on existing contractual entitlements, including the resources available at the city gates as well as on-system supplemental supplies. The spreadsheet balances demand and supply at the system level as well as the area-specific level. Three areas are forecast for Boston Gas, plus one each for Cape Cod, Lowell and Essex in Massachusetts, and for ENGI in New Hampshire.

Each morning, Gas Supply and Gas Control review the Daily Game Plan. Gas Supply schedules any needed volumes to the city gate; if on-system production is necessary, Gas Control makes the necessary arrangements with Gas Production. After this conference, Gas Supply notifies its suppliers – primarily Merrill Lynch Commodities, Inc. (*ML Commodities*),[29] its asset manager and principal supplier – of the Company's requirements at its city gates. This process is then repeated and updated during the day as required based on changes in the weather and other conditions.

As noted earlier, and discussed in more detail in the next chapter of this report, the Company has an agreement with ML Commodities to manage and dispatch its long-line transportation and storage capacity. The capacity managed by ML Commodities can be summarized as follows:

[29] In late 2004, ML Commodities acquired the trading assets of EKT, and succeeded it under the terms of the AMA.

Table III-1
Summary of ENGI's Capacity under Management

Source	Capacity (MMBtu/day)
TGP Z0-Z1 -> Z6 capacity	21,596
TGP Z4-Z5 -> Z6 capacity (storage)	28,115
TGP Z5 -> Z6 Niagara, NY	3,122
TGP Z5 -> Z6 Iroquois, NY	4,000
TGP Z6 -> Z6 Dracut, MA	20,000
PNGTS Pittsburg, NH to Dracut, MA	1,000
Total Capacity Managed by ML Commodities	77,833

All firm transportation capacities under the Company's asset-management agreement (AMA) with ML Commodities are available for 365 days. The TGP capacity of 20,000 MMBtu/day at Dracut, MA is supplied by CoEnergy during December, January and February. Deliveries under that contract were initially for a maximum of 110 days (91 of which were from December 1 through February 29, 2004) between November 1, 2003 and March 31, 2004.[30] The contract provided for the potential to be curtailed for ten days, not to exceed three days in any one month. The curtailment provision was in effect during the Winter 2003/04 season; it was eliminated when the contract was renewed for the 2004/05 and 2005/06 winters.[x]

The Z0/Z1-to-Z6 capacity is supplied by U. S. Gulf Coast production-area purchases, which are priced pursuant to the AMA. The Z5-to-Z6 capacities are supplied through year-round Canadian supply contracts received at Niagara and Waddington, NY; those supplies are priced pursuant to the provisions of those contracts. Quantities supplied by CoEnergy are priced with reference to a market-area index. Base-load quantities delivered by ML Commodities using the Dracut capacity are priced with reference to a different market-area index.

The storage capacity provides access to a maximum daily withdrawal quantity of 28,115 MMBtu/day from annually-cycled storage inventory volumes of 2,580,131 MMBtu, under four storage contracts. Gas provided to storage by ML Commodities is billed to ENGI as though it was injected in equal amounts over the seven months of the storage-injection season. It is priced at the applicable base-load indices for the respective injection months.

[30] The Dracut capacity of 20,000 MMBtu per day became available in January 2003, while the related firm CoEnergy supply for that capacity became available on November 1, 2003.

Table III-2
ENGI Contracts Managed under the AMA

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS	DAYS
Tennessee Gas Pipeline Company	FTA	8587	FT	25,407	9,273,555	10/31/2010	10/31/2009	Evergreen Provision	365
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2010	10/31/2009	Evergreen Provision	71.43
Tennessee Gas Pipeline Company	FTA	632	FT	15,265	5,571,725	10/31/2010	10/31/2009	Evergreen Provision	365
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2006	3/31/2005	Evergreen Provision	110.00
National Fuel Gas Supply Corporation	FSST	N02358	FT	6,098	670,800	3/31/2006	3/31/2005	Evergreen Provision	110.00
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	4/1/1995	12 months notice	Evergreen Provision	125.83
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2011	3/31/2009	Mutually agreed upon.	109.96
Tennessee Gas Pipeline Company	FTA	11234	FT	9,039	3,299,235	10/31/2010	10/31/2009	Evergreen Provision	365
BP Canada Energy Company	-	-	Supply	1,599	583,635	4/1/2007	N/a	Terminates	365
Nexen Marketing	-	-	Supply	1,600	584,000	4/1/2007	N/a	Terminates	365
Tennessee Gas Pipeline Company	FTA	2302	FT	3,122	1,139,530	10/31/2010	10/31/2009	Evergreen Provision	365
Alberta Northeast Gas Limited	-	-	Supply	4,047	1,477,155	10/31/2006	N/a	Terminates	365
Iroquois Gas Transmission System	RTS-1	47001	FT	4,047	1,477,155	10/31/2011	10/31/2010	Evergreen Provision	365
Tennessee Gas Pipeline Company	NET-NE	33371	FT	4,000	1,460,000	10/31/2011	10/31/2010	Evergreen Provision	365
CoEnergy Trading Company Trading Company			Supply	20,000	1,800,000	2/28/2006	N/a	Terminates	90
Tennessee Gas Pipeline Company	FTA	42076	FT	20,000	7,300,000	10/31/2010	10/31/2009	Evergreen Provision	365
Portland Natural Gas Transmission System	FT 1999-01	1999-001	FT	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision	365
Entergy-Koch Trading, L.P.	-	-	Supply	77,783	Seasonal	3/31/2006	1/1/2005	Mutually agreed upon.	
			Total MDQ/MAQ:	77.833	22.118.216				

The cells highlighted in yellow in the table above indicate the city-gate deliverable capacities, corresponding to the total volumes managed by ML Commodities. The AMA specifies a tiered dispatch order, which in effect dictates the order in which resources will be used to meet daily sendout of up to 77,833 MMBtu.[31] During the first winter season (2002/03) that the AMA was in effect, the tiered dispatch order also prevented the use of resources beyond those managed within the AMA for days where the load did not exceed 77,833 MMBtu. This constraint was relaxed somewhat for the second and third years of the AMA.

Beyond these resources, ENGI has several other contracted resources available to meet peak demand requirements, listed in the following table:

[31] A detailed discussion of the Company's AMA is presented in the next chapter of this report.

Table III-3
ENGI's Company-Managed Supply Contracts

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
AES Londonderry, L.L.C.	-	-	Supply	15,000	450,000	09/30/06	3/31/2006	Mutually agreed upon.
Distrigas of Massachusetts Corp. *	FLS	FLS139	Liquid Refill	7 Trucks	50,000	-	-	-
Distrigas of Massachusetts Corp. *	FLS	FLS142	Liquid Refill	Up to 15 trucks	1,000,000	-	-	-
Distrigas of Massachusetts Corp.	FCS	FCS023	Supply	8,000	1,208,000	10/31/2005	4/30/2005	Mutually agreed upon.

* Contract currently being negotiated for an effective date of November 1, 2004.
Terms and Conditions expected to be similar to previous FLS139 and FLS142 contracts.
Distrigas FLS 139 is a dedicated 12 month liquid LNG refill contract to ENGI while the FLS 142 contract is a December-February 3 month liquids service refill contract shared among the KeySpan New England companies, with ENGI being allocated approximately 100,000 MMBtu for the 3 month period

Additionally, ENGI has:

- 34,600[xi] to 50,400[xii] MMBtu/day of propane vaporization capacity, with on-site storage capacity of 104,169[xiii][xiv] to 114,252[xv] MMBtu owned by ENGI, and off-site storage capacity of 42,216 MMBtu in Haverhill, MA that is owned by KEDNE but can be used by ENGI.
- 22,800[xvi] to 24,000[xvii] MMBtu/day of LNG vaporization capacity, with on-site storage capacity of 12,600[xviii] to 13,531[xix] MMBtu owned by ENGI. (Significant trucking capacity is required to provide service up to the maximum daily vaporization quantity.)

Dispatch is conducted for all of the KEDNE companies from the Company's offices in Waltham, MA. The sendout measurements of the peaking (propane and LNG) plants are tied in to Gas Control by the SCADA system. Dispatch in Waltham calls the plant operators each day, as necessary, and tells them when to turn on the peaking plants, and how much gas to vaporize into the system.

2. Gas Balancing

Balancing is the process of getting gas deliveries to an LDC's system to match usage by the LDC's customers. Balancing must be done separately for different customers, such as large-volume ones, and groups of customers, such as those served by a particular marketer. For an LDC, one of the groups that must be balanced is its system-supply customers.

The bulk of ENGI's gas is delivered via the TGP system. KEDNE's Massachusetts LDCs are also served by TGP, although Boston Gas, in particular, is also served by Algonquin Gas Transmission Company (AGT) and Distrigas of Massachusetts (DOMAC). KEDNE has a joint operational balancing agreement (OBA) for all of its TGP gate stations, so that all of the KEDNE companies can be in balance as a group, even as there may be some temporary imbalances among them. KEDNE might want to shift TGP supply from Massachusetts to New Hampshire, for example (or vice versa), for operational reasons. Under its joint OBA with TGP, the Company can do that, letting the "borrower" pay back the "lender" either in kind or in money. As long as the quantities taken into the KEDNE companies' systems as a group match the quantities delivered to those city gates as a group, TGP considers the KEDNE companies to be in balance. The Company argues that this arrangement provides significant value to the Company and its customers; it cannot be relied on for supply-planning purposes, however, because the joint OBA can be revoked at anytime by TGP.[xx]

Gas accounting within the KEDNE group of companies must be done for each of the four individually. Each has its own set of gas costs, and each has a cost-recovery mechanism that operates off of its costs. ENGI is served by TGP (only), and has a set of gas-supply contracts, including its own AMA, that flows through into its gas-cost rate. Each of the Massachusetts companies similarly has a unique set of supply assets. Thus, KEDNE must get the correct costs to each affiliate, in order to get each one's rates figured correctly.

