III. FORECAST METHODOLOGY

A. Introduction

EnergyNorth developed its five-year forecast of customer requirements under design weather planning conditions using the following process:

1. Forecast Incremental Sendout

   Incremental sendout is the additional sendout that EnergyNorth forecasts to occur over the five-year forecast period above the level established for an identified actual reference year, which was 2005/06 for purposes of this plan.[1] The Company used econometric models to develop a forecast of incremental sendout for traditional markets (i.e., residential, and commercial and industrial customers). Incremental sendout forecasts of non-traditional markets, such as natural-gas vehicles ("NGVs") and large-scale power generation, and demand-side management savings ("DSM") were developed outside of the econometric models because the sendout associated with these markets is not included in the historical data used to develop the econometric equations. Forecasts of incremental sendout for traditional and non-traditional markets were summed and reductions from DSM were subtracted to determine the total incremental sendout over the forecast period.

2. Develop Reference Year Sendout Using Regression Equations

   The Company then developed the reference year sendout using regression equations. The level of EnergyNorth's sendout in the 2005/06 reference year served as the "springboard" to which incremental sendout was added. The actual sendout data used for the springboard are a function of the weather conditions experienced in the reference year. Therefore, the Company uses regression equations to normalize the sendout in the reference year based on normalized weather data.

3. Normalize Forecast of Customer Requirements

   The Company summed the incremental sendout requirements with the weather-normalized springboard sendout requirements to determine EnergyNorth's total normalized forecast of customer requirements over the five-year forecast period.

[1] The reference year is the split year May 1, 2005 through April 30, 2006.

4. Determine Design Weather Planning Standards

EnergyNorth performed a cost-benefit analysis to determine the appropriate design day and design year planning standards for the development of a least-cost reliable supply portfolio over the forecast period. In accordance with the Settlement Agreement in DG 04-133/DG 04-175, the probability distribution of the effective degree days used in this analysis was determined using Monte Carlo techniques.

5. Determine Customer Requirements Under Design Weather Conditions

Using the applicable design day and design year weather planning standards, EnergyNorth determined the design year sendout requirements and the design day (peak day) sendout requirements. These design sendout requirements established the Company's resource requirements over the forecast period.

Based on the foregoing process, EnergyNorth projects incremental throughput of 1,444,800 MMBtu over the forecast period assuming normal weather (see Chart III-A-1). Overall, this growth in firm sales represents a 10.5 percent total increase in sendout requirements over the forecast period, or 2.6 percent per year on average. The development of EnergyNorth's five-year forecast of customer sendout requirements, based on the steps set forth above is described in the following sections

B. Forecast of Incremental Sendout

1. Introduction

The first step in EnergyNorth's forecast process is to prepare a five-year forecast of annual incremental sendout. Annual incremental sendout is the net increase in load that the Company expects to experience over the forecast period. This annual projection of incremental sendout is then added to the reference or "springboard" year sendout, which is derived from EnergyNorth's regression analysis of the latest split-year daily sendout and weather data, as described in Section III.C., to determine total firm sendout requirements.

The process used to forecast incremental sendout over the forecast period consists of five components. First, EnergyNorth develops a demand forecast of loads associated with traditional residential and commercial/industrial markets. To accomplish this, EnergyNorth developed econometric models, which are discussed in Section III.B.2(a). Throughput in the residential sector is discussed in Sections III.B.2 (b)(i-iii), below, and the commercial/industrial sector is discussed in Sections III.B.2. (b)(iv-vi), below.

Second, EnergyNorth develops a forecast for non-traditional markets that includes NGVs and large-scale power generation. While non-traditional markets are part of EnergyNorth's forecasting process, the Company is forecasting no demand in the NGV and large-scale cogeneration markets (Sections III.B.3.(a) and III.B.3.(b), respectively) based on the current and anticipated lack of activity in those markets. EnergyNorth's natural gas demand forecast for traditional customers, together with its forecasts of non-traditional market demands, results in a total forecast of incremental customer demand over the 2006/07 through 2010/11 forecast period.

Third, EnergyNorth accounts for the load reductions forecasted to result from the implementation of DSM, also known as gas energy efficiency programs, because these reductions are exogenous to the demand forecast generated by the econometric model. These load reductions are based on the estimated reductions prepared in conjunction with EnergyNorth's approved market transformation program (discussed in Section III.B.4, below).

Fourth, EnergyNorth monitors migration of sales customers to transportation service to determine if adjustments to its forecast are warranted (discussed in Section III.B.5, below).

Finally, EnergyNorth develops two alternatives to the base case demand forecast, that represent high and low sendout cases (discussed in Section III.B.6, below). The development of these alternative forecasts enables the Company to evaluate its ability to meet customer requirements with portfolio resources under a range of weather and economic conditions.

2. Demand Forecast for Traditional Markets

As mentioned above, the first step of the forecasting process is to prepare a five-year forecast of annual incremental sendout. To prepare this forecast, the Company first develops a demand forecast of loads associated with traditional residential and commercial/industrial markets using econometric models.[2] The Company began by reviewing the models specified in its 1998 Integrated Resource Plan filed with the Commission on November 30, 1998 in DR-98-134, and then updated those models by re-estimating the parameters of the models using updated historical data.

(a) The Econometric Models

The statistical models used by the Company relate sales by class to factors such as population, labor force, gas price and gross state product. Annual sales data were expanded to cover the twenty-two year period of January 1984 through December

[2] The Company agreed as part of the Settlement to develop econometric models for this forecast to replace the end-use model used in its most recent IRP.

2005. This information was used in conjunction with forecasts of economic factors provided by Global Insight, Inc. to develop the sales forecast.

The Company used the SAS statistical software package to perform the statistical data analysis that determined the relationships between the dependent variables and the explanatory variables in each of the equations used in the econometric models.

(b) The Forecast

The Company segmented its sales forecast by sector producing one forecast for residential sales and another for commercial and industrial sales.

For the residential sector, the Company tested two modeling structures. The first structure begins with forecasts of both number of residential customers and the use per residential customer. The number of customers is based on growth rates of generally available variables such as population, employment, while use per customer captures price effects, appliance saturation, and efficiency improvements. Multiplying the results of these two forecasts creates the forecast of residential sales. This structure assumes that it is easier to forecast each component separately. The second structure produces a forecast of residential sales directly, by relating total residential sales to independent variable such as gross state product and gas price. However, if one forecasts sales directly, it is possible that the effects of variables such as degree days, population and employment will overwhelm the effect of variables such as price. Because it is not clear which structure will produce the best forecast, the Company combined the results of the two models to minimize the errors that might be inherent in either one of them

For the residential sector, the Company developed a broad range of explanatory variables from sources such as the US Bureau of the Census, the US Bureau of Labor Statistics, the US Bureau of Economic Analysis, the Energy Information Administration of the US Department of Energy and the Company's own database. In nearly all cases, the Company collected statewide New Hampshire data because data specific to EnergyNorth's service territory were limited or non-existent. These variables were:

- State population
- State personal income
- State per capita income
- State wage and salary disbursement
- Statewide employment
- Statewide housing units and statewide households
- Statewide residential fuel oil sales and unit cost
- Statewide residential natural gas sales and unit cost
- Manchester, NH normal and actual degree days
- EnergyNorth therm sales and average rates to residential customers
- New Hampshire City Gate gas price

Table III-I gives additional details on these variables. Similar variables were identified for the commercial and industrial (C&I) sector:

- All of the above variables except those relating specifically to the residential sector
- EnergyNorth average rates for commercial and industrial customers
- EnergyNorth therm sales and customer totals for commercial and industrial customers
- Other EIA energy consumption and unit cost data for commercial and industrial sector

Table III-1

Variables Analyzed in Forecasting Practices

Index	Variable Name	Unit	Description	Source	Period Covered
1	CUSN	Customers	ENGI Number of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
2	CUSH	Customers	ENGI Number of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
3	CUSR	Customers	ENGI Number of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
4	CUSI	Customers	ENGI Number of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
5	CUSC	Customers	ENGI Number of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
6	CUSCI	Customers	ENGI Number of Commercial and Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
7	USEN	DTH/Customer	ENGI Gas Consumption per Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
8	USEH	DTH/Customer	ENGI Gas Consumption per Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
9	USER	DTH/Customer	ENGI Gas Consumption per Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
10	USEC	DTH/Customer	ENGI Gas Consumption per Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
11	USEI	DTH/Customer	ENGI Gas Consumption per Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
12	USECI	DTH/Customer	ENGI Gas Consumption per C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
13	USNN	DTH/Customer	ENGI Gas Consumption per Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
14	USNH	DTH/Customer	ENGI Gas Consumption per Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
15	USNR	DTH/Customer	ENGI Gas Consumption per Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
16	USNC	DTH/Customer	ENGI Gas Consumption per Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
17	USNI	DTH/Customer	ENGI Gas Consumption per Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
18	USNCI	DTH/Customer	ENGI Gas Consumption per C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
19	GASN	DTH	ENGI Gas Consumption of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
20	GASH	DTH	ENGI Gas Consumption of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4

21	GASR	DTH	ENGI Gas Consumption of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
22	GASC	DTH	ENGI Gas Consumption of C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
23	GASI	DTH	ENGI Gas Consumption of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
24	GASCI	DTH	ENGI Gas Consumption of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
25	GSNN	DTH	ENGI Normal Gas Consumption of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
26	GSNH	DTH	ENGI Normal Gas Consumption of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
27	GSNR	DTH	ENGI Normal Gas Cons. of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
28	GSNC	DTH	ENGI Normal Gas Consumption of C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
29	GSNI	DTH	ENGI Normal Gas Consumption of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
30	GSNCI	DTH	ENGI Normal Gas Consumption of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
31	CPI	1982-84 = 100	Consumer Price Index	Global Insight	1984Q1-2020Q4
32	GSP	Millions of $	NH Gross State Product—Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
33	RGSP	Millions of 2000 $	NH Real Gross State Product—Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
34	POP	Thousands	NH Total Population	Bureau of Census, Current Population Reports	1984Q1-2020Q4
35	NMIG	Thousands	NH Net Migration	Bureau of Census, Current Population Reports	1984Q1-2020Q4
36	EMP	Thousands	NH Employment, Total Non-Agriculture	Bureau of Labor Statistics	1984Q1-2020Q4
37	RUEM	Percent	NH Unemployment Rate	Bureau of Labor Statistics	1984Q1-2020Q4
38	UEMP	Thousands	NH Number Unemployed	Bureau of Labor Statistics	1984Q1-2020Q4
39	REMP	Thousands	NH Resident Employment	Bureau of Labor Statistics	1984Q1-2020Q4
40	LBFC	Thousands	NH Total Labor Force	Bureau of Labor Statistics	1984Q1-2020Q4
41	HH	Thousands	NH Households, Family and Non-Family	Global Insight	1984Q1-2020Q4
42	HSTM	Thousands	NH Housing Starts, Private Multi-Family	Global Insight	1984Q1-2020Q4
43	HSTS	Thousands	NH Housing Starts, Private	Global Insight	1984Q1-

			Single Family		2020Q4
44	HSTT	Thousands	NH Housing Starts, Total Private	Global Insight	1984Q1-2020Q4
45	HSOLD	Thousands	NH Home Sales, Existing Single-family units	Global Insight	1984Q1-2020Q4
46	HINC	Thousands of $	NH Average Household Income	Global Insight	1984Q1-2020Q4
47	PCI	Thousands of $	NH Per Capita Personal Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
48	RPCI	Thousands 2000 $	NH Real Per Capita Personal Income	Bureau of Economic Analysis	1984Q1-2020Q4
49	PINC	Millions of $	NH Personal Income, Total, By Place of Residence	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
50	RPINC	Millions of 2000 $	NH Real Personal Income, Total	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
51	RPIR	Millions of 2000 $	NH Real Income, Residence Adjustment	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
52	RPTR	Millions of 2000 $	NH Real Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4
53	PITP	Millions of $	NH Personal Income, Total Proprietors Income,	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
54	TPTR	Millions of 2000 $	NH Real Total Proprietors Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
55	PINF	Millions of $	NH Personal Income, Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4
56	INDX	(2002=100)	NH Industrial Production Index, Total	Global Insight	1984Q1-2020Q4
57	PRCO	($/MCF)	New Hampshire #2 Heating Oil Production Price For residential Heating	U.S. Energy Information Administration	1984Q1-2005Q4
58	PRCG	($/MCF)	New Hampshire Natural Gas City Gate Price	U.S. Energy Information Administration	1984Q1-2005Q4
59	PRCR	($/MCF)	New Hampshire Residential Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
60	PRCC	($/MCF)	New Hampshire Commercial Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
61	PRCI	($/MCF)	New Hampshire Industrial Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
62	PRCCI	($/MCF)	New Hampshire C&I Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
63	EGYO	(MMCF)	New Hampshire #2 Heating Oil consumption For residential Heating	U.S. Energy Information Administration	1984Q1-2005Q4
64	EGYG	(MMCF)	New Hampshire Natural Gas consumption by All Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
65	EGYR	(MMCF)	New Hampshire Residential Natural Gas consumption Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
66	EGYC	(MMCF)	New Hampshire Commercial	U.S. Energy	1984Q1-

			Natural Gas consumption Updated on 9/14/2005	Information Administration	2005Q4
67	EGYI	(MMCF)	New Hampshire Industrial Natural Gas consumption Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
68	RPRR	PRCR/PRCO	Price Ratio: Res. Natural Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
69	RPRC	PRCC/PRCO	Price Ratio: Commercial Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
70	RPRI	PRCI/PRCO	Price Ratio: Industrial Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
71	REGR	EGYR/EGYO	Energy Use Ratio: Res. Natural Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
72	REGC	EGYC/EGYO	Energy Use Ratio: Commercial Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
73	REGI	EGYI/EGYO	Energy Use Ratio: Industrial Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
74	REVN	($)	ENGI Revenue to Residential Non-Heating Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
75	REVH	($)	ENGI Revenue to Residential Heating Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
76	REVR	($)	ENGI Revenue to Residential Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
77	REVC	($)	ENGI Revenue to Commercial Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
78	REVI	($)	ENGI Revenue to Industrial Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
79	REVCI	($)	ENGI Revenue to Commercial and Industrial Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
80	RVNN	($)	ENGI Revenue (Normal) to Residential Non-Heating Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
81	RVNH	($)	ENGI Revenue (Normal) to Residential Heating Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
82	RVNR	($)	ENGI Revenue (Normal) to Residential Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
83	RVNC	($)	ENGI Revenue (Normal) to Commercial Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
84	RVNI	($)	ENGI Revenue (Normal) to	EnergyNorth Billing	1984Q1-

			Industrial Customer ($)	Frequency Record	2005Q4
85	RVNCI	($)	ENGI Revenue (Normal) to C&I Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
86	CHGN	($/MMBTU)	ENGI Company Charge to Residential Non-Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
87	CHGH	($/MMBTU)	ENGI Company Charge to Residential Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
88	CHGR	($/MMBTU)	ENGI Company Charge to Residential Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
89	CHGC	($/MMBTU)	ENGI Company Charge to Commercial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
90	CHGI	($/MMBTU)	ENGI Company Charge to Industrial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
91	CHGCI	($/MMBTU)	ENGI Company Charge to C&I Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
92	CHNN	($/MMBTU)	ENGI Company charge (Normal) to Res. Non-Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
93	CHNH	($/MMBTU)	ENGI Company charge (Normal) to Res. Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
94	CHNR	($/MMBTU)	ENGI Company charge (Normal) to Residential Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
95	CHNC	($/MMBTU)	ENGI Company charge (Normal) to Commercial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
96	CHNI	($/MMBTU)	ENGI Company charge (Normal) to Industrial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
97	CHNCI	($/MMBTU)	ENGI Company charge (Normal) to C&I Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
98	CDDN		Normal Calendar Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
99	CDDA		Actual Calendar Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
100	BDDN		Normal Billing Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
101	BDDA		Actual Billing Degree Days	EnergyNorth Billing	1984Q1-

As was done in the 1998 forecast, the Company developed models based on quarterly data. This approach accounts for the seasonality of both customer and sales data. For some variables, such as population and employment, data were only available annually. In these instances, the Company assumed that the data were for quarter four, and interpolated for quarters one, two and three. Although, SAS offers a variety of forecasting models including dynamic regression, Box-Jenkins, exponential smoothing, and moving averages, the Company focused on dynamic regression (i.e. econometrics) because it is the most commonly used method in the utility industry and allows the user to develop relationships between independent or explanatory variables and energy sales.

In addition to the explanatory variables, SAS allows the user to incorporate both lagged variables and autocorrelation functions into the models. When developing a forecasting model, there will always be "error" when comparing the "fit" of the model to the actual data. One would expect, however, that these errors (or residuals) would be relatively small and random in nature. If the errors are not random (e.g., every fourth quarter the forecast is too high and every second quarter it is too low), then a pattern exists and the error terms are not random. In these instances better models should be designed. Both lagged variables and autocorrelation functions are intended to eliminate the non-random components of the errors.

Because SAS allows the user to develop a large number of models, it is important to develop criteria regarding what constitutes a "good" model. In general the Company applied the following criteria:

- The t-tests for all explanatory variables are significant (i.e. exceed 1.0)[3]
- The relationship between the dependent and explanatory variable is logical and of the correct sign (e.g., higher gas prices should produce lower sales)
- The resulting forecast is reasonable (e.g., a forecast that shows sales decreasing to zero by year 2010 would be eliminated regardless of the power of the other statistics).
- That significant autocorrelation between the residuals (errors) has been eliminated (i.e. Durbin-Watson statistic is insignificant)
- The addition of new variables does not improve model performance
- Reliable forecasts of the independent variables are available.

i. Residential Customer Forecast

The Company found that there is significant seasonality to the residential customer data with a higher customer base in the winter than in the summer. Therefore, each of the econometric models developed for residential customers contained a term for residential customers lagged one period and an autocorrelation function of period four. These were by far the most significant variables for all models tested.

Following these adjustments, the most significant variables in order were population (Pop), employment (EMP) and gross state product (GSP). The four models specified passed the criteria mentioned above. One contains gross state product as the primary explanatory variable, the second employment, the third population, and the fourth contains both gross state product and population. In addition, the Company chose the Box-Jenkins ARIMA method in SAS as the time-series model and estimated an equation consistent with this approach. An additional time series model, Winter's Exponential

[3] The Company attempted to maintain t-tests at the 2.0 significance level, but in some cases found it necessary to retain some variables that tested between 1.0 and 2.0 to maintain the theoretical form of the equations.

Smoothing, was chosen as a final model for each forecast segment. The details of these models is contained in Appendix A.

After completing the estimation of the parameters for each equation in the above models, the Company then applied a forecast of the explanatory variables to the model to produce the forecast of residential customers. The forecasts of the explanatory variables were provided by Global Insight, Inc., with which the Company has a contract to provide forecasts of energy, economic, and demographic variables for its service territory.

Three sources were used for forecasted data:

- The US Bureau of Economic Analysis — this source provided forecasts for population, gross state product, employment and wages for 1998, 2000, 2005 and 2010 at the state level.
- The Energy Information Agency — this source provided NH pricing data for natural gas city gate plus average MMBtu unit pricing and consumption data by end user classification for electricity, #2 fuel oil; #6 residual oil, LPG and natural gas, forecast annually for 2006 through 2030.
- SAS was used to produce its own forecasts of independent variables where no other forecast existed.

Using the model specifications described above, six residential customer forecasts were produced:

1. Forecast A1 used a model specification containing NH gross state product (GSP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1) as the independent variables. The GSP forecast was from the US Bureau of Economic Analysis. This forecast predicts a growth rate of 3.0 percent from year 2005/06 to year 2010/2011 and a total number of residential customers in 2010/11 of 84,172.

2. Forecast A2 used a model specification containing NH employment (EMP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1) as the independent variables. The EMP forecast was from the US Bureau of Economic Analysis. This forecast predicts a growth rate of **0.8** percent with a total number of residential customers in year 2010/11 of 74,772.
3. Forecast A3 used a model specification containing population (POP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1). The population forecast was from the US Bureau of Economic Analysis, This forecast predicts a 2005/06 to 2010/11 growth rate of 0.7 percent with the total number of residential customers in 2010/11 of 74,660.
4. Forecast A4 is the same as A3 except that NH gross state product (GSP) was added. This forecast predicts a growth rate of 2.5 percent with a total number of residential customers in 2010/11 of 81,918.
5. Forecast A5 uses the SAS Box-Jenkins ARIMA model. This forecast predicts a growth rate of 2.1 percent with the expected number of residential customers in 2010/11 being 80,612.
6. Forecast A6 uses a multiplicative Winter's exponential smoothing model with linear trend and multiplicative seasonality. It forecasts a growth rate of 2.1 percent and a total of 79,981 residential customers by 2010/11.

These forecasts were then combined to produce the aggregate residential customer forecast for EnergyNorth (see Table III-2). Each econometric model specification received a weight of 0.15 and each time series model received a weight of 0.20. Forecasts AI through A4 were averaged and given a combined weighting of 0.60. The time series forecasts A5 and A6 were also averaged and received a combined weighting of 0.40.