B. Summary of Liberty Activities

The Commission's RFP requested that the consultant review the Company's supply planning models used in preparing its COG filings, and assess whether they are consistent with least-cost supply planning. The consultant was also to review the Company's gas-supply portfolio, and consider whether dispatch was being done on an economic basis.

As noted earlier, Liberty worked with the Staff to review the Company's Winter 2004/05 COG filing. Our testimony in that proceeding noted that reasonable dispatch decisions are important components of prudently-incurred gas costs. We also analyzed responses to data requests, and asked questions to ENGI staff during technical sessions held at the Commission's offices, and at the Company's offices in Waltham, MA. During the visit to the Company, Liberty and Commission Staff attended a morning meeting where the Daily Game Plan was discussed, and reviewed how the Company performed dispatch and balancing in general.

While at the Company's offices, Liberty and Staff went carefully through weather records, and dispatch and balancing records, for January 2004 to observe how dispatch and balancing were accomplished, and the reasons behind the Company's decisions during that month, in an effort to understand the decision processes in detail. The Liberty team prepared notes of our sessions with the Company, and a list of questions regarding items that we had not completely understood. Liberty left the notes and questions with the Company at the conclusion of the visit to allow the Company to correct any mis-impressions that the Company saw in our notes. The Company responded to our questions in writing, as was the Company's request. After the Company visit, Liberty also participated in another technical session where the Company's responses to Liberty's questions were discussed.

C. Analysis/Findings

1. Supply Models Used in COG Filings

In examining the Winter 2004/05 COG filing, Liberty found that the gas costs in that filing reflected runs of the optimization model[32] that the Company uses for all of its supply planning.

[32] The model that the Company uses is SENDOUT, by New Energy Associates.

The gas costs in the filing reflected normal weather and current load; hence, the dispatch constraints that are part of the Company's AMA with ML Commodities did not affect the dispatch assumed for the purpose of preparing the COG filing. In that case, the model runs used to prepare the COG filing did indeed reflect least-cost supply planning, and provided a reasonable basis for determining COG rates. The constraints affect dispatch under other weather conditions, however, and those conditions and the effect of the constraints are discussed in some detail in the next chapter of this report.

As noted above, the Company uses a simple spreadsheet model to prepare its Daily Game Plan. That model assists daily dispatch by indicating which resources will be required to meet the load for each day. That model is not utilized in the calculations that go into the COG filing; rather, it is for daily dispatch decision-making only.

Liberty did not find any model in use by the Company to test the effects of the AMA's dispatch constraints on dispatch or gas costs. This finding is discussed in some detail in the next chapter of this report.

2. Daily Dispatch

The pricing of the supply resources covered by the AMA is conducted pursuant to 'tiers', which are defined in the AMA. The pricing structure under the AMA assumes that all resources in each tier are dispatched before any resources in a succeeding tier can be used. The Company indicated on several occasions that this pricing structure was established in order to mimic the pricing that would be experienced if the Company were managing its own resources.[xxi]

Upon calculating its system requirements for the day (based on the weather forecast), the Company notifies the asset manager how much supply it needs that day. If the amount for ENGI is 77,833 MMBtu or less, then all of the supply comes from the asset manager, in the following order:

1. Canadian supply: Boundary, Alberta Northeast, PNGTS
2. Base-load: TGP capacity
3. Dracut supply: CoEnergy (April – October, December – February)[33]
4. Swing supply: TGP capacity
5. Gas from storage.

KEDNE's Daily Game Plan lists each of those sources, but contains no price or cost information, since the dispatch of those sources is established by the AMA.

As the load increases beyond the 77,833 MMBtu/day level, the Company has to make decisions. The first option is to dispatch the 8,000 MMBtu/day DOMAC contract. Beyond the 85,833 MMBtu/day level (77,833 plus 8,000), the Company must decide whether to turn on its LNG

[33] The Dracut supply comes after storage in November and March. The delivery capacity is available year-round at Dracut, but commodity is not contracted for April through October.

and/or propane/air peaking plants, and whether to buy supplemental supply. These decisions are made separately for the New Hampshire and Massachusetts LDCs.

If the Company buys supplemental (spot-market) supplies, a distinct amount is bought for each LDC. While an amount of supplemental supply delivered to ENGI (for example) could be an allocation via the shared operational balancing agreement on TGP, the Company prefers to order discrete amounts for each LDC, to facilitate documentation for cost-recovery purposes.

The amount of LNG or propane vaporized from the ENGI plants is a function of the inventory on hand and the refill capabilities. Storage at the New Hampshire peaking plants, particularly the LNG plants, is extremely limited: only one-half day at two of the three plants, and just over one day at the smallest of the three plants.

In view of the Commission's question regarding economic dispatch, we must reiterate that, for the first 77,833 MMBtu, at least, dispatch is conducted on the basis of the Company's agreement with its asset manager, not on the basis of economics. As noted above, however, the Company argues that the dispatch order in its AMA "mimics" economic dispatch.

Whatever supply-cost minimization is done on a day-to-day basis, for the first 77,833 MMBtu of supply, is done by the Company's asset manager, pursuant to the terms of the AMA. This activity is supposed to produce profits, which are shared by the Company's customers when flowed back to them through the Company's Gas Cost Rate. The asset manager charges ENGI the prices specified in the AMA for the supplies that it provides, not the costs that the asset manager incurs. We presume that the asset manager also uses gas-supply resources under contract to the Company, but not required for supplying the Company's customers, to conduct secondary-market activities. Those activities hopefully produce positive margins, which are then shared with the Company's customers as an offset to gas-supply costs.

3. Balancing

The Company reports that actual flows at ENGI's city gates are tracked by the Company's SCADA (Supervisory Control and Data Acquisition) system. SCADA is connected to each gate station with RTUs (Remote Telemetry Units); the RTUs provide flows through the meters at each gate station. At the end of each gas day, actual flows are compared to scheduled volumes, with the difference reported as an imbalance.[xxii]

As noted earlier, all of the KEDNE companies are consolidated under one OBA for their TGP volumes. The Company can access flow information for each gate station on TGP's reporting system, however, so it can monitor ENGI's imbalances separately on a day-to-day basis.

In response to a data request, the Company provided a group of monthly balancing statements from TGP.[xxiii] Those statements showed deliveries to individual ENGI gate stations varying widely from nominations to those stations, but showed them to be balanced (within TGP's tolerances) as a group.

The Company also provided its own measurements of flows through ENGI's city gates (as a group), and through the city gates of each of its Massachusetts LDCs. Those deliveries could be matched against nominations to assess imbalances. The information that we received for the Massachusetts affiliates was only for TGP; as noted above, those companies also receive gas from AGT and DOMAC.[34]

In an effort to understand the Company's processes for nominations and balancing, Liberty reviewed the nomination and flow information for January, 2004 in considerable detail. (Recall that this month included some of the coldest weather on record.) The table below shows TGP imbalance information for ENGI and for the KEDNE companies as a group (including ENGI) during the extremely cold period that occurred in the middle of that month. The table also shows the timing and price of purchases of spot-market gas for ENGI's account during that period.

Table III-4
January, 2004 TGP Imbalances and ENGI Spot-Market Purchases

Date	ENGI Imbalance (MMBtu)	ENGI Imbalance (% of nom.)	KEDNE Imbalance (MMBtu)	KEDNE Imbalance (% of nom.)	ENGI Spot Purchases (MMBtu)	ENGI Spot Price ($/MMBtu)
10	-6,382	-5.43	-1,616	-0.35	20,000(a)	$12.70
11	-2,071	-2.12	-19,158	-4.20	20,000(a)	$12.70
12	-4,982	-6.70	-6,748	-1.60	0	
13	388	0.37	3,916	0.79	15,000(a)	$7.70
14	-1,049	-0.82	4,694	0.95	20,000(a) +3,000(b)	$20.87(a), $17.50(b)
15	4,386	3.09	-969	-0.19	15,000(c)	$28.90
16	4,765	3.78	2,064	0.42	15,000(a)	$54.75
17	14,350	14.77	-5,990	-1.33	0	
18	6,849	7.69	15,191	3.51	0	

Sources: Company responses to DR Nos. 1-53, 1-54 under Docket No. DG 04-133/DG 04-175, and DR Nos. 5-6, 5-7 under Docket No. DG04-040.
Sources of spot purchases: (a) Emera Spot, (b) Third Party via EKT, (c) AES

A source of some concern is the apparent over-deliveries to ENGI on January 15 and 16, using extremely expensive gas, at a time when the Massachusetts companies were under-delivering. In response to our question, the Company provided the following answers:

- ENGI's CoEnergy contract volumes (20,000 MMBtu/day) were recalled on January 9, for flow dates January 10, 11, 12.[xxiv]
- On January 11, DOMAC liquid deliveries became restricted to half of the normal amount because of low inventory. Also on this date, the Company's Manchester LNG facility had restricted availability because one of its vaporizers was not working.[xxv]

[34] Affiliate Boston Gas is connected directly to both AGT and DOMAC, and can displace gas among the three sources through its distribution system.