Table III-2

EnergyNorth Forecast Results

Residential Customer Forecast

Model	A1	A2	A3	A4	ARIMA	Winter's	Weighted Residential Customers
Dependent	CUSR	CUSR	CUSR	CUSR	CUSR	CUSR	
Independent	Intercept CUSR_1 GSP AUTO(-4)	CUSR_1 EMP AUTO(-4)	CUSR_1 POP AUTO(-4)	CUSR_1 GSP POP AUTO(-4)			
Weight	15.00%	15.00%	15.00%	15.00%	20.00%	20.00%	100.00%
Residential Customer Forecast -- Percent Growth from Base Year (2005)							
2006Q4-2007Q3	2.90%	0.78%	0.83%	2.49%	2.79%	2.40%	2.09%
2007Q4-2008Q3	3.03%	0.80%	0.79%	2.52%	2.21%	2.02%	1.93%
2008Q4-2009Q3	3.15%	0.77%	0.71%	2.59%	1.56%	1.98%	1.81%
2009Q4-2010Q3	3.06%	0.74%	0.66%	2.47%	1.83%	1.94%	1.82%
2010Q4-2011Q3	2.94%	0.77%	0.68%	2.35%	1.95%	1.91%	1.81%
Average	3.02%	0.77%	0.73%	2.48%	2.07%	2.05%	1.89%
Residential Customer Forecast (Annual)							
2005Q4-2006Q3	72,552	71,950	71,981	72,470	72,768	72,263	72,349
2006Q4-2007Q3	74,659	72,510	72,575	74,273	74,799	73,995	73,861
2007Q4-2008Q3	76,917	73,089	73,150	76,145	76,449	75,492	75,283
2008Q4-2009Q3	79,342	73,653	73,672	78,114	77,644	76,988	76,644
2009Q4-2010Q3	81,772	74,197	74,155	80,039	79,067	78,485	78,035
2010Q4-2011Q3	84,172	74,772	74,660	81,918	80,612	79,981	79,447
Average	78,236	73,362	73,366	77,160	76,890	76,201	75,937

The result shown in Table III-2 is a forecasted growth rate in residential customers from 2005/06 - 2010/11 of 1.9 percent with a total of 79,447 residential customers expected in 2010/11. See the complete residential customer forecast results Appendix A.

ii. Residential Use Per Customer Forecast

For the residential use per customer forecast, there was a strong relationship between normalized use per customer and normal degree days. Therefore, each of the models developed for use per customer used normal degree days as an independent variable. The Company also applied an autocorrelation term of period four. Following these adjustments, the econometric models included variables for NH GSP and natural gas city gate price NH and then again with per capita income replacing NH GSP.

Using the model specifications described above, four residential use per customer forecasts were produced:

1. Forecast B1 used a model specification containing NH gross state product (GSP), natural gas city gate price lagged one quarter (PRCG_1), normal degree days (CDDN), and an autoregressive term of period four (AUTO(-4)). Again, the GSP forecast was from the US Bureau of Economic Analysis, natural gas city gate price was from the Energy Information Administration, and normal degree days are a thirty year average based on National Weather Service data for Manchester, NH. This forecast predicts a growth rate of 1.2 percent from year 2005/06 to year 2010/11 and a total annual residential use per customer in 2010/11 of 91 MMBtu.
2. Forecast B2 used a model specification containing NH per capita income (PCI), natural gas city gate price lagged one quarter (PRCG_1), normal degree days (CDDN), and an autoregressive term of period four (AUTO(-4)). The NH per capita income forecast was calculated using population and personal income data from the US Bureau of Economic Analysis, natural gas city gate price and normal degree day data was the same as described in description of the B1 forecast. This forecast predicts a growth rate of 0.95 percent from year 2005/06 to year 2010/11 and a total annual residential use per customer in 2010/11 of 89 MMBtu.

3. Forecast B3 uses the Box-Jenkins ARIMA model. This forecast predicts a growth rate of -0.2 percent with the total annual residential use per customer declining from 88 MMBtu per year in 2005/06 to 86 MMBtu in 2010/11.

4. Forecast B4 uses a multiplicative Winter's exponential smoothing model with linear trend and multiplicative seasonality. It also forecasts a declining growth rate of -0.1 percent and a total residential use per customer holding virtually steady at 85 MMBtu per year from 2005/06 to 2010/11.

These forecasts were then combined to produce the aggregate residential use per customer forecast for EnergyNorth (see Table III-3). Both of the econometric models received a weight of 0.20 and each time series model received a weight of 0.30. Forecasts B 1 and B2 were averaged and given a combined weighting of 0.40. The time series forecasts, B3 and B4, are also averaged and received a combined weighting of 0.60.

See the complete residential use per customer forecast results in Appendix A.

Table III-3

EnergyNorth Forecast Results

Residential Gas Use Per Customer Forecast

Model	B1	B2	ARIMA	Winter's	Weighted Residential Use Per
Dependent	USNR	USNR	USNR	USNR	
Independent	PRCG_1	PRCG_1			
	GSP	PCI			
	CDDN	CDDN			
	AUTO(-4)	AUTO(-4)			
Weight	20.00%	20.00%	30.00%	30.00%	100.00%
Residential Use Per Customer Forecast -- Percent Growth from Base Year (2005)					
2006Q4-2007Q3	1.21%	0.97%	-2.13%	2.81%	0.77%
2007Q4-2008Q3	1.24%	1.00%	3.34%	-0.84%	1.17%
2008Q4-2009Q3	1.34%	1.03%	-0.76%	-0.84%	0.39%
2009Q4-2010Q3	1.22%	0.94%	-1.09%	-0.85%	0.26%
2010Q4-2011Q3	1.14%	0.81%	-0.59%	-0.86%	0.31%
Average	1.23%	0.95%	-0.24%	-0.11%	0.58%
Residential Use Per Customer Forecast (Annual)					
2005Q4-2006Q3	85	85	88	85	86
2006Q4-2007Q3	86	86	86	88	86
2007Q4-2008Q3	87	86	89	87	87
2008Q4-2009Q3	88	87	88	86	88
2009Q4-2010Q3	90	88	87	86	88
2010Q4-2011Q3	91	89	86	85	88
Average	88	87	87	86	87

iii. Residential Sales Forecast

As mentioned previously, residential sales forecasts were developed by (1) combining the residential customer and use per customer forecasts and (2) by independently forecasting residential sales. All data on residential sales were normalized by EnergyNorth to account for deviations in weather.

Two econometric models were developed for residential sales using quarterly data. In each case an autoregressive term of period four was used. The first model also included a term for NH gross state product (GSP). This forecast, C1, produced a 2005/06-2010/11 growth rate of 2.8 percent with total residential sales of 7.38 million MMBtu in 2010/11. The second model, C2, was the similar to C1, but also included the term natural gas city gate price. The resulting forecast C2 showed a growth rate of 3.0 percent and total residential sales in 2010/11 of 7.37 million therms.

A time series forecast, C3, uses the ARIMA model. This forecast predicts a growth rate of 1.6 percent, with total annual residential sales of 6.90 million MMBtu in 2010/11 These forecasts were then combined to produce the weighted residential therm sales forecast for EnergyNorth (see Table III-4 and Figure III-1). Both of the econometric models received a weight of 0.30 resulting in forecasts C1 and C2. These were then averaged and given a combined weighting of 0.60. The time series model C3 received a weight of 0.40. The weighted residential sales forecast shows a growth rate of 2.5 percent and sales of 7.19 million MMBtu in the year 2010/11.

Next, the Company produced a forecast of residential sales using the aggregate of the residential customer models (A1 through A6) multiplied times the aggregate of the residential use per customer models (B 1 through B4). The product of these two aggregated forecasts yielded a calculated residential sales forecast reflecting an overall growth rate of 2.4 percent and MMBtu sales forecast of 6.98 million in the year 2010/11. Combining the calculated residential sales forecast with the weighted (C1 through C3) sales forecast on an equal (50%/50%) basis, produced a final residential sales forecast of 7.08 million therms in 2010/11 for an annualized growth rate of 2.5 percent from 2005/06-2010/11.

Table III-4

EnergyNorth Forecast Results

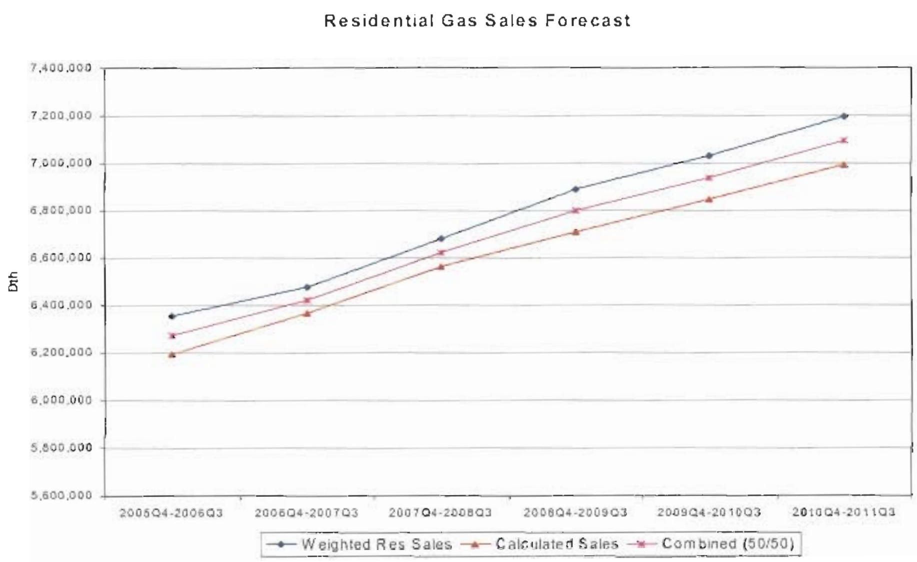
Residential Gas Sales Forecast

Model	C1	C2	ARIMA	Weighted Residential Sales	Calculated Sales	Combined (50/50)
Dependent	GSNR	GSNR	GSNR			
Independent	GSP Auto(-4)	PRCG GSP Auto(-4)				
Weight	30.00%	30.00%	40.00%	100.00%		
Residential Gas Sales Forecast -- Percent Growth from Base Year (2005)						
2006Q4-2007Q3	2.57%	2.86%	0.80%	1.96%	2.80%	2.37%
2007Q4-2008Q3	2.65%	2.91%	3.65%	3.12%	3.08%	3.10%
2008Q4-2009Q3	3.02%	3.23%	3.07%	3.10%	2.21%	2.66%
2009Q4-2010Q3	2.86%	3.00%	0.69%	2.05%	2.04%	2.05%
2010Q4-2011Q3	2.79%	2.88%	1.56%	2.34%	2.14%	2.24%
Average	2.78%	2.98%	1.95%	2.51%	2.45%	2.48%
Residential Gas Sales Forecast (Dth) (Annual)						
2005Q4-2006Q3	6,440,173	6,373,218	6,267,804	6,351,139	6,190,483	6,270,811
2006Q4-2007Q3	6,605,996	6,555,369	6,318,014	6,475,615	6,363,654	6,419,635
2007Q4-2008Q3	6,780,906	6,745,872	6,548,691	6,677,510	6,559,457	6,618,483
2008Q4-2009Q3	6,985,470	6,963,457	6,749,937	6,884,653	6,704,409	6,794,531
2009Q4-2010Q3	7,185,317	7,172,667	6,796,495	7,025,993	6,841,297	6,933,645
2010Q4-2011Q3	7,385,507	7,379,427	6,902,273	7,190,389	6,987,414	7,088,902
Average	6,897,228	6,865,002	6,597,202	6,767,550	6,607,786	6,687,668

See the complete residential load forecast results in Appendix A.

Figure III-1

Residential Natural Gas Sales Forecast



iv. C&I Customer Forecast

Similar to the residential customer models, the C&I customer models show seasonality as well as a strong relationship to population, employment and NH gross state product. Three econometric models were developed for C&I customers. All three models included autoregressive terms of period four (AUTO(-4)) and a lagged term of period one (CUSCI_1). Forecast D1, which includes the U.S. Bureau of Economic Analysis population data (POP), results in 11,448 commercial and industrial customers in 2010/11, equivalent to an annualized growth rate of 1.8 percent.