- The price of propane, needed to maintain deliveries from the Company's other peaking plants, was "in the range" of spot-market prices for natural gas.[xxvi]
- TGP declared an operational flow order (OFO) for January 14, 15 and 16, which required that deliveries be within two percent of nominations.[xxvii]

In these circumstances, the Company argued that using propane and LNG to "swing" for the uncertainties of weather and the prospect of extreme cold became a reliability priority, and purchases of spot-market gas were made to meet estimated sendout requirements.[xxviii]

Liberty asked the Company why it did not buy more of the relatively inexpensive ($7.70 per MMBtu) spot-market supplies for January 13 after the under-deliveries of January 10, 11 and 12, had built up a cumulative under-delivery of 19,025 MMBtu.[xxix] The Company advised us that $7.70 did not look "cheap" on that date, and that, by that time, it was expecting an OFO on TGP soon afterwards. The Company advised that, under an OFO, it always expects to over-deliver, in order to avoid the penalties associated with under-deliveries.[xxx]

Late in that same month, ENGI over-delivered for the last five days of the month, while the Massachusetts affiliates under-delivered. Again, at least some of the over-deliveries were made with relatively expensive spot-market purchases. The Company advised that the Massachusetts affiliates under-delivered, anticipating that the pipeline's cash-out price would be an attractive source relative to the cost of spot-market supplies. The Company said that it could not use this strategy for ENGI because a fire at a hub for propane supply (Selkirk) required that the Company continue to conserve its peaking supplies to meet the swings in the weather.[xxxi]

D. Conclusions

1. The performance of the Company's on-system supplemental supplies during January, 2004 was disappointing.

The Company's 2004 IRP notes that, since ENGI's last IRP, the Company's forecasted need for on-system supplemental supplies has grown from 96,939 MMBtu in 1998/99 to an estimate of 352,700 MMBtu for the winter of 2004/05.[xxxii] And yet, when the Company needed those resources in January, 2004, their availability was severely constrained.

In the Winter 2004-2005 Cost of Gas proceeding (Docket No. DG 04-152) and then again in the course of this review, Liberty and the Staff asked the Company to explain why higher-cost spot-market supplies were acquired for ENGI during January, 2004 when the Company's peaking plants were not used to their capacity. The Company's response began as follows:

> From January 6 [2004] on, the Northeast United States experienced one of the most extreme cold snaps in decades with great uncertainty in each weather forecast as to the extent and duration of the cold. The month of January became 25% colder than normal. The extreme cold affected gas supply both by raising demand and by placing a stress on physical and mechanical components of the supply system – such as peak shaving facilities, pipeline compressors and truck

> deliveries being used at an unusually high and continuous rate. Therefore, because of the narrowing of supply options caused by the long duration of cold weather and supply-limiting incidents, because of predictions of continued unusually cold – as well as the day-to-day variability in those predictions, the Company needed to tightly manage its supplemental resources (i.e., propane and LNG) for reliability purposes. At the same time, with the cold weather causing the depletion of supplemental inventory levels, the Company purchased replacement propane supplies at a price much closer to the prices of gas in the spot market. Therefore, on several days, the Company chose to go to the spot market for a portion of its supply. Response to DR No. 2-4, Docket No. DG 04-152. (The full text of this response is attached to this chapter as Appendix I.)

The Company is quick to cite the KEDNE companies' ability to displace gas from its Massachusetts affiliates to New Hampshire, using the joint OBA on TGP, and, indeed, 52,481 MMBtu of on-system production from the Massachusetts LDCs was displaced to ENGI.[xxxiii] On the coldest days, however, when the spot gas price went as high as $54.75 per MMBtu, ENGI was over-delivering while the Massachusetts companies were under-delivering. In Liberty's experience, the failure of a peaking plant (which occurred during this time) is certainly unusual, if not unprecedented.[35] Given the Company's concerns about the scope and burden of this proceeding, Liberty did not pursue the reasons for the failure, or whether the Company has initiated its own review.

The 2004 IRP addresses contingency planning, and specifically addresses the possibility of a supply disruption at DOMAC. That contingency plan addresses a supply deficit similar to that created by the loss of DOMAC LNG supplies following the events of September 11, 2001. For its vapor requirements in that circumstance, the Company reports that it would "... engage in discussions with various service providers to meet this need in a number of ways." IRP, p. IV-25. With respect to its needs for liquid, the Company reports that it "... would immediately implement its contingency plan", which calls for liquid deliveries from various LNG facilities including (but not limited to) the NSTAR Gas facility in Hopkinton, MA; the Philadelphia Gas Works facility in Philadelphia, PA; the Transco facility in Carlstadt, NJ; and the Gaz Metropolitain facility in Montreal, PQ Canada. The Company would also call for incremental propane deliveries from its regional propane supplier as well as other suppliers in the northeast corridor. It is unclear whether this contingency plan was implemented in January, 2004, and if not, why not?

In comments on a draft of this report, Company representatives reported that their contingency planning addressed a type of contingency that is different from the ones experienced during January, 2004.[xxxiv] As we noted in the previous chapter, it is our experience that LDCs develop contingency plans for low-probability load conditions that are beyond the conditions that on-system and committed supplies are designed to handle. We did not find that ENGI had any such plans in place in January, 2004.

[35] The Company reports that two of its Massachusetts peaking facilities also experienced interruptions during this period. See the Company's response to DR No. MA 10 in this proceeding (Docket Nos. DG 04-133/DG 04-175).

2. Additional attention to operating ENGI's portfolio should yield better performance.

Liberty believes that ENGI's assets can be operated more intensively. For example, the Company reports that it tends to over-deliver during peak periods in order to avoid penalties for under-delivery. Deliveries can be set closer to system requirements by improving forecasting, however. Forecast errors are caused by imprecision in the equation for forecasting sendout, and by imprecision in the daily weather forecast. Both sources of error can be reduced by more intensive analysis. Further, neither the Company's LNG plants nor its propane plants were operated near their respective capacities during the month in question. Uncertainty cannot be completely eliminated; the effects of uncertainty can be minimized, however, by adjusting the output of these plants to match system requirements.

Detailed procedures and staffing are two areas that Liberty did not pursue because of the Company's concern about the scope of this review. These areas may bear further discussion between the Staff and the Company.

E. Recommendations

1. The Company must take a comprehensive look at the role of its peaking plants in meeting cold-weather conditions.

As noted earlier, the Company's 2004 IRP includes a "cold-snap" analysis based on "... the actual seven-day period of coldest weather experienced by the Company leading to the highest supplementals requirement." (P. IV-21) The analysis concludes that "The results of the simulation, using the SENDOUT model, showed that the Company's portfolio can meet the cold-snap requirement adequately." (P. IV-22)

Liberty observes that neither the Company's LNG plants nor its propane/air plants were operated to their respective capacities during the period in question. The Company asserts that this was because, given the anticipated extreme cold (which ultimately did not materialize at the forecasted levels), it needed to reserve the capacity of its peaking facilities for swing purposes as well as on-system reliability. Liberty also notes the Company's reports that trucking was unable to keep the plants re-supplied during that period. (Appendix I to this chapter provides additional details on these points.)

Liberty concludes that the Company must perform a realistic assessment of what it can expect from the plants as currently configured, and identify any changes to the operation, maintenance or logistics of re-supply that would be required to make them into reliable sources of supply at the time that they are needed. Such a review is especially important in view of the Company's conclusion that it cannot plan on using the Company's joint OBA on the TGP system to displace re-vaporized LNG from Massachusetts to New Hampshire because TGP may limit the Company's use of the joint OBA under peak-demand conditions. Liberty specifically recommends that additional on-site storage be considered for both types of plants.

2. Detailed contingency planning is essential.

In the previous chapter, Liberty recommended that the Company prepare a peak-period contingency plan, and file it with the Company's revised curtailment plan. Review of the events of January, 2004 show that advance planning for low-probability weather phenomena is essential, as constrained responses to such phenomena can have considerable cost consequences. We understand that the supplier's recall rights have been eliminated from the CoEnergy contract; we would like to be assured that reduced availability of ENGI's peaking plants will not cause the Company to resort to the spot market just as the price there is peaking.[36] Detailed contingency planning is the only way that these particulars can be addressed.

[36] That assurance would have at least two aspects: 1) that the plants would not suffer mechanical failures when they were needed the most, and 2) that available capacity owned by, or under contract to, the Massachusetts affiliates could be counted on for at least some back-up. It should be noted that the ability to rely on the availability of the Massachusetts resources in this manner would likely come with some attendant costs, which would need to be evaluated.

Appendix I

ENGI Response to DR No. 2-4 in Docket No. DG 04-152

DG 04-133/DG 04-175
Staff MA 1 Attachment

ENERGYNORTH NATURAL GAS, INC.
d/b/a KeySpan Energy Delivery New England
Cost of Gas (COG) Filing

DG 04-152

EnergyNorth Natural Gas, Inc.'s Responses to Staff - Set 2

Data Request Received: October 4, 2004
Request No.: Staff 2-4

Date of Response: October 14, 2004
Witness: Elizabeth Arangio

Q. Why were the higher cost spot supplies purchased on days such as 1/11, 13, 14, 27 and 28 when peak shaving wasn't maximized?