The second model substitutes labor force (LBFC) for population. This forecast, D2, predicts a growth rate of 1.7 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 11,413 by 2010/11.

The third model substitutes NH gross state product (GSP) for employment. This forecast, D3, predicts a growth rate of 6.3 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 14,425 by 2010/11.

The Box-Jenkins ARIMA Model is the fourth C&I customer forecast, and is designated D4. This forecast, D4, predicts a growth rate of 2.5 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 11,942 by 2010/11.

A Winter's Exponential Smoothing Model was used as the fifth model of C&I customers. This produced a 2010/11 forecast of C&I customers of 11,843 with a growth rate of 2.6 percent through the year 2010/11.

Forecasts Dl, D2 and D3, the econometric models, are based on population, employment and state GSP projections. Forecasts D4 (Box-Jenkins) and DS (Winters Exponential Smoothing) are time series projections. All five forecasts were given weights of 20 percent each and then were averaged, with the result giving the econometric models a weight of 60 percent and the time series models a weight of 40 percent. The combination of these forecasts produces a final prediction of commercial and industrial customers for EnergyNorth for 2010/11 of 12,214 or 3.0 percent growth per year from 2005/06-2010/11.

The annual forecast results for commercial and industrial customers can be seen in Table III-5. Complete details of the C&I customer forecast results can be found in Appendix A.

Table III-5

EnergyNorth Forecast Results

Commercial and Industrial Customer Forecast

Model	D1	D2	D3	ARIMA	Winter's	Weighted C&I Customers
Dependent	CUSCI	CUSCI	CUSCI	CUSCI	CUSCI	
Independent	CUSCI_1	CUSCI_1	CUSCI_1			
	POP	LBFC	GSP			
	AUTO(-4)	AUTO(-4)	AUTO(-4)			
Weight	20.00%	20.00%	20.00%	20.00%	20.00%	100.00%
Commercial & Industrial Customer Forecast -- Percent Growth from Base Year (2005)						
2006Q4-2007Q3	2.04%	1.95%	5.87%	2.55%	2.69%	3.03%
2007Q4-2008Q3	1.77%	1.70%	6.33%	2.63%	2.61%	3.04%
2008Q4-2009Q3	1.88%	1.83%	6.54%	2.53%	2.55%	3.13%
2009Q4-2010Q3	1.69%	1.67%	6.44%	2.43%	2.48%	3.04%
2010Q4-2011Q3	1.47%	1.43%	6.19%	2.42%	2.42%	2.91%
Average	1.77%	1.72%	6.27%	2.51%	2.55%	3.03%
Commercial & Industrial Customer Forecast (Annual)						
2005Q4-2006Q3	10,486	10,482	10,643	10,549	10,442	10,520
2006Q4-2007Q3	10,700	10,687	11,267	10,818	10,723	10,839
2007Q4-2008Q3	10,890	10,869	11,980	11,102	11,003	11,169
2008Q4-2009Q3	11,094	11,068	12,764	11,382	11,283	11,518
2009Q4-2010Q3	11,281	11,253	13,585	11,659	11,563	11,868
2010Q4-2011Q3	11,448	11,413	14,425	11,942	11,843	12,214
Average	10,983	10,962	12,444	11,242	11,143	11,355

v. C&I Use Per Customer

For C&I use per customer, the Company developed three econometric models and one time series model. All three econometric models included autoregressive terms of period four, the Energy Information Agency's natural gas city gate price projections for NH and normal degree days for Manchester, NH. Forecast E1, which also includes U.S. Bureau of Economic Analysis NH GSP data, results in 805 annual commercial and industrial

MMBtu use per customer in 2010/11, equivalent to an annualized growth rate of 1.9 percent.

Forecast E2, substitutes U.S. Bureau of Economic Analysis employment data in place of NH GSP. This forecast, E2, shows a decline from 2005/06 to 2010/11 to 702 annual commercial and industrial MMBtu use per customer in 2010/11, equivalent to an average rate of -0.6 percent.

Forecast E3 substitutes per capita income data in place of employment. This forecast, E3, show an average growth rate of 1.4 percent with 779 annual commercial and industrial MMBtu use per customer in 2010/11.

The Box-Jenkins ARIMA model for the time series forecast, model, E4 produced a forecast of C&I use per customer of 747 MMBtu in 2010/11, reflecting a slight decrease in C&I use per customer growth, -0.5 percent through 2010/11.

All four forecasts were combined and averaged using a weighting of 75 percent econometric and 25 percent time series. . The results produced a forecast of 758 C&I MMBtu per customer in 2010/11 that is equivalent to a 0.6 percent annualized growth rate from 2005/06 through 2010/11.

See Table III-6 for the C&I use per customer forecast results and appendix A for complete forecast results.

Table III-6

EnergyNorth Forecast Results

Commercial and Industrial Gas Use Per Customer Forecast

Model	E1	E2	E3	ARIMA	Weighted C & I Use Per
Dependent	USNCI	USNCI	USNCI	USNCI	
Independent	PRCG	PRCG	PRCG		
	GSP	EMP	PCI		
	CDDN	CDDN	CDDN		
	AUTO(-4)	AUTO(-4)	AUTO(-4)		
Weight	25.00%	25.00%	25.00%	25.00%	100.00%
Commercial & Industrial Use Per Customer Forecast -- Percent Growth from Base Year (2005)					
2006Q4-2007Q3	1.45%	-0.86%	0.98%	0.93%	0.63%
2007Q4-2008Q3	1.77%	-0.63%	1.28%	-1.74%	0.15%
2008Q4-2009Q3	2.19%	-0.53%	1.56%	-1.71%	0.38%
2009Q4-2010Q3	2.09%	-0.50%	1.54%	-0.30%	0.74%
2010Q4-2011Q3	2.05%	-0.49%	1.37%	0.43%	0.88%
Average	1.91%	-0.60%	1.35%	-0.48%	0.56%
Commercial & Industrial Use Per Customer Forecast (Annual)					
2005Q4-2006Q3	733	724	728	765	738
2006Q4-2007Q3	743	718	735	773	742
2007Q4-2008Q3	756	713	745	759	743
2008Q4-2009Q3	773	709	756	746	746
2009Q4-2010Q3	789	706	768	744	752
2010Q4-2011Q3	805	702	779	747	758
Average	767	712	752	756	747

vi. C&I Sales Forecast

As with the residential models, the Company forecast C&I sales in MMBtu normalized for weather. Models were developed by combining the C&I customer and use per customer data, as well as directly using econometric and time series methods. Using quarterly data, the Company developed an econometric model with autoregressive terms of period four (AUTO(-4)) along with natural gas city gate price data (PRCG) collected from the EIA. In the first econometric model, F1, a lagged term of period one (GSNCI_1) was also included. This model produced a forecast of 9.52 million

MMBtu for the C&I sector in 2010/11 equivalent to a 3.8 percent growth rate for the period 2005/06 through 2010/11.

The second econometric model, F2, replaces the lagged term of period one with an autoregressive term of period eight (AUTO(-8)). This model produced a forecast of 9.47 million MMBtu for the C&I sector in 2010/11 equivalent to a 1.9 percent growth rate for the period 2005/06 through 2010/11.

The third econometric model, F3, reinserts the lagged term of period one (GSNCI_1) and continues using natural gas city gate prices (PRCG) and the autoregressive terms of periods four (AUTO(-4)) and eight (AUTO(-8)). This model produced a forecast of 9.47 million MMBtu for the C&I sector in 2010/11 equivalent to a 3.7 percent growth rate for the period 2005/06 through 2010/11.

The Box-Jenkins ARIMA model, F4, produced a forecast of 9.27 million MMBtu for the C&I sector in 2010/11 or an annualized growth rate of 2.8 percent.

The final C&I therm load weighted forecast was an average of Forecast Fl through F3 (the econometric models) at 20 percent each, with Forecast F4 (the time series forecast) weighted at 40%. Then, the weighted C&I sales forecasts and the product of the number of customers times the use per customer forecast were combined equally (50/50). The result was a forecast of 9.32 million MMBtu in 2010/11, equivalent to a 3.8 percent growth rate from 2005/06 through 2010/11.

See Figure III-2 and Table III-7 for the C&I therm load forecast summary and Appendix A for complete details of the forecast.

Table III-7

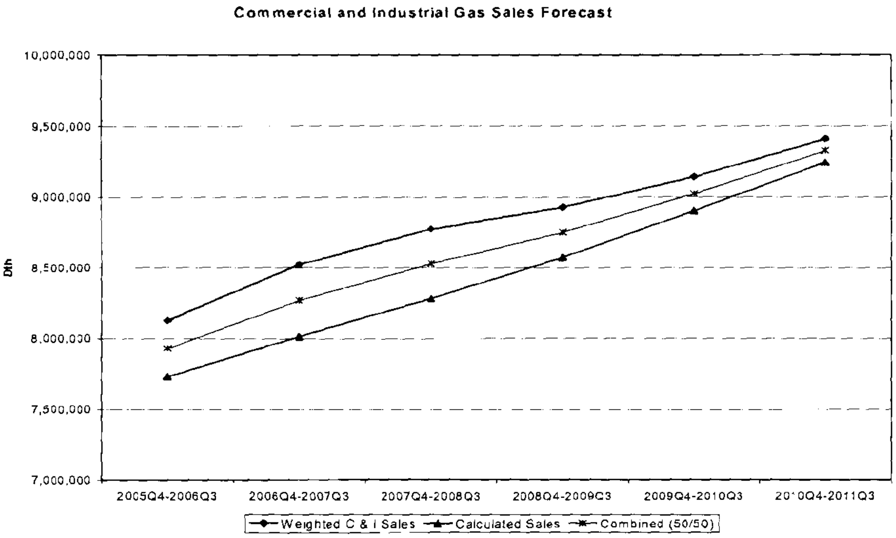
EnergyNorth Forecast Results

Commercial and Industrial Gas Sales Forecast

Model	F1	F2	F3	ARIMA	Weighted C & I Sales	Calculated Sales	Combined (50/50)
Dependent	GSNCI	GSNCI	GSNCI	USNCI			
Independent	GSNCI_1	PRCG	GSNCI_1				
	PRCG	AUTO(-4)	PRCG				
	AUTO(-4)	AUTO(-8)	AUTO(-4)				
			AUTO(-8)				
Weight	20.00%	20.00%	20.00%	40.00%	100.00%		
Commercial & Industrial Gas Sales Forecast (Percent Growth from Base Year (2005)							
2006Q4-2007Q3	5.34%	2.73%	5.55%	5.46%	4.87%	3.57%	6.85%
2007Q4-2008Q3	4.03%	1.56%	3.78%	2.75%	2.96%	3.34%	3.15%
2008Q4-2009Q3	3.53%	1.60%	3.33%	0.09%	1.72%	3.51%	2.59%
2009Q4-2010Q3	3.09%	1.71%	2.95%	2.20%	2.43%	3.85%	3.12%
2010Q4-2011Q3	2.75%	1.81%	2.64%	3.69%	2.90%	3.84%	3.36%
Average	3.75%	1.88%	3.65%	2.84%	2.98%	3.62%	3.81%
Commercial & Industrial Gas Sales Forecast (Dth) (Annual)							
2005Q4-2006Q3	7,924,343	8,628,982	7,919,898	8,067,522	8,121,654	7,734,162	7,734,162
2006Q4-2007Q3	8,347,166	8,864,129	8,359,073	8,508,086	8,517,308	8,010,453	8,263,881
2007Q4-2008Q3	8,683,945	9,002,617	8,675,271	8,742,207	8,769,249	8,278,350	8,523,800
2008Q4-2009Q3	8,990,327	9,146,297	8,964,552	8,749,767	8,920,142	8,569,259	8,744,701
2009Q4-2010Q3	9,268,498	9,302,969	9,228,745	8,942,571	9,137,071	8,898,799	9,017,935
2010Q4-2011Q3	9,523,502	9,471,707	9,472,064	9,272,510	9,402,459	9,240,153	9,321,306
Average	8,789,630	9,069,450	8,769,934	8,713,777	8,811,314	8,455,196	8,600,964

Figure III-2

Commercial & Industrial Firm Sales & Transportation Forecast



vii. Summary of Final Forecast

For the final forecast, the Company averages of forecasts developed using the several equations specified to produce a more accurate forecast than using a single equation. In this way, the forecast minimizes the forecast error associated with any single equation.