A. From January 6 on, the Northeast United States experienced one of the most extreme cold snaps in decades with great uncertainty in each weather forecast as to the extent and duration of the cold. The month of January became 25% colder than normal. The extreme cold affected gas supply both by raising demand and by placing a stress on physical and mechanical components of the supply system—such as peak shaving facilities, pipeline compressors and truck deliveries being used at an unusually high and continuous rate. Therefore, because of the narrowing of supply options caused by the long duration of cold weather and supply-limiting incidents, because of predictions of continued unusually cold—as well as the day-to-day variability in those predictions, the Company needed to tightly manage its supplemental resources (i.e., propane and LNG) for reliability purposes. At the same time, with the cold weather causing the depletion of supplemental inventory levels, the Company purchased replacement propane supplies at a price much closer to the prices of gas in the spot market. Therefore, on several days, the Company chose to go to the spot market for a portion of its supply.

I will address how these general considerations applied on each of the days in question:

January 11: On 1/9, it being a Friday, the Company had to nominate its pipeline purchases for 1/10, 1/11, and 1/12. The Northeast was already several days into the extremely cold weather. The Company was facing EDDs forecast in the low 70s with a predicted system load of approximately 110,000 MMBtus. The Company's CoEnergy contract for 20,000 MMBtus had been recalled, on 1/9 for 1/10 through 1/12. This left 65,000 MMBtus that would be supplied by EKT and DOMAC FCS. AES was forecast to be higher than spot. Concerning on-system supplementals, the DOMAC FLS 139 contract was close to being exhausted. DOMAC liquid deliveries became restricted because, as of 1/8, their tank levels were low; what they could make available for trucking was cut in half. The Company's Manchester LNG facility had restricted availability for supply because one of its vaporizer was no longer working and it was experiencing frozen fuel lines. The "7-day storage requirement," particularly with one LNG facility out, required our propane facilities to remain close to full, with use increasing the need of truck refills. The propane that had been in storage was being depleted and the tanks needed to be refilled, and that refill price would be in the range of prices on the spot market.

With all of these factors, with the need to maintain reliability, and with the predicted continued extreme cold and the variability of the forecast that had been the experience for several days, and the game plan on the morning of the 9th calling for the use of about half of the supplemental inventories, some 22,000 MMBtus, the Company needed to maintain the ability to "swing" on its supplemental resources to meet any changes in demand. With the 20,000 of CoEnergy supply recalled, the Company still had available firm pipeline capacity to transport 20,000 MMBtus of spot gas. Therefore, 20,000 of Emera spot was purchased. (The remaining supply gap would be filled by a slight imbalance on pipeline deliveries.) Now, if the cold increased above forecast, there would be supplemental supplies available to cover this, and if the weather turned warmer—since the spot purchases are firm and must be taken—the use of supplementals could be reduced and supply left in the tanks for future use. The day turned out to be warmer than forecast, and approximately 5,000 MMBtus of supplementals were used.

January 13: On the morning of the 12th, the Company was looking at forecasts at Manchester of 63 EDD for the 13th, 72 EDD for the 14th, and 84 EDD for the 15th. The associated load predicted was approximately 100,000; 115,000; and 130,000 MMBtus. The forecast therefore was to exceed design standard of 80 EDD by the 15th. DOMAC informed the Company that it was having problems vaporizing its LNG and the number of trucks available had to be restricted, as was their right under the contract. Whereas from 1/6 through 1/11 the Company had been able to go beyond its contractual share of 1 truck (2 loads) of LNG delivery per day from Transgas, and had gotten at least 7 loads per day, now the availability of Transgas trucks for transporting LNG became limited to 2 loads per day. At the Dracut delivery point due to restrictions on the MN&E pipeline, spot supplies were becoming limited. Tennessee Gas Pipeline advised that it soon would be declaring an OFO at 2% tolerance, meaning that any "swinging" on the pipeline would be eliminated. AES was still forecast to be at a high price. The 7-day storage requirement continued to be a concern. Meanwhile, 750,000 gallons of propane had been purchased to maintain the level of propane in the tanks and for continued use. That purchase price of propane was fairly comparable to the price of spot gas. So, even more so than on the 11th, the managing of propane and the use of propane and LNG in order to "swing" for the uncertainties of weather and the prospect for extreme cold, became a reliability priority, and spot purchases were made to meet sendout requirements.

January 14: On the morning of the 13th, the Company was looking at even more extreme cold. 66 EDD for that day, 74 EDD for the 14th, and 92 EDD for the 15th. The Tennessee OFO was in place. The DOMAC limitation on truck deliveries of LNG continued. There continued to be a limitation on the extra trucks available under the Transgas contract—although the Company got twice its entitlement. And now, Transgas truck drivers were facing further limitations because the recent demand had caused their activity to approach DOT limits on driver hours. AES prices continued to be high. For

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the same reasons that applied on the 11th and 13th, the propane and LNG were conserved for reliability and swing purposes by the Company purchasing in the spot market.

January 27: Selkirk, a hub for propane supply, had experienced a fire on 1/25. The fire continued on the 27th. Eastern Propane, the Company's propane supplier, advised that no trucks would deliver before 1/29, and even those deliveries were uncertain until 2/1. The Company's DOMAC FLS 142 LNG contract entitlement was depleted until 2/1; the DOMAC FLS 139 had been used up for the season. As the cold continued, Tennessee Gas Pipeline requested that KeySpan vaporize LNG in order to boost system pressure on the Tennessee gas pipeline. Furthermore, Portland Natural Gas pipeline lost a compressor station. These mounting uncertainties in the upstream gas supply market continued to support the need to conserve the use of supplementals and to purchase spot market gas.

January 28: The Selkirk problem continued; the propane market throughout New England had become restricted. AES remained too expensive. Forecasts of EDD and associated demand continued high. The weighing of these continuing uncertainties called for continued access of the spot market in order to continue to conserve the remaining, very limited, supplemental supplies.

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IV. Asset Management Agreements

A. Background

KEDNE has used an asset manager for its New Hampshire operations since acquiring ENGI in 2000. We understand that the initial use of an asset management arrangement (with El Paso Merchant Energy (*El Paso*)) was discussed during the EnergyNorth/KeySpan merger proceeding.[xxxv] In 2002, El Paso decided to exit the asset-management business. El Paso informed KEDNE of its decision to cease asset management activity in early October 2002. As a consequence, KEDNE had to replace El Paso on an expedited schedule. During October 2002, KEDNE conducted a competition for an asset-management relationship, to begin November 1, 2002, and continue only through that winter. During January and February 2003, KEDNE conducted a more conventional competition for the relationship, to begin on April 1, 2003. Entergy-Koch Trading, LP (*EKT*) won both of those competitions.

The current asset manager is Merrill Lynch Commodities, Inc. (*ML Commodities*), successor to EKT. ML Commodities assumed the relationship with ENGI when it acquired EKT in late 2004. KEDNE also uses an asset manager for its Massachusetts properties. KEDNE works with the same asset manager for both its New Hampshire and Massachusetts operations, but ENGI and KEDNE-MA have separate AMAs.

ENGI's current AMA has been in place since April 1, 2003. That AMA replaced the one that had been in effect with EKT since November 1, 2002, but which expired on March 31, 2003. The current AMA is a three-year deal, expiring on March 31, 2006.

B. Summary of Review Activities

Liberty reviewed the AMA with EKT (now ML Commodities) in light of our experience with similar agreements. Through data requests and technical conferences, Liberty explored how the Company uses the AMA in the conduct of its gas-supply operations. Liberty's project team also traveled to KEDNE's offices in Waltham, MA to observe how KEDNE interfaces with the asset manager.

As a result of our initial review and of conversations with the NHPUC Staff, Liberty was concerned about the possible consequences of certain provisions of the AMA for ENGI's gas costs. In pursuit of that concern, Liberty developed a simple dispatch model to test for the effects of those provisions. Liberty shared our results with the Staff and the Company, and participated in a technical conference to discuss the results.

As a result of that analysis, Liberty looked into the history of KEDNE's AMAs. Liberty reviewed the competitions that KEDNE conducted in October 2002 and January/February 2003.

KEDNE's AMAs provide for an annual audit by KEDNE of the results of operations under the AMA. KEDNE had an audit[37] conducted by an outside audit firm, covering the winter of 2002-2003, and the first contract year (April 1, 2003 through March 31, 2004). At KEDNE's request, Liberty reviewed the proposed scope of work, and discussed the results of the audit with the Staff and the Company. Based on that discussion and others, Liberty suggested certain changes in the AMA, pursuant to some options that are available to the Company under that agreement.

The Commission's RFP requested a cost/benefit analysis to assess whether the AMA provides a net benefit over the term of the asset-management contract. As discussed in our findings, the Company has not kept records sufficient to allow a reasonable calculation on this point. Liberty used available information to estimate the net benefits of the first year of the agreement, however.

C. Analysis/Findings

1. Initial Review of the Asset Management Agreement

Liberty's review of the Company's AMA with EKT gave us concerns in the following three areas:

- Limits imposed by the Agreement on the Company's ability to dispatch the various resources in its gas-supply portfolio on a least-cost basis;
- Pricing of gas supplied under the Agreement; and
- Provisions regarding assignment of the Company's transportation and storage contracts, and the transfer of title to the Company's gas in storage.

The latter concern arose because the AMA that was in effect when we began our review provided for assignment of all of the Company's transportation and storage assets, including its gas in storage, to the asset manager for the duration of the Agreement. Early AMAs used this structure to give the asset manager complete control over utilization of the assets.[38] The bankruptcies (or near bankruptcies) of several asset-management firms, most notably Enron and Mirant, revealed important risks in this structure, however. Assets assigned to asset managers, particularly gas in storage, became tempting targets for creditors facing compromise of their claims in bankruptcy proceedings. More recent AMAs, in our experience, tend toward an alliance structure, where the asset manager acts as the client LDC's agent, rather than taking assignment of the assets.

[37] The outside auditor was PriceWaterhouseCoopers (*PWC*). PWC refers to its assignment as "a Risk Management Assessment and an Accounting Review".
[38] Ownership of the gas in storage had to be transferred to allow the asset manager to be in compliance with the U. S. Federal Energy Regulatory Commission's (FERC's) "shipper must have title" rule.

The Company advises[xxxvi] that, prior to Liberty's review of the AMA, ENGI had already taken some steps to mitigate these risks. In an amendment to its AMA, effective April 1, 2004,[39] the parties agreed to three changes that bear on these risks:

- Article II of the Agreement was amended to provide financial guaranties of the Seller's (EKT's) obligations to Boston Gas Company in the amounts of $75 million in the months of April through November, and $20 million in the months of December through March. The Seller also agreed to maintain a Letter of Credit in the amount of $15 million throughout the Initial Term of the Agreement (The original AMA provided for a guaranty in the amount of $20,000,000.);[40]
- Article V, regarding assignment of ENGI's gas-supply assets was amended to provide more clearly for transfer of the assets back to ENGI in the event of asset-manager default, or of termination or expiration of the contract.
- Merrill Lynch & Company, Inc., parent of ML Commodities, replaced EKT as guarantor for the Seller's obligations under the AMA.

These changes do not eliminate the risks of the assignment structure, in our view, but have clearly reduced them, relative to what they were before the changes were made.

Limits on Dispatch

The AMA with EKT (now ML Commodities) provides for pricing the gas that the asset manager delivers to ENGI pursuant to dispatch "tiers". The dispatch limits come into play in determining the quantities that the Company receives at each price. The AMA provides that western Canadian supply will be used first; then base-load supply from two areas, the production area where the Company's transportation entitlements originate (the Gulf Coast producing area)and the interconnect with eastern Canadian sources of supply at Dracut, MA; then swing supply from those same two areas; then storage gas.

The gas is delivered to the Company's city gates each day from whatever sources that the asset manager elects to use on that day, but pricing must be in accordance with the agreed-upon tiers. The purpose of the tiers is to determine the price that the Company is charged for the gas that is delivered, as each tier has a different price. The exception to this general rule is storage gas. The AMA specifies storage's place in the dispatch order, just as it does for the other sources. The total quantity of gas priced as storage gas is fixed, however, limited to the capacity of the storage facilities assigned to the asset manager.

One area in particular that we examined is one of ENGI's contracts with Distrigas of Massachusetts (DOMAC). The contract is for firm combination service (FCS), meaning that it can be delivered to ENGI either as liquid or as a vapor. The annual contract quantity is available over each contract year (November 1-October 31 of the following year) and is equal to 151 times

[39] The amendment was signed in late October 2004, but was made effective April 1, 2004. See the Company's response to DR No. 1-43 in Docket No. DG 04-133/DG 04-175.
[40] The limits on this guarantee were removed when ML Commodities closed on its purchase of EKT. See the Company's response to DR No. 1-43 in this proceeding.

the MDQ. The commodity price for gas under this contract has historically been determined on a "look-back" basis, where the price is based on certain prices for natural gas the previous year.[41]

The DOMAC FCS volumes generally are not included in the resources to be operated by the asset manager under the AMA.[42] Under the terms of the AMA, the DOMAC FCS volumes cannot be dispatched on any given day until all sources of flowing gas and gas in storage have already been dispatched. Thus, even though the DOMAC FCS volumes have been attractively priced in recent years, they cannot be used until all flowing and storage gas have been dispatched.

Liberty understands that the Company argued strongly that for reliability reasons the DOMAC supply should be held outside the tiered pricing structure of the AMA in order to give the Company the flexibility to use that supply as a liquid if needed.[43] This limit on access to the DOMAC FCS supplies has been a source of considerable controversy before the NHPUC. It was explored in considerable detail in Docket No. DG 03-160, which was ultimately settled.[44]

Liberty used a simple spreadsheet-based computer model of ENGI's dispatch to test for possible effects of the limits on dispatch. In the Winter 2004-2005 Cost of Gas proceeding (Docket No. DG 04-152), the Company provided information on recent sendout[xxxvii] and on weather.[xxxviii] Liberty performed regression analysis on the weather and sendout for 2003-2004 to develop base and use factors for ENGI's load during that period. We then used weather data also provided by the Company[xxxix] to "drive" the dispatch model to see whether the limits on dispatch had any effect; *i.e.*, whether dispatch would have been different if the limits had not been in place.

Our analysis found that, indeed, the AMA's constraints on dispatch are binding, and that they can have adverse consequences for ENGI's customers under certain circumstances. The dispatch constraints are not a problem if the weather is normal, but they cause increased costs under certain weather conditions.

The problem occurs when the Company's gas in market-area storage has been depleted, but daily sendout is in a range where the dispatch restrictions in the AMA prevent the Company from using the supplies available under its FCS contract. In that circumstance, the Company must either buy spot-market gas, or gas that it has used to refill storage. Since any gas used to refill storage would have been bought after the end of the storage-injection season, either that gas or any spot-market gas would likely be more expensive than the DOMAC supply, since the DOMAC supply has been priced as though it had been purchased the prior year. The difference between the price of the DOMAC supply and the price of the spot-market gas or storage-refill

[41] This contract expires at the end of October, 2005. DOMAC has informed the Company that it will continue to offer the FCS service, but that the service will be priced in a different way.

[42] The DOMAC contract and other behind-the-city-gate resources are shared with the asset manager under certain circumstances. Those circumstances are covered in Sections 4.1 and 4.2 of the AMA.

[43] The Company's reasoning on this point is presented on p. IV-13 of the IRP.

[44] *See* Order No. 24,323, "Order Approving Settlement Agreement", issued in Docket No. DG 03-160 on May 7, 2004.

gas, times the volume of spot-market gas or storage-refill gas that must be bought in this circumstance, is a measure of the harm that the dispatch restriction causes to ENGI's customers.

Our analysis using the dispatch model found that the constraints on access to the DOMAC supply would have changed the optimal gas-supply resource mix in eight of the 23 years for which the Company provided weather data (1981/82 through 2003/04). The constraint limits access to the DOMAC supply when weather conditions involve a winter with sustained cold. 2002/2003 was such a winter, but 2003/2004 was not. January 2004 included some of the coldest weather on record; overall, however, that winter was approximately normal in terms of the number of degree-days experienced. With that weather pattern, stored volumes were available throughout the winter, so the constraint on access to the DOMAC volumes had no consequences for ENGI's customers. Some very expensive spot-market gas had to be acquired during January of 2004, but that gas was acquired <u>in addition to</u> the DOMAC supply, rather than in place of it.

2002/2003, on the other hand, was a colder-than-normal winter. In that year, storage was depleted but the Company did not have access to the DOMAC volumes in the range of sendout where the Company could have used the DOMAC gas to substitute for storage gas (sendout between 49,718 and 77,833 MMBtu/day). We did not attempt to estimate by how much costs to ENGI's customers were increased by the restriction during that year, since the Commission's Staff and the Company had settled the issue of consequences for ENGI's customers in Docket No. DG 03-160.

The table below lists the years for which, based on our model, the weather would have caused the dispatch restrictions to be binding. The result is that, for the load that ENGI had in 2003-2004, the dispatch restrictions would have caused the Company to purchase the indicated amounts of spot-market or storage-refill gas, in place of available DOMAC volumes. As noted above, the harm to ENGI's customers in each case would be the volume of extra purchases, times the difference between the price paid for the extra spot-market gas and the price of the DOMAC volumes.[45]

[45] The Company points out that the data in the table does not factor in the benefits that the Company argues accrue from the AMA.

Table IV-1
Impact of Dispatch Restrictions

Weather Year (May 1-April 30)	Additional "Spot" Purchases (MMBtu)
1981-82	404,136
1985-86	35,297
1986-87	212,250
1989-90	20,979
1992-93	497,053
1993-94	79,343
2000-01	694,273
2002-03	954,699

Source: Liberty calculations

Pricing of Gas Supplied Under the Agreement

We also have concerns regarding the price of the gas supplied in each tier under the AMA. The Company confirmed[xl] that the Tier 3 gas supplied under the agreement is priced at a weighted average of the price indexes listed for the supplies in that tier. The monthly indexes are used for base-load prices, and the daily indexes are used for pricing swing gas. The indexes are weighted by the maximum daily quantities in the transportation contracts that the Company has released to the asset manager.

In other areas of the country, this averaging process increases the direct cost of the gas supplied because the weighting factors are different from those that would result from an LDC dispatching its own supplies. When LDCs conduct the gas-supply function for themselves, they generally use a process known as "least-cost dispatch". In this process, an LDC will satisfy its requirements with its lowest-cost source of supply first, then switch to its second-lowest-cost source, and so on.