The range of forecasts produced by these models creates a distribution around the final forecast. This provides the Company with an assessment of uncertainty and allows it to plan for high growth and low growth conditions. These high growth and low growth scenarios are discussed in more detail in Section 6, Sensitivity Analysis.

Table III-8 summarizes the ENGI forecast by sector.

Table III-8

EnergyNorth Natural Gas, Inc. – Five Year Forecast

Five Year Forecast (2005 - 2010) (MMBtu)						
	Year	Residential	Commercial & Industrial	DSM	Total Demand	% Change
		(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	
	2005Q4-2006Q3	6,270,811	7,924,379	-77573	14,117,617	
1	2006Q4-2007Q3	6,419,635	8,263,881	-77573	14,605,942	3.46%
2	2007Q4-2008Q3	6,618,483	8,523,800	-77573	15,064,710	3.14%
3	2008Q4-2009Q3	6,794,531	8,744,701	-77573	15,461,659	2.63%
4	2009Q4-2010Q3	6,933,645	9,017,935	-77573	15,874,007	2.67%
5	2010Q4-2011Q3	7,088,902	9,321,306	-77573	16,332,634	2.89%
	Average	6,771,039	8,774,324	-77573	15,467,790	2.96%

(c) <u>Forecast of Incremental Demand for Traditional Markets</u>

EnergyNorth's incremental demand forecasts (base case) for traditional markets are presented in Chart III-B-1. The incremental demand forecast is calculated as the year-to-year change in demand that results from the econometric forecast models. The Company adds the annual incremental demand determined in this way to the reference year sendout described in Section III C. As set forth in Chart III-B-1, EnergyNorth projects total net throughput additions over the forecast period (2006/07 through 2010/11) of 1,416,400 MMBtu for traditional core markets. Overall, this growth in traditional-market firm sales represents a 10.0 percent increase in sendout requirements over the forecast period, or 2.5 percent per year on average (see Chart III-A-1).

The following sections describe the specific steps involved with the development of EnergyNorth's incremental demand forecast for traditional market segments, including residential, and commercial and industrial customers.

(i) Residential Market

Chart III-B-1 presents EnergyNorth's demand forecast for residential customers. This forecast shows 573,247 MMBtu of net incremental load additions over the forecast period. Chart III-B-1 shows that EnergyNorth is projected to add an average of 143,312 MMBtu net load annually, between 2006/07 and 2010/11. As shown on Chart III-A-1, this growth in residential sales represents an overall increase in residential sendout of 2.3 percent per year on average or 9.3 percent over the forecast period.

(ii) Commercial and Industrial Market

Chart III-B-1 presents EnergyNorth's updated commercial and industrial demand forecast. This forecast shows 843,153 MMBtu of net incremental load over the forecast period. Chart III-B-1 shows that EnergyNorth is projected to add an average of 210,788 MMBtus net load annually between 2006/07 and 2010/11. As shown on Chart III-A-1, this increase in commercial/industrial sales represents an overall increase in commercial/industrial sendout of 2.6 percent per year on average, or 10.6 percent over the forecast period.

3. Demand Forecast for Non-Traditional Markets

(a) Natural Gas Vehicles

As shown on Chart III-B-1, the Company's forecast indicates no demand in the natural gas vehicle market in the EnergyNorth service territory. The Company's forecast of demand in the NGV market is driven by governmental regulations requiring or encouraging NGV use among certain commercial and governmental vehicle fleets, and the Company's marketing efforts with those vehicle fleet operators. At the time that this forecast was prepared, the Company's marketing representatives did not anticipate any significant demand in this market.

(b) Large-Scale Cogeneration Market

EnergyNorth's assessment of the large-scale cogeneration market is that the natural gas required to meet the demands of the potential customers in this market during the forecast period will not have an impact on EnergyNorth's sendout requirements or resource plan. EnergyNorth is not currently aware of any large-scale gas-fired cogeneration facilities planned for locations within the EnergyNorth service territory over the forecast period that do not yet have their natural gas requirements in place. However, consistent with EnergyNorth's recent experience, if a new gas-fired cogeneration power plant were to be located in EnergyNorth's service territory, EnergyNorth believes that the gas requirements of such facilities would likely be served by third-party gas suppliers in conjunction with Supplier Service provided by EnergyNorth from the city gate to the facility. Accordingly, EnergyNorth's forecast shows no demand for the large-scale cogeneration market and no impact on the resource plan.

4. Demand-Side Management

EnergyNorth is in the first year of a three-year extension of its energy efficiency program approved by the Commission in Order No. 24,636 dated June 8, 2006 in Docket DG 06-032. Subject to Commission review and approval, EnergyNorth expects to continue its efficiency program beyond the April 30, 2009 expiration of the current plan through to the end of the forecast period. EnergyNorth estimates volume reductions of 77,573 MMBtus per year on average from DSM measures during the forecast period (see Chart III-B-1). To develop projections of future energy-savings impacts of the DSM programs, EnergyNorth utilized a spreadsheet developed within the NSTAR Energy Efficiency Collaborative (hereinafter referred to as the "Energy Efficiency Model").[4] The Energy Efficiency Model is used to track costs and benefits relating to energy efficiency and market transformation programs. Once data is input to the Energy Efficiency Model it calculates the present value of program benefits and costs and produces a cost/benefit ratio. In addition, the output of the model also includes a projection of future energy savings for each program analyzed. In addition, EnergyNorth updated the Energy Efficiency Model in 2004 to reflect current assumptions relating to program costs and benefits, program participation, the discount rate, and avoided natural gas costs. For the analyses conducted to estimate the future savings from EnergyNorth's DSM programs, funding for all programs was assumed to continue through the forecast period ending October 2011. Savings from program measures are reflected in the model over the entire useful life of measures.

[4] The NSTAR model was initially developed to analyze electric energy-efficiency programs in Massachusetts. Northeast Efficiency Energy Partnerships ("NEEP") built the first version of the model in 1997 to analyze the costs and benefits of its regional programs. In January 1998, ComElectric retained GDS Associates, Inc. ("GDS") to perform a cost/benefit analysis of its electric energy-efficiency programs. During the first quarter of 1998, GDS enhanced the NEEP model and calculated benefit/cost ratios for ComElectric's programs. In 2000, following the BECo/Commonwealth merger, NSTAR retained Optimal Energy to enhance the model to analyze natural gas energy-efficiency programs. KeySpan used the enhanced model in December 2000 and January 2001 to analyze the costs and benefits of five regional GasNetworks energy-efficiency programs. KeySpan now uses a new GDS model to calculate the benefits and costs of its energy efficiency programs. The GDS model was initially used for projects for Fitchburg Gas and Electric. Many GDS clients now use the GDS model, including KeySpan, Efficiency Maine, the Vermont Department of Public Service, the New Hampshire Electric Cooperative, Public Service of New Mexico and other GDS clients.

5. Sensitivity Analysis

(a) Overview

EnergyNorth's resource portfolio must be designed to have adequate and reliable resources available to meet forecasted demand at the lowest possible cost. Because the future cannot be predicted with precision, the Company must evaluate whether the portfolio resources will be adequate and reliable when actual experience departs from the forecast. Specifically, EnergyNorth considered the levels of uncertainty in the demand and sendout forecasts and developed high- and low-demand scenarios relative to the base case forecast to determine the impact a range of alternatives would have on its resource portfolio. A comparison of the average annual load additions for the base case, high- and low-demand scenarios is presented in Chart III-B-2.

(b) Development of Demand Scenarios

EnergyNorth used the results of the econometric models to develop the high and low demand scenarios. Each econometric model for customers, use per customer and sales, for both the residential and commercial/industrial classes, generates a 95 percent confidence interval around the forecasted values. For the high case, the Company used the higher bounds of the interval for each model to calculate the high demand values. Similarly, for the low case, the Company used the lower bounds of the interval for each model to calculate the low demand values.

(i) High-Demand Scenario

The high-demand scenario, shown in Chart III-B-3, results in net additions of 1,975,243 MMBtu compared to 1,416,400 MMBtu in the base case (see Chart III-B-1). For the high-demand scenario, EnergyNorth incorporates the upper bound of the 95 percent confidence interval on the number of residential customer models (A1 – A4, ARIMA and Winters Smoothing) and commercial/industrial models (D1 – D3, ARIMA and Winters Smoothing) and weighted the results as it did in the base case to forecast the high case number of customers for each class respectively. It used similar upper bounds of the residential use per customer models (B1, B2, ARIMA and Winters Smoothing) and commercial/industrial models (E1 – E3 and ARIMA) and weighted the results to forecast the higher case use per customer for each class. It used the upper bound of the confidence interval on the residential sales models (C1, C2 and ARIMA) and commercial/industrial models (F1 - F3 and ARIMA) and weighted the results to forecast sales. Finally, it combined 50/50 the results of the calculated sales, based on the weighted average number of customers and use per customer, and the weighted results of the sales forecast models to determine the overall high case forecast.

(ii) Low-Demand Scenario

The low-demand scenario, shown in Chart III-B-4 , results in net additions of 877,322 MMBtu compared to 1,416,400 MMBtu in the base case (see Chart III-B-1). For the low-demand scenario, EnergyNorth incorporated the lower bound of the 95 percent confidence interval on the number of residential customer models (A1 – A4, ARIMA and Winters Smoothing) and commercial/industrial models (D1 – D3, ARIMA and Winters Smoothing) and weighted the results as it did in the base case to forecast the low case number of customers for each class respectively. It used similar lower bounds of the residential use per customer models (B1, B2, ARIMA and Winters Smoothing) and commercial/industrial models (E1 – E3 and ARIMA) and weighted the results to forecast the lower case use per customer for each class. It used the lower bound of the confidence interval on the residential sales models (C1, C2 and ARIMA) and commercial/industrial models (F1 - F3 and ARIMA) and weighted the results to forecast sales. Finally, it combined 50/50 the results of the calculated sales, based on the weighted average number of customers and use per customer, and the weighted results of the sales forecast models to determine the overall low case forecast.