Supply sources are evaluated and compared on the basis of costs delivered to the city gate; *i.e.*, purchase-point price, plus the cost of pipeline fuel and the variable transportation costs incurred in moving the gas from the purchase point to the city gate. Referring to the data in the Appendixes 1 in the AMA with ML Commodities, if the Company needed a base-load quantity of gas, it would examine the city-gate cost of gas that could be bought at each of the five receipt points in its transportation contracts with TGP – Zone 0, 100 Leg; Zone 1, 100, 500 and 800 Legs; and Dracut – and buy them in the order of increasing delivered cost – lowest-cost one first, second-lowest-cost one second, etc. – until it had satisfied its requirement. The average cost of the quantity bought would be the cost of each one bought, weighted by the quantity of each one actually taken.

The weighted-average-of-indexes process gives a different result. Each MMBtu delivered is priced as though it came from all of the pipeline receipt points, in proportion to ENGI's transportation entitlements from each point.[46] Using the TGP receipt-point entitlements data in the Appendixes 1, each peak-period MMBtu supplied in Tier 3 would be priced as though it had been acquired in the following proportions:

Table IV-2
Weighting by TGP Receipt-Point Entitlements

Receipt Point	MDQ	Proportion (%)
Zone 0, 100 Leg	7,035	17
Zone 1, 100 Leg	523	1
Zone 1, 500 Leg	9,502	23
Zone 1, 800 Leg	4,536	11
Dracut	20,000	48

Source: AMA, Appendix 1; Liberty calculations

Liberty's experience in other areas of the country is that gas priced on the basis of the weighted average of indexes costs the LDC more than gas acquired through least-cost dispatch. The Company advised us[xli] that it "watches" the city-gate (delivered) costs of gas sourced from the different locations, and finds that there is little difference among them. The Company asserted that the use of pricing based on an average of the indexes for a utility in ENGI's position would not result in increased gas costs.[xlii] The Company has not performed a formal analysis to demonstrate this conclusion, however, and we remain concerned that, if the AMA is to remain in place in the future, such a pricing mechanism should be carefully examined.

2. Award of the Asset-Management Contract

Liberty presented the results of our dispatch analysis to the Company in a technical conference on December 14, 2004. Liberty also provided our dispatch model and all calculations to the Company in response to a data request submitted in this proceeding. Liberty solicited any comments on or criticisms of the analysis that the Company might have. The Company indicated that, while it has significant concerns regarding the analysis performed by Liberty, because the parties expect to reach a settlement in this docket (particularly regarding management of the gas supply portfolio going forward), it would not be fruitful to examine those concerns in more detail.[xliii]

As noted above, our analysis found that the dispatch restrictions and gas-pricing provisions could cause harm to ENGI's customers. Accordingly, Liberty looked into why the Company would have accepted theseprovisions, and whether the Company had evaluated the potential for harm prior to accepting them.

The current AMA was awarded through a competition held in January and February, 2003. The Request for Proposals (RFP) for that competition was issued on behalf of all four of the KEDNE

[46] The role of the Company's Dracut capacity in this process is not clear. The AMA refers to the production-area TGP receipt points (only) for pricing off-peak gas, but all receipt points for on-peak gas. (See the Definitions section of the AMA, especially p. 5.)

companies, Boston Gas Company, Colonial Gas Company, Essex Gas Company and ENGI.[xliv] The RFP expressed interest in "... a contractual alliance ... to assist KED-NE in managing its energy assets." RFP, p. 2. The nature of the relationship sought was described as follows:

1. Bidder will assist KED-NE in developing and implementing strategies to enhance the utilization and value of the Massachusetts and New Hampshire natural gas portfolios.
2. ...
3. KED-NE and Bidder will each have two representatives on a Joint Oversight Committee ("JOC") which will set strategies and provide oversight of transactions managed by KED-NE. The JOC will also establish a platform for growth and will meet quarterly to monitor performance, discuss strategies, resolve disputes and identify issues.
4. KED-NE will manage and maintain control of all gas assets and gas contracts. Bidder will have no rights to utilize the gas assets or gas contracts on its own behalf.
5. Bidder will not have any exclusive rights to sell KED-NE gas supplies. KED-NE is required to procure its gas supplies on a least-cost, reliable basis. RFP, p. 3 (emphasis added).

Other documents provided to Liberty[xlv] report that KEDNE's New York affiliates have an alliance arrangement with a major producer of natural gas (Coral Energy). Liberty assumes that the relationship described in the RFP was modeled after the one that the New York affiliates have with Coral.

The RFP was sent to seven bidders. Three elected not to bid. Of the four that bid, three submitted proposals that were responsive to the RFP, one did not. Rather than submitting a proposal for an alliance, EKT proposed to continue the asset-management structure that was already in place. EKT's proposal provided for a review of the results of the asset-management structure after one year[47] (the RFP was for a three-year relationship), however, at which point KED-NE could elect to an alliance structure "... consistent with Seller's RFP response dated January 22, 2003 ..." Amended and Restated Gas Resource Portfolio Management and Gas Sales Agreement between EnergyNorth Natural Gas, Inc. and Entergy-Koch Trading, LP, p. 17.

The Company selected EKT. The Company advised us that KEDNE's willingness to accept a non-conforming proposal from EKT arose in part from its ongoing relationship with EKT.[xlvi] Thus, Liberty reviewed the earlier competition when EKT replaced El Paso Merchant Energy. As noted in the Background section of this chapter, El Paso was KEDNE's asset manager from November 1, 1999 through October 31, 2002. ENGI was added to this arrangement when it was acquired by KeySpan in November, 2000.

KEDNE had to conduct an expedited competition to replace El Paso in October, 2002. As noted earlier, it had been the Company's intention to continue the relationship with El Paso, but credit problems forced El Paso to withdraw from the asset management business.[xlvii] The RFP for that competition, dated October 9, 2002, contemplated "a portfolio management arrangement", rather

[47] The 2004 Amendment to the AMA deferred this choice to the end of the second contract year, March 31, 2005.

than an alliance, but bidders were encouraged to discuss alternative arrangements if they

The RFP was sent to four new bidders, and to Coral Energy Holding, with whom KeySpan New York had an ongoing alliance arrangement. Coral proposed extension of its alliance arrangement to include the New England affiliates. The other four bidders proposed asset-management arrangements. EKT was one of the four, and was selected.

The materials[xlix] provided by the Company that describe its evaluation process list five criteria for the selection:

1. Financial qualifications
2. Operational qualifications
3. Value of the contract
4. Trading capabilities
5. Ability to work the transaction through the regulatory process.

Those evaluation materials mentioned "operational concerns" with one of the proposals (not EKT's), but essentially focused on the size of the asset-management fee payment (Criterion 3). Those materials also mentioned that the Company could not conduct the supply function itself (*i.e.*, without the assistance of an asset manager) because of staff reductions.[48]

In none of the decision-support materials for either competition – the one conducted in January and February of 2003, or the prior one conducted in October 2002 – did Liberty find any mention of potential exposure of KEDNE's customers to higher gas costs due to restrictions on dispatch or to any other aspect of the proposed arrangements.

3. Cost/Benefit Analysis

As noted earlier, the Commission's RFP requested that the consultant perform a cost/benefit analysis to assess whether the current AMA provides a net benefit over the term of the contract. As Liberty stated in our proposal to the Commission, in our experience most LDCs who use asset managers perform some type of "shadow" dispatch, where the Company simulates what its gas costs would have been if it had conducted the gas-supply function itself. Those costs are then compared to gas costs under the AMA to provide a measure of the benefits of the AMA.

ENGI does not perform a shadow dispatch. In fact, as noted in the chapter on dispatch and balancing, the Company conducts dispatch pursuant to the rules of the AMA. The tier structure in the AMA, not current prices, drives dispatch. Liberty found little evidence that ENGI has tried to assess whether the arrangements under the AMA are producing any net benefits.[49]

[48] In comments on a draft of this report, the Company reminded us that this concern related to all of the KEDNE LDCs together, not just ENGI. See, *e.g.*, testimony by E. Arangio at Tr. 12/22/03, pp. 72-74.

[49] The only evidence we found of any estimates on this point was in Ms. Arangio's Prefiled Rebuttal Testimony in Docket No. DG 03-160. In that testimony, she asserts that the AMA with EKT produced a net benefit for ENGI's customers in excess of $2.8 million for the period November, 2002 through March, 2003.

Liberty tried to develop its own estimate of the benefits of the AMA. When this estimate was prepared, only the first contract year (2003-2004) was complete, so only for that year could net benefits be estimated.

Attachment 4-1 to the Company's response to DR No. 04-01 in Docket No. DG 04-040 provides EKT's statement of profits to be shared between EKT and ENGI for the first full contract year (April 1, 2003 through March 31, 2004). ENGI's share of the profits are composed of two parts--a share of the total profits generated under EKT's AMAs with the KEDNE companies, plus an additional share of the profits generated in transactions (typically off-system sales) using the gas made available to EKT by ENGI from resources that are not part of the AMA.[50] (The sharing percentages are confidential, and therefore they are not included in this report.) ENGI's totals were $587,195 for its share of margins generated by EKT using all resources assigned by the KEDNE companies, plus $252,031 from extra resources made available to EKT by ENGI, for a total of $839,226.

ENGI's response to Data Request No. 1-1 in Docket No. DG 04-040 reports that ENGI had EKT sell off-system most of the gas that remained available under the DOMAC FCS contract at the end of the winter of 2002-2003. 224,000 MMBtu was sold off-system, and 47,993 MMBtu remained available under the contract but was not used. The commodity price of that gas was $2.8749 per MMBtu. The same response shows that the average price of spot-market gas that summer was $6.8722 per MMBtu.

Liberty observes that ENGI conducted off-system sales for its own account prior to its acquisition by KEDNE. All of the margins from those sales were credited to ENGI's purchased-gas costs, rather than half of those margins, as is the case under the EKT Agreement. Liberty understands that ENGI's margins from off-system sales were generally in the range of $100,000 to $200,000 per year;[li] at that time, however, the difference between ENGI's gas cost and the price available through off-system sales was rather less than the $4 per MMBtu difference between the value of the gas in the market and the cost of the gas available under the DOMAC contract. (The Company has indicated[lii] that the $100,000-to-$200,000 figure is higher than was actually experienced in recent years. Because the parties in this proceeding have reached a resolution of the issues in the case, we did not seek to review the Commission's or the Company's records to determine the correct amount.)

With the larger difference between gas cost and its value in off-system sales, margins from off-system sales could have been as high as $1.1 million ($4 per MMBtu, times 224,000 actually sold off-system, plus 47,993 MMBtu available but not sold, equals $1.1 million). EKT's margins from selling this gas were $504,062, but EKT was not given all of the available gas to sell. For the purpose of this estimate, Liberty assumes that ENGI could have made the same margin per MMBtu that EKT did[51], but that ENGI would have sold the entire quantity of leftover DOMAC FCS gas, rather than most of it. In that event, ENGI's off-system sales margins would have been $612,060. As noted above, ENGI's total proceeds under the EKT Agreement were

[50] These transactions are covered by Sections 4.1 and 4.2 of the AMA.
[51] In comments on a draft of this report, the Company disputes this assumption.

$839,226. Thus, Liberty estimates that the maximum net benefit that the Agreement could have produced in its first year was $227,166 ($839,226 minus $612,060).

Liberty's dispatch analysis showed no increase in gas costs through the winter of 2003-2004 due to the dispatch constraints. Thus, Liberty's net-benefit estimate does not have to be reduced for extra gas costs from that source during the winter of 2003-2004. The Company has argued that the AMA with EKT has an extra benefit in that the gas provided to the KEDNE companies under the Agreement is priced at index, rather than at a premium to index. Liberty observes that most AMAs today with client companies of any size provide for "flat-index" pricing. Indeed, all four of the asset-management proposals to the Company in October 2002 provided for flat-index pricing. Moreover, Liberty believes that, if the KEDNE companies bought gas together, they would have enough buying power to command flat-index pricing even outside the context of an AMA. Thus, Liberty did not increase its net-benefits estimate for flat-index pricing.

As noted earlier, Liberty's experience with other AMAs suggests that the use of weighted averages of indexes to determine the gas price, rather than least-cost dispatch, has the effect of increasing commodity costs to the LDC. We suspect that is the case here. Without access to the history of price indexes, or an opportunity to simulate least-cost dispatch, we are unable to estimate how much that cost increase might be or whether in fact there would have been a cost differential.[52] Any such increase would have to be netted against the benefit figure estimated above, and could turn the net benefits from positive to negative in a given year.

D. Conclusions

1. ENGI's continued use of an asset-management-type relationship would be imprudent.

Liberty can understand why an asset-management-type proposal was selected in October, 2002:

- ENGI's relationship with El Paso had been of this type, complete with tiered dispatch;
- ENGI's RFP and four of the five proposals that it received were of this type.

ENGI clearly had other alternatives in the spring of 2003, however, yet it chose to retain the asset-management type for at least another year.

As part of our data requests in this proceeding, Liberty requested all of the decision-support materials for both competitions. None of that material showed any thought given to – much less any analysis of – whether any aspect of the proposed relationships posed any risks of higher gas costs to ENGI's customers.

[52] The Company reported that it asked ML Commodities whether the weighted-average-of-indexes mechanism causes an increase to ENGI's commodity costs, and the answer was "minimal, if anything". Conference call, April 5, 2005.

Liberty's experience is that EKT often proposes higher asset-management-fee payments than competitors, but that the higher payment comes with more-severe restrictions on dispatch.[53] In Liberty's experience, bid evaluations that include EKT as a competitor generally begin with an assessment of what risks are posed to gas customers if EKT's restrictions on dispatch are accepted. Liberty's understanding is that EKT is generally willing to adjust its proposed constraints on dispatch (in return for a reduced asset-management fee), but the asset-management client would have to seek negotiations on this point. We could not find any evidence that KEDNE identified the dispatch restrictions as a concern. Thus, KEDNE advised[liii] us that it never sought any negotiations with EKT on this point. Prior to selecting EKT in the spring of 2003, ENGI should have assessed those risks.

As we stated in our testimony to the NHPUC in January of this year, our analysis suggests that the weather pattern experienced in the winter of 2003-2004 was one of the 15 years out of the last 23 for which the dispatch restrictions did not cause premature depletion of storage gas. Moreover, after the controversy over access to the DOMAC volumes that took place in Docket No. DG 03-160, the restrictions on access to that gas were eased somewhat.[54] Thus, for contract year 2003-2004, the dispatch restrictions in the AMA appear to have had no consequences for ENGI's customers.

The weighted-average-of-indexes mechanism is another matter. Based on our experience, this mechanism always increases costs. We are concerned that the Company has made no formal attempt to evaluate the potential impact of this pricing mechanism, and believe it should do so if the mechanism is going to continue to be used in the future.

2. ENGI has insufficient information to know whether the current asset-management relationship is providing a net benefit to its customers.

ENGI knows how much the guaranteed asset-management-fee payment from ML Commodities is, and ENGI gets a statement from ML Commodities presenting the results of ML Commodities' computation of ENGI's share of the profits of the asset-management relationship. ENGI has not received a detailed accounting of how ML Commodities' numbers are calculated, however, and has an insufficient basis to determine whether the asset-management arrangement is causing increases in other costs that offset, or even more than offset, the benefit realized from its share of the profits of the arrangement. Although ENGI engaged its independent accountant to conduct a review of the basis for the profit-sharing amounts paid by ML Commodities, we believe that better ongoing reporting is necessary if the relationship with ML Commodities is to remain in place.

[53] In comments on a draft of this report, the Company reported that it was primarily the Company's willingness to agree to the dispatch restrictions that generated the value derived from the AMA.

[54] The Company reported that, for the winter of 2003-2004, EKT allowed the Company to dispatch the DOMAC FCS supply on days when doing so did not affect any strategies of EKT. See the Company's response to DR No. 2-1 in Docket No. DG 04-152.

E. Recommendations

1. ENGI should exercise its option under the current AMA to convert the relationship to the alliance structure.

Liberty is not opposed to LDCs working with asset managers. Rather, it is the nature of ENGI's relationship with ML Commodities that is the problem. ENGI has an option under the current contract to negotiate an alliance form, and Liberty believes that the Company should take that option. This recommendation has already been discussed with the Company, and the Company has negotiated an acceptable amendment to its relationship with ML Commodities.

2. ENGI should re-compete its asset-management relationship at the end of the current contract if it determines to continue using an asset manager.

As noted earlier, Liberty believes that asset-management relationships have moved, and are continuing to move, in the direction of alliances, rather than asset-transfers. At the end of the current contract (March 31, 2006), ENGI should re-compete its asset-management relationship, to get its asset-management relationship in line with this trend if it determines to continue using an outside asset manager.

3. ENGI must begin to measure the benefits of its asset-management relationship.

To know whether the relationship is providing a net benefit, the Company must develop an estimate of what its gas costs would be without the relationship, for comparison with its gas costs with the relationship. Liberty knows no way to do this other than with some type of "shadow" dispatch: what resources would the Company have used each day if it were operating its own gas-supply function, and what would those resources have cost? Also, what level of off-system sales margins would the Company have realized if it were conducting its own secondary-market program? Hopefully, the asset manager would deliver greater margins than the Company would achieve on its own; the Company would have realized something from this activity, however, and all of that benefit would have gone to its customers. Some allowance must be made for this activity if the Company is to develop a true sense of the benefits of the AMA.

V. Recommendations for Further Study

As noted in the Introduction to this report, and in our discussion of the Company's short-term planning (Chapter III), there were several subjects that we encountered that warranted additional investigation, in our view. Those subjects were not pursued at the time they were encountered due to the Company's expressed concerns about the scope of this review, and about the associated burdens on Company personnel. We have discussed these areas with the Commission's Staff because many of them provide opportunities for improved planning or otherwise bear further discussion. Our purpose in discussing them here is to help the Staff and the Company focus their further efforts in these areas by recording key questions that are not answered to our satisfaction.

A. Planning for the Peak

The Liberty Team confesses to some confusion about ENGI's planning for dealing with peak-load conditions. Our frame of reference is the approach to that planning that is most familiar to us. That approach relies on the following parts:

- A supply-capacity portfolio, composed of owned and committed capacity resources, sufficient to provide supply to firm customers at a 95- to 97-percent confidence level; *i.e.*, capacity sufficient to provide supply under load conditions with a probability of occurrence greater than three to five percent. Where within that range the LDC decides to stop adding committed resources is based on some type of present-value analysis of the cost of incremental committed resources versus the expected cost of supplemental (spot-market) resources, acquired under peak-load conditions.
- A complementary peak-period supply plan, or contingency plan, that addresses how the Company will provide supply to non-curtailable customers under load conditions <u>not</u> provided for by the owned or committed capacity portfolio; *i.e.*, load conditions with a probability of occurrence of less than three to five percent.
- A coordinated curtailment plan that identifies firm customers that would be curtailed under those extreme load conditions.