6. Transportation Migration

(a) Introduction

With the introduction of the EnergyNorth's commercial/industrial (C&I) transportation program in 2001, EnergyNorth has gained a number of years of experience with unbundled transportation service in New Hampshire. See Chart III-B-5 for the Company's transportation customer activity since 2001. EnergyNorth currently has in place a comprehensive customer-choice program that provides C&I customers with an opportunity to share in the benefits provided by increased competition in the retail market for natural gas.

(b) Impact of Transportation Migration on Sendout Requirements

The Company's resource portfolio is currently structured to have a high level of flexibility to adapt to changing market conditions and regulatory obligations. This is especially true with respect to the Company's domestic gas commodity commitments.

Generally speaking, EnergyNorth enters into agreements that allow it the flexibility to eliminate up to 100 percent of its existing domestic gas commodity purchases in less than a twelve-month period. With respect to capacity resources, EnergyNorth currently has an obligation to plan for the needs of firm customers. Therefore, the Company plans for the needs of sales customers and assigns a pro-rata share of pipeline capacity, underground storage capacity and supplement resources to third-party suppliers ("Suppliers") on behalf of those sales customers who convert to Supplier Service.[5] Under the Company's Delivery Terms and Conditions, capacity is assigned to Suppliers, on behalf of migrating sales customers, in block increments based on the profile of the aggregated customer group served by the Supplier (rather than on a customer-by-customer basis). The Supplier is assigned an initial block of capacity that is subject to monthly changes consistent with increases or decreases (in increments of 200 MMBtu) in the customer load served by the Supplier. EnergyNorth retains recall rights on the capacity contracts that are released to Suppliers on behalf of their customers to ensure that the capacity remains available to serve load within the EnergyNorth service territory. In addition, the Company monitors the addition of transportation customers, who elect Supplier Service directly and are not eligible for mandatory capacity assignment. . For EnergyNorth, the customer load opting directly for Supplier Service (without first becoming a Sales Service customer) is relatively small in proportion to the Company's overall firm sendout. For the annual period May 2003 through April 2004, such load represented approximately 1.4% of the Company's total firm sendout and for

[5] In accordance with the Company's Delivery Terms and Conditions, new customers (as defined by a meter location) who have not previously been served by the Company as a sales customer, may opt directly to Supplier Service, and therefore, are not eligible for mandatory capacity assignment.

the annual period May 2004 through April 2005 there were no new customers who opted to go directly to Supplier Service. For the period May 2005 through April 2006, one customer representing less than 0.03% of the Company's total load went directly to Supplier Service

On March 3, 2006, the Commission issued an Order of Notice in docket DG 06-33 regarding Northern Utilities' proposal regarding planning for Grandfathered Customer transportation load. KeySpan was made a mandatory party. During the course of that proceeding, the Company agreed to include in its IRP filing a discussion of the issues raised by Northern Utilities with regard to whether it is appropriate to begin planning for all or at least a portion of grandfathered customers' gas supply needs.[6] As noted above, EnergyNorth is not currently responsible for planning for the gas supply needs of Grandfathered Customers. Rather, the Company's obligation is limited to ensuring adequate on-system capacity for these customers.

The Company has considered the Northern Utilities proposal and believes that there are two key factors that must be seriously considered before a change in the Commission's policy regarding an LDC's obligation to plan for the upstream capacity resource requirements of Grandfathered customers is implemented. First: does the level of grandfathered transportation load and the historical performance of marketers supplying that load threaten the reliability of the local distribution system? And second: What is the appropriate cost recovery mechanism for the cost of planning for the upstream capacity requirements of Grandfathered Customers.

[6] Under the Northern proposal, Northern would plan for 30% of the peak day requirement of Grandfathered customers and the cost of that capacity would be borne solely by those Grandfathered customers.

At this time, based on the historical performance of Grandfathered Customers and the volumes represented by those customers, EnergyNorth does not believe that a change in the Commission's unbundling policy as it applies to EnergyNorth is warranted. First, as noted above, Grandfathered Customer load has remained constant since 2003/04. Second, the Company reviewed the daily delivery history of Suppliers doing business on the Company's system during the winter periods of November through March for the years 2003 through 2006.[7] As shown in Charts III-B-6, III-B-7 and III-B-8 there have been minimal delivery failures attributable to underdeliveries by Suppliers on behalf of transportation customers. Moreover, it is impossible to separate the underdeliveries for Grandfathered Customers deliveries from the non-Grandfathered Customer deliveries as Suppliers balance at the pool level.

If despite this data, the Commission determines that it is appropriate for the Company to plan for the upstream capacity needs of grandfathered customers, the Company suggests that it would be appropriate to plan for 100% of those needs rather than only a portion of it and to require that all customers pay for the cost of acquiring any necessary incremental resources. Regarding the level of need to plan for, assuming the Commission determines as a matter of policy that the Company should plan for the needs of Grandfathered Customer load to ensure system reliability, the Company can determine no practical or historical basis to choose a level less than 100% of that load. With regards to cost allocation, if the Company were responsible for planning for the capacity requirements of formerly Grandfathered Customers, the Company would include this load as part of its normal planning process and combine

[7] Because balancing is not done by individual customer, but rather, across the Supplier's "pool" of customers, the Company's review of deliveries made by a Supplier include deliveries made on behalf of both Grandfathered

this need with the needs of the Company's remaining customers. As the capacity and any associated supply would be contracted for as part of the Company's overall needs, and available for use by all customers, it would be impractical to allocate specific 'pieces' of capacity to certain customers. Accordingly, the Company would propose to have the incremental cost paid for by all customers, including Grandfathered Customers.

The Company will continue to monitor growth in new transportation load opting directly for Supplier Service to determine whether, in the future, the Company's growth forecasts should be adjusted. To the extent that the Company projects a need for incremental capacity on the peak day, the Company will consider the trend in these transportation loads as a factor in determining the best way to meet that need. In the interim, the Company will rely on the Commission approved penalties for underdeliveries by suppliers serving the Company's customers as an appropriate deterrent to prevent suppliers from failing to meet their supply obligation to customers.

C. Regression Analysis

In the second step of EnergyNorth's forecasting methodology set forth in Section III.A, above, the Company uses regression equations of daily sendout versus daily temperature for the most recent twelve months to calculate the reference-year "springboard." This serves as the most accurate starting point for EnergyNorth to forecast its future customer requirements. Once this step is completed, the incremental sendout requirements developed in Section III.B are added to the reference-year

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Customers and customers who were assigned capacity by the Company.

sendout requirements to determine EnergyNorth's total normalized forecast of customer requirements over the forecast period.

To establish normal-year springboard sendout requirements, the Company developed a linear-regression equation using data for the reference-year period May 1, 2005 through April 30, 2006[8]. Through the use of the linear-regression equation, the Company is able to normalize daily sendout. Specifically, the actual daily firm sendout is regressed against the daily effective degree day ("EDD") data provided by the Company's weather services provider, Meteorologix, EDD data lagged by one day, and a weekend dummy variable. These data elements were selected for the regression analysis since these elements have been, and continue to be, the major explanatory variables underlying EnergyNorth's sendout requirements.

In this filing, EnergyNorth has selected the Manchester, New Hampshire weather station as the source of the weather data that is used as the principal explanatory variable in its regression equations. The Manchester weather station is close to the center of the Company's service territory, on a load-weighted basis, and it does not have temperature biases that other weather stations (e.g. Concord) have due to topography. Specifically, the Company used the EDD value that is measured for each 24-hour period of 10 a.m. to 10 a.m., which constitutes KeySpan's Gas Day. EDD captures both the average temperature of the day as well as the effect that the wind has in increasing customer requirements.

Each year, EnergyNorth observes seasonal variations in the use-per-EDD requirements of its firm sales customers. These requirements increase going into the

[8] The Company's design year springboard incorporates observations from the 2003/04 split year, the year in which EnergyNorth experienced a design day, as more reflective of what might occur during design weather.

heating season, plateau in the December through February time period, and then decrease in the later months of the heating season. To capture this experience within the regression equation, EnergyNorth used monthly independent variables for September through June to model this seasonal change. Each monthly variable has a coefficient of zero for all days not in its respective time period and a coefficient of the actual EDD value for the days within its time period. The resulting coefficient is then the heating increment for the given time period. The positive signs on the coefficients imply that as EDD increases, the Company's sendout requirements increase as well, which corresponds with the experience of KeySpan.

EnergyNorth also observed the increase in the explanatory power of the regression equation through the inclusion of the one-day lagged EDD value. The underlying theory of this analysis is that heating requirements increase as two consecutive days of cold weather occur, which cools down structures to a greater degree than would be experienced on a single day. The variable contains the prior day's EDD value, except for the months of July and August where this value is set to zero to reflect the fact that there is no heating requirement in the summer. The positive sign of the coefficients indicates that two days of cold weather increases the heating requirement over that experienced for one cold day.

Finally, EnergyNorth observes changes in sendout requirements between weekdays and weekends, which can be attributed to differences in load requirements occurring during the workweek as compared to the weekend. To model this, the regression equation includes a weekend dummy variable that is set to 1 on Saturdays and Sundays and 0 on weekdays. A negative coefficient for the weekend variable implies a load reduction on weekend days versus weekday days, all other factors being equal. The functional form of the equation is given in Chart III-C-1. Chart III-C-2 sets forth the regression coefficients for the EnergyNorth system. The adjusted R-square is 0.982, and all of the t-statistics of the independent variables are greater than 2.0, indicating that these variables are significant to the explanatory power of the equation.

This regression equation captures the observed characteristics of the Company's sendout requirements. The observed characteristics include the following: (1) sendout requirements are directly related to EDD; (2) sendout requirements change on a seasonal basis; (3) sendout requirements are affected by EDDs that occur over a multi-day period; and (4) sendout requirements differ by day of the week. Thus, EnergyNorth has developed a set of reliable regression equations to establish the basis upon which future sendout requirements can be forecast. Using its forecast of load additions and an appropriate set of daily EDD values for a design year, the Company can successfully plan its operational requirements to provide a low-cost, adequate and reliable supply of natural gas to its customers.

D. Normalized Forecasts of Customer Requirements By Year

In the third step of the Company's forecasting methodology set forth in Section III.A, above, the Company combines the May 2005 – April 2006 reference-year sendout, which is derived from the regression analysis, with the annual incremental sendout forecast discussed in Section III.B, to yield the following forecast of customer requirements under normal weather conditions:

Base Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,441,300	9,757,800	9,904,300	10,125,700	10,377,200
Non-Heating Season	3,813,000	3,950,100	4,064,600	4,184,600	4,321,900
Total	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100
Per-Annum Growth		3.4 %	1.9 %	2.4 %	2.7 %

The heating season is defined as the months of November through March; the non-heating season is defined as the months of April through October.

High Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,691,000	10,114,200	10,341,000	10,647,900	10,986,400
Non-Heating Season	3,957,600	4,155,700	4,318,400	4,488,600	4,677,000
Total	13,648,600	14,269,900	14,659,400	15,136,500	15,663,400
Per-Annum Growth		4.6 %	2.7 %	3.3 %	3.5 %

Low Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,179,000	9,394,000	9,465,300	9,606,700	9,777,500
Non-Heating Season	3,659,300	3,734,700	3,800,500	3,870,000	3,955,500
Total	12,838,300	13,128,700	13,265,800	13,476,700	13,733,000
Per-Annum Growth		2.3 %	1.0 %	1.6 %	1.9 %

E. Planning Standards

In the fourth step of the Company's forecasting methodology, the Company performs a cost-benefit analysis to determine the appropriate design-day and design-year planning standards to develop a least-cost reliable supply portfolio over the forecast period.

1. Incorporation of the Monte Carlo Methodology

a. Background

In its previous IRP filing, the Company relied on a cost/benefit analysis methodology for the purposes of establishing design planning standards. This cost/benefit methodology used, as input data, time series of actual EDD observations that begin in January 1981 to estimate frequencies of occurrence of two types of extreme weather events: a design day and a design year. These two types of standards are significant in that the design day standard determines the most cost-effective amount of transportation capacity (both interstate and supplemental) and the design year standard determines the most cost-effective amount of storage supply to maintain to ensure reliable service to the Company's customers.

The design day standard, which specifies the most cost-effective amount of transportation capacity (both interstate and supplemental), has been based on the statistical distribution of the coldest day of each calendar year. The design year standard, which specifies the most cost-effective amount of storage supply, has been based on the statistical distribution of the total EDDs in each calendar year. The mean and standard deviation of the normal distribution of each of these data sets has been used as the weighing factor in the probability-weighted 'benefit' estimate, i.e. the value of the avoidance of damages were the Company to plan for a design day/year lower than what might occur.

b. The Theory of the Company's Monte Carlo Methodology

For its 2006 IRP, KeySpan has used a Monte Carlo simulation method to generate synthetic daily EDD values for Manchester, NH for purposes of establishing design planning standards. The application of this Monte Carlo method provides the Company with a much larger time series of daily EDD values on which to base the theoretical 'benefit' values of its cost/benefit analysis.

The Monte Carlo methodology generally implies the generation of a dataset of synthetic values, larger than a given dataset of actual observations, based on the observed statistical properties of the actual dataset. The larger size of the synthetic dataset (3,000 simulated years) can assist in the determination of the likelihood of extreme weather events, such as those the Company seeks to define in its cost/benefit analysis of its design standards.

In developing a time series of daily EDD values much larger than the Company's existing actual historical observations from 1981-present, greater consideration had to be given than to generate 365 random values for each year of the synthetic dataset. First, consideration of the seasonality of EDD values had to be given. Second, consideration of the interdependence of one day's EDD value with the prior day's value had to be given, as well. To generate its set of synthetic data values, the Company chose to model its EDD data using a first-order autoregressive process (denoted AR(1)). Such a model has been commonly assumed for meteorological time series.

Letting X_t denote the EDD value on the t^{th} day, the AR(1) process requires that the conditional probability distribution of X, given the past record of observed EDD, X_{t-1},

X_{t-2}, . . ., depends only on X_{t-1}, the observed EDD value for the previous day. This property can be expressed as:

$$X_t - \mu = \Phi(X_{t-1} - \mu) + \epsilon_t, \qquad (1)$$

where the daily EDD values are expressed in terms of deviations from their common mean μ, and Φ denotes the first-order autocorrelation coefficient. The error terms (ϵ_t) in equation (1) are assumed to constitute a "white-noise process"; that is, they are uncorrelated random variables with zero mean and constant variance σ_ϵ^2. It is further assumed that the ϵ_t, are normally distributed [denoted $N(0, \sigma_\epsilon^2)$].

The first-order autocorrelation coefficient Φ measures the degree of dependence between the EDD values on consecutive days, X_{t-1} and X_t. A value of $\Phi = 0$ implies that X_{t-1} and X_t are uncorrelated (i.e., X_t is completely unpredictable from the past record of daily EDD), whereas a value of $\Phi = 1$ or -1 implies that the X_t are perfectly correlated (i.e., X_t is completely predictable). For daily EDD time series, typically $0 < \Phi < l$, meaning that the X_t are positively, but not perfectly, correlated. An AR(1) process is stationary (i.e., all the joint probability distributions of the X, are time invariant) if $| \Phi | < 1$. Although daily EDD time series are clearly nonstationary because seasonal cycles are present, the stationarity assumption is a reasonable approximation when dealing with a single month. Besides this day-to-day stationarity, it is also assumed that the monthly time series are stationary from year to year; in other words, that the climate over its recent history (since 1981, say) has not changed in a statistical sense.

The requirement that the error term ϵ_t is normally distributed implies that the daily EDD X_t also is normally distributed. Letting σ^2 denote the variance of X_t, it is straightforward to show that σ^2 is related to σ_ϵ^2, the variance of an error term, by

$$\sigma_\epsilon^2 = (1 - \Phi^2)\,\sigma^2 \qquad (2)$$

We see by equation (2), that the stronger the dependence between X_{t-1} and X_t, the greater the reduction in the variance of an error term relative to the variance of daily EDD. More importantly, (2) implies that an AR(1) process can be completely characterized in terms of three parameters, μ and, say Φ and σ^2.

c. The Application of the Company's Monte Carlo Methodology: Introduction

To determine the three parameters, μ, Φ and σ^2 required for the AR(1) process, while considering the seasonality of EDD values, the Company began by determining the mean observed EDD value for each calendar day within its existing dataset (Figure 1).

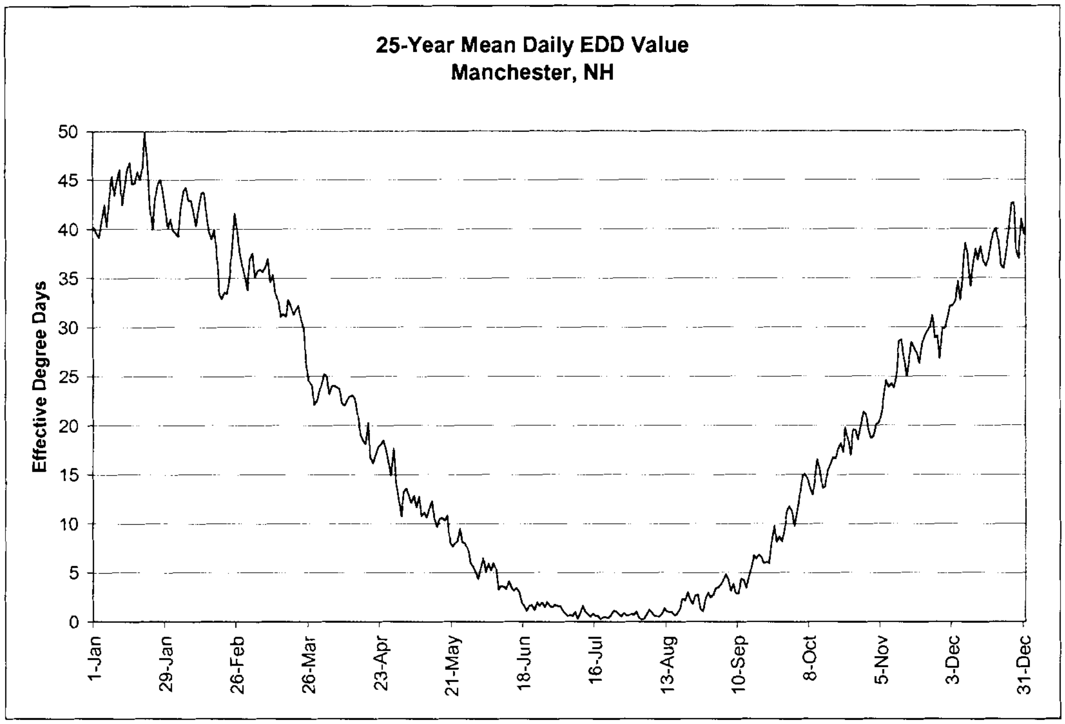

Figure 1: 25-Year Mean Observed EDD Value By Calendar Day

To calculate its synthetic EDD series, the Company first divided its process into two subsets: heating season (October-May) and non-heating season (June-September). This was necessary to properly account for the fact that EDD values are not a continuous number series, i.e. while, theoretically EDD values can grow infinitely positive, by definition, they have a lower limit of zero.

d. The Application of the Company's Monte Carlo Methodology: Heating Season

For each day of observed EDD for the heating season, the Company then computed the difference from that day's actual EDD and the 25-year mean EDD value for the same calendar day. From these daily deviation values, the Company calculated mean and standard deviation values, for each calendar month, to establish the μ and σ^2 parameters required for its AR(1) process. From the time series of these daily deviation values, the Company calculated Pearson correlation coefficient, for each calendar month, to establish the Φ parameter required for its AR(1) process.

	μ	Σ	Φ
October	0.00	7.17	0.541
November	0.00	8.68	0.536
December	0.00	9.86	0.631
January	0.00	11.54	0.671
February	0.00	10.10	0.618
March	0.00	8.65	0.583
April	0.00	7.61	0.555
May	0.00	5.91	0.499

Table 1: μ, Φ and σ^2 parameters for the AR(1) heating season process

To create 3,000 years of synthetic daily EDD time series, the Company generated 243 random EDD deviation values (October 1st – May 31st) denoted by X'_1, $X'_2, \ldots, X'_n$, from the AR(1) process and added each day's deviation to the established mean EDD value for the same calendar day. The initial daily EDD deviation value (for the day of October 1st), X'_1 was produced from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator. Each subsequent daily EDD deviation value, X'_n, was produced using Equations (1) and (2) from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator and the first-order autocorrelation coefficient Φ.

e. The Application of the Company's Monte Carlo Methodology: Non-Heating Season

To account for the fact that EDD values will frequently be zero during the non-heating season months of June through September, the Company modified the approach for the heating season and determined the actual monthly values of μ and σ, by matching the tail end of each month's actual observed distribution over the 25-year historical period with a normal distribution. Therefore, the Company could bypass the step of applying random errors to the 25-year mean EDD value for each calendar day and generate the synthetic values themselves with the and σ values and the monthly Pearson correlation coefficients of the deviation-from-mean values.

	μ	Σ	Φ
June	1.00	5.50	0.541
July	-1.50	3.00	0.536
August	-1.20	4.50	0.631
September	4.50	6.50	0.671

Table 2: μ, Φ and σ^2 parameters for the AR(1) non-heating season process

To create 3,000 years of synthetic daily EDD time series, the Company generated 122 random EDD values (June 1st – September 30th) denoted by X'_1, X'_2,..., X'_n, from the AR(1) process. The initial daily EDD value (for the day of June 1st), X'_1 was produced from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator. Each subsequent daily EDD value, X'_n, was produced using Equations (1) and (2) from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator and the first-order autocorrelation coefficient Φ.

f. Results of the Company's Monte Carlo Methodology: Peak Day

For each of the 3,000 synthetic heating seasons (October-May), the greatest EDD value was selected, with the minimum value of 52 EDD, the maximum value of 95 EDD, the mean value of 66.98 EDD and the standard deviation of 5.99 EDD. These statistics can be compared to the actual observed values from 1981-2005: the minimum value of 55 EDD, the maximum value of 80 EDD, the mean value of 68 EDD and the standard deviation of 6.39 EDD.