In our experience, not every LDC's planning has three parts, separately identified and labeled in this manner. In our experience, however, this approach to serving firm customers under peak load conditions is the most cost-effective; thus, our assessments focus on whether extant plans and procedures would support implementation of this approach.

On the basis of the Company's IRP and the various materials to which we have had access in the course of this investigation, we could not conclude that ENGI's planning is adequate in this area. What we think we understand about the Company's planning is the following:

1. ENGI uses a cost-benefit analysis, denominated in terms of the estimated benefit of avoiding curtailment of an average firm customer, to determine the design criteria for its capacity portfolio.

2. The Company's design criteria are estimated by the Company to have a 2.14 percent probability of occurrence in the case of the peak-day criterion (80 EDD), and 2.67 percent in the case of the annual criterion (7,870 EDD). These probabilities are based on a normal probability distribution of 20 years of EDD data for the Manchester, New Hampshire weather station.
3. The Company then assembles a capacity portfolio that would supply almost all of its firm customers under the indicated conditions at the lowest overall cost.

Thus, the Company would seem to be designing its owned and committed resource portfolio to a more-rigorous standard than is common in our experience: 2.14 percent probability of occurrence, versus our three to five percent probability.

Our analysis of the available weather data suggests that the Company's design criteria have a higher probability of occurrence than the Company's analysis suggests: 4.25 percent probability for the design day, rather than the Company's 2.14 percent. Thus, our analysis suggests that a design day (80 EDD) is twice as likely to occur as the Company's analysis says that it is. In fact, it would appear that the Company has experienced two quite significant weather events in the last five years,[55] so the disparity in the probability of occurrence is troubling.

We could find no supply plan for conditions more severe than the Company's design day. The Company's peaking plants are counted as supply resources at levels below their name-plate capacities, however,[56] so we assume that those plants could be operated closer to capacity if necessary. Regarding the other piece of the plans complex that we look for, the Company reported that its curtailment plan was being revised at the time that it was requested for this analysis; thus, it was not provided.

In the time and budget that we had available, the Liberty Team was unable to satisfy ourselves that the Company's planning for these extreme load conditions is adequate. As the Commission's Staff and the Company work together to address our findings, this planning should be considered a priority.

B. What If Things Go Wrong?

As discussed in Chapter III, the performance of the Company's on-system supplemental supplies during the extreme cold of January, 2004, including arrangements for re-supplying them, was disappointing. We expect that the Company will have undertaken a very careful review of the performance of its gas-supply systems during that period, and we hope that the Company will share the results of that review with the Commission's Staff. ENGI's customers ended up paying for some very expensive spot-market purchases during that period, and the Commission needs to be assured going forward that all possible measures have been taken a) to ensure that the Company's owned and committed resources perform better than they did in January, 2004 if

[55] January, 2000 and January, 2004.
[56] See Chart IV-D-3, pp. IV-37 in the IRP.

those weather conditions recur, and b) to minimize the cost consequences of failures in systems and equipment in the event that they recur.

The Liberty Team, plus a member of the Commission's Staff, reviewed some records from that period during our visit to the Company's offices in December, 2004. Our review confirmed the frightening nature of the weather forecasts that the Company was facing early in the week of January 12, 2004. The areas that require additional study are a) the performance of the Company's supply resources during that period, and b) contingency planning for when some of those resources fail, as they did then.

At the conclusion of our discussions at the Company's offices in Massachusetts, the Liberty Team had been hopeful that the joint operational balancing agreement (OBA) on the Tennessee Gas Pipeline (TGP) system might allow the Company to displace re-vaporized LNG from the Company's LNG facilities in Massachusetts into New Hampshire as a way of backing up ENGI's peak-period supply resources. In comments on a draft of this report,[liv] however, the Company advised that the joint OBA cannot be counted on under peak load conditions because TGP can rescind it under those conditions.

As noted in Chapter III, the Company's IRP has a section on contingency planning. As also noted there, however, the Company conceded that the contingencies addressed in that section do not include the failures of in-place supply arrangements and resources that characterized the January, 2004 period. Liberty observes that some of the measures identified in that section might have been useful in the January, 2004 circumstances, and Liberty urges the Company and the Staff to examine the various measures carefully in the course of their review.

Liberty observes that some States have emergency-sharing programs to address the kinds of contingencies experienced by the Company during January, 2004. In other places, groups of LDCs have joined together to develop resource-sharing programs to address those kinds of contingencies. Liberty recommends that the Company and the Staff consider some such emergency-sharing measures as an outcome of their review of the events of that period.

C. Conduct of the Gas-Supply Function

Liberty also has some general concerns about the conduct of the gas-supply function at ENGI, in the following areas:

- Administration of the AMA;
- Role of the Company's peaking plants in meeting high-demand load conditions; and
- Relationship between costs and rates.

Each of these areas is addressed in turn.

1. Administration of the AMA

In Chapter IV of this report, we reported our concerns about aspects of the AMA with EKT (now ML Commodities). The focus here is on ENGI's conduct of its responsibilities under the AMA.

As also reported in Chapter IV, ENGI and its Massachusetts affiliates have separate agreements with ML Commodities. Those agreements are administered together, however, by KEDNE's Gas Supply group at the Company's headquarters in Waltham, MA. Our understanding is that most physical aspects of the relationship, such things as nominations of quantities to the asset manager and timely deliveries by the asset manager to the Company's city gates, run smoothly.

The economic aspects of the relationship is the area of concern. KEDNE receives an annual report from the asset manager regarding the amount of profit generated by the relationship. The annual profit report contains very little information regarding the components of the reported profit information, and no back-up for those figures is provided. KEDNE's approach to this aspect of the AMA has been to send an audit firm to the asset manager's offices once per year to determine whether the asset manager is complying with the terms of the agreement.

Liberty has considerable experience with performance evaluation under asset-management agreements. It is Liberty's opinion that, without some understanding of how value is created under an AMA, LDC personnel are unable to evaluate whether the agreement is providing a net benefit. No doubt the KEDNE agreements are producing the profits (as defined in those agreements) that are being reported by KEDNE and that were verified by KEDNE's auditor; unanswered questions include the following:

- Whether the agreements are increasing costs in ways and amounts that more than offset the profits being reported under the agreements;
- Whether the activities that are generating the reported profits could be conducted by someone else (such as the LDC itself) in ways that would result in lower costs to utility customers;
- Whether the activities being conducted are exposing utility customers to inappropriate risks.

Liberty recommends that, if the Company continues with an asset-management relationship, the Company and the NH PUC Staff work together to understand how value is created under the agreements, and to address the questions identified above.

2. Role of the Company's Peaking Plants

On several occasions, Company personnel advised the Liberty Team and the Commission Staff that, when load conditions are such that the pipeline issues an operational flow order (OFO), the Company plans to over-deliver from its pipeline and storage resources in order to ensure that it does not incur the penalties associated with under-deliveries. Liberty certainly understands the Company's desire to avoid penalties for under-delivery; the question is whether over-delivery is necessary to provide that assurance, and whether that same level of assurance is attainable at lower cost in other ways.

Liberty observes that the sendout capacity of ENGI's peaking plants is reported by the Company as 57,400 Dth/day, or 43 percent of its design-day sendout for the winter of 2004/2005.[57] Delivery tolerances under OFO conditions drop to two percent of contract quantities, or 1,030 Dth/day for pipeline deliveries, and 562 Dth/day for deliveries from storage. Thus, it would seem that there is plenty of capacity in the Company's peaking plants to adjust sendout upward if load conditions exceed the forecast (which is the circumstance in which under-deliveries might occur). Moreover, the Company usually has much more ability to adjust the output of its peaking plants than it does with pipeline or storage supplies, which generally must be nominated the day before the gas is to flow.

The complicating factor for ENGI's peaking plants is the very limited on-site storage at those plants. It is possible that, as was the case in January, 2004, the spot-market costs of incremental quantities of peaking fuels is very nearly the same as that of incremental quantities of pipeline gas. Thus, nothing would be saved by meeting the peak with peaking plants, rather than pipeline supply. Liberty views this as another area of unanswered questions, to be addressed in further studies by the Company and the Commission's Staff, including studying the possibility of increased storage at the peaking plants.

3. The Costs of Conducting the Gas-Supply Function

Liberty has some concern that the way ENGI is being operated today does not line up with the structure of its rates and charges. Our concern is that ENGI's rate structure may no longer reflect the costs that the Company incurs in conducting its business.

Consider the costs of conducting the gas-supply function. When the Company conducted that function for itself, it incurred the costs of personnel and systems required to conduct the function. Those costs are presumably reflected in the rates that the Company is authorized to charge its customers. Liberty understands that ENGI has an allowance for "indirect" gas costs, to cover items like operation and maintenance of its peaking plants. If the roles of those plants in meeting the Company's need for supplies has changed, then the allowance for recovery of those costs that is in the Company's indirect gas costs may not reflect the costs that the Company is incurring.

The Commission needs to have a better understanding of how the gas-supply function is being conducted. This is another area where the Company and the Commission's Staff should work to improve the Commission's understanding.

[57] Sendout capacity of the plants is from Chart IV-C-2, p. 2 of 4 at p. IV-30 of the IRP; peak-day sendout capacity is from Chart IV-D-3 at p. IV-37 of the IRP.