Table 3 below lists the EDD values from 67 through 90, along with the number of occurrences exceeding each EDD value, and the probability of exceeding each EDD value, based on the synthetic dataset.

Greatest Heating Season EDD Value	Number of Occurrences Exceeding	Probability of Exceeding
67	1,288	0.4293
68	1,088	0.3627
69	903	0.3010
70	769	0.2563
71	631	0.2103
72	503	0.1677
73	403	0.1343
74	323	0.1077
75	264	0.0880
76	207	0.0690
77	163	0.0543
78	125	0.0417
79	93	0.0310
80	74	0.0247
81	57	0.0190
82	43	0.0143
83	29	0.0097
84	24	0.0080
85	16	0.0053
86	11	0.0037
87	8	0.0027
88	3	0.0010
89	3	0.0010
90	3	0.0010

Table 3: Peak Day Results Generated From Synthetic Dataset

g. Results of the Company's Monte Carlo Methodology: Peak Years

For each of the 3,000 synthetic years, the annual total EDDs were calculated, with the minimum value of 6,021 EDD, the maximum value of 8,081 EDD, the mean value of 7,079 EDD and the standard deviation of 291.29 EDD. These statistics can be compared to the actual observed calendar year values from 1981-2005: the minimum value of 6,450 EDD, the maximum value of 7,700 EDD, the mean value of 7,108 EDD and the standard deviation of 332.38 EDD.

Table 4 below lists the EDD values from 7,100 through 8,300, along with the number of occurrences exceeding each EDD value, and the probability of exceeding each EDD value, based on the synthetic dataset.

Greatest Annual EDD Value	Number of Occurrences Exceeding	Probability of Exceeding
7,100	1,401	0.4670
7,200	989	0.3297
7,300	650	0.2167
7,400	396	0.1320
7,500	220	0.0733
7,600	113	0.0377
7,700	51	0.0170
7,800	15	0.0050
7,900	5	0.0017
8,000	3	0.0010
8,100	0	0.0000
8,200	0	0.0000
8,300	0	0.0000

Table 4: Peak Year Results Generated From Synthetic Dataset

The Company then proceeded to use the 'Probability of Exceeding' values from its synthetic dataset in its cost/benefit analyses of Design Day and Design Year determination.

2. Normal Year Standards

From Section III.C.1.g above, it was determined that the normal year is 7,079 EDD with a standard deviation of 291.29 EDD

EnergyNorth then prepared a "Typical Meteorological Year" (Chart III-E-1) by selecting, for each calendar month, the month in the Manchester, NH weather database that most closely approximated the average EDD and standard deviation for each month.

3. Design Year and Design Day Planning Standards

EnergyNorth's planning standards represent the defined weather conditions and consequent sendout requirement that must be met by the Company's resource portfolio. EnergyNorth's design year and design day standards are listed in Chart III-E-2.

Because EnergyNorth must demonstrate that there are adequate resources available to meet design conditions, while minimizing costs in a normal year, the Company periodically reassesses the appropriateness of these standards. As described below, the Company's analysis of the design year and design day standards demonstrate that these standards are appropriate.

(a) Design Day Standard

The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, EnergyNorth defines its design day standard as 80.2 EDD with a probability of occurrence of once in 42.49 years.

EnergyNorth established its design day standard using a three-step process. First, the Company performed a statistical analysis of the coldest days derived from its Monte Carlo analysis. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design day demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-day standard that would maintain reliability at the lowest cost.

For the first step, Section III.C.1.f (above), the Company identified the probability of occurrence of the coldest day of a heating season.

For the second step, EnergyNorth examined the cost of potential customer curtailments through a cost-benefit analysis. Chart III-E-3 shows the cumulative probability distribution and the frequency of occurrence of EDD levels greater than the mean peak day. Chart III-E-3 also shows, given the peak period heating coefficient of 1,463 MMBtu/EDD, the supply ("Delta Supply") required at these levels. The Company then translated these supply levels into the "Equivalent Number of Customers" that would be represented by a shortfall at a given EDD level.[9]

[9] EnergyNorth determined the equivalent number of customers using the following formula: Delta Supply/[(Heating Increment/Number of Customers)*EDD].

In the event of a service disruption, there are several types of damages that customers could experience. For example, EnergyNorth's residential customers would potentially incur re-light costs and freeze-up damages. EnergyNorth's commercial/industrial customers would potentially incur economic damages associated with the loss of production on the day of the event (which is further documented in Section III.E.2(b) - Design Year Standard).

There are three potential re-light cost values for three different building densities where the re-lights may occur: (1) congested areas; (2) moderately congested areas; and (3) non-congested areas. The re-lighting cost per establishment rises as the building density decreases to account for the increased time that is required to travel between establishments. The cost estimate for moderately congested areas was chosen as representative for EnergyNorth's planning standards.

EnergyNorth obtained a cost estimate for freeze-up damages from KeySpan's Risk Management Group. The current cost estimate of remodeling is $44,631/customer. The Company made the assumption that, in the event of freeze-up damages, only a portion of a residence would require remodeling. This provides a range of possible outcomes, due to the uncertainty of what might occur in the event of such freeze-ups. Accordingly, the Company used this cost estimate to represent the cost of a full remodel, which was then adjusted to represent the portion of the residence requiring remodeling.

Given the ratio of C&I customers to the total number of customers at year-end 2005, EnergyNorth divided the "Equivalent Number of Customers" into the number of residential and C&I customers. For the C&I customers, the Company computed the cost of the service disruption by multiplying the ratio of affected customers by the total number of C&I customers by the estimated cost of one day's service disruption to EnergyNorth's entire group of C&I customers. Since the actual number of residential customers that would suffer freeze-up damage in a real emergency is unknown, EnergyNorth analyzed three levels of damages assuming 25 percent, 50 percent, and 75 percent of potentially-affected residential customers suffer damages. The computed values for these three scenarios of probability-weighted costs of damages are presented in Chart III-E-4 and are shown graphically in Chart III-E-5.

Chart III-E-6 takes the EDD levels and the associated Delta Supply (i.e. the implicit supply shortfall – the EDDs above the mean peak day value times the overall heating increment) to estimate the costs associated with maintaining adequate deliverability at the EDD levels. The low-upgrade cost scenario is based on the cost of adding propane vaporization capacity and the high—upgrade cost scenario is based on the cost of adding 365-day interstate pipeline service (with many other potential options falling in between). This is shown graphically in Chart III-E-7. In Chart III-E-7, the cost of maintaining adequate throughput capacity and the benefit of avoiding damage costs that would be incurred in relation customer premises are compared.

The intersection of the curves sets a range of solutions for design day planning purposes from approximately 75 to 87 EDD with the center of the geometric shape located at 80.2 EDD. The Company then rounded this to the nearest integer value (80 EDD).

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The intersection of the curves sets a range of solutions for design day planning purposes from approximately 75 to 87 EDD with the center of the geometric shape located at 80.2 EDD. The Company then rounded this to the nearest integer value (80 EDD).

(b) Design Year Standard

In this filing, EnergyNorth defines its design year standard as 7,680 EDD with a probability of occurrence of once in 47.32 years.

EnergyNorth maintains a design year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonably anticipated weather conditions. If EnergyNorth were to have a shortfall in supply during the winter season, the amount of supply in deficit can be translated into an equivalent number of customers whose service would be disrupted for more than one day. For a supply disruption of a multi-day duration, service would be curtailed on a priority basis and would likely fall on commercial and industrial establishments before affecting the residential sector, since supply to the residential sector is more likely to involve health and personal safety concerns. To establish an estimated annual level of EDD for which EnergyNorth should plan, the Company compared the benefit of maintaining an adequate quantity of natural gas supply under all reasonably anticipated weather conditions to the probability-weighted cost of losses that might occur if supplies are not adequate.

EnergyNorth has established its design-year standard using a three-step process. First, the Company performed a statistical analysis of annual EDD data recorded over a historical period. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design-year demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-year standard that would maintain reliability at the lowest cost.

To complete the first step in the process of determining EnergyNorth's design-year standard, the Company relied on the results of its Monte Carlo analysis as found in Section III.C.1.g above. To evaluate the design-year standard, EnergyNorth analyzed a range of annual EDD values from the mean value to 1,200 EDD greater than the mean.

To complete the second step in the development of the design-year standard, EnergyNorth performed a cost-benefit analysis by examining the cost of potential customer curtailments in relation to the cost of maintaining adequate supplies to meet the design-year standard. Because a failure to perform on a seasonal basis would mean that adequate supplies were not available to meet customer needs, EnergyNorth views the cost of failure to deliver as the economic penalty within the service territory associated with the need to curtail gas sales for a period of time. Service would be rationed among EnergyNorth customers for a number of days in order to preserve any remaining gas supplies. EnergyNorth estimated the potential losses based on the product of the potential economic cost per day of interruption, times the number of days of interruption.

To calculate this estimate of potential losses, EnergyNorth determined the average Gross State Product per day (GSP/day) for the state of New Hampshire for 2005 from data available from the U.S. Bureau of Economic Analysis. The economic cost to EnergyNorth's customer base per day was then calculated on the basis of the total GSP/day. First, the value for the GSP/day for EnergyNorth's service territory was estimated by multiplying the GSP/day by the ratio of the number of employees within the service territory to the total number of employees within the state, based on 2005 employment data from the New Hampshire Economic and Labor Market Information

Bureau. Then, the value for the GSP/day in 2005 for EnergyNorth's customer base was estimated by multiplying the GSP/day figure for the EnergyNorth service territory by the estimated market share of natural gas in relation to all fuel types in the service territory.

To determine the number of days of interruption that a supply shortfall would represent, EnergyNorth analyzed its supply requirements at various EDD levels, assigned requirements to 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.

EnergyNorth established a baseline of the normal annual EDD (7,079) and then determined sendout requirements for the split year 2005/06 by assigning all sendout requirements below the daily deliverability of its Canadian and domestic long-haul pipeline capacity to pipeline supply; all requirements greater than its pipeline supply up to its underground storage deliverability to underground storage supplies; and all requirements above that to supplemental resources. EnergyNorth then analyzed the sendout requirements for EDD levels of 7,079 to 8,300 on 100 EDD increments. EnergyNorth computed these EDD scenarios by multiplying each of the days of its normal EDD days by the ratio of the desired annual total to 7,079 EDD. Using the same method of assignment of supply sources, EnergyNorth determined the annual shortfalls by supply source (Chart III-E-8).

Chart III-E-9 shows that the timing of when the shortfalls occur varies among the supply sources. Pipeline shortfalls occur late in the heating season. The underground storage and supplemental-resource shortfalls occur during the heating season. Chart

III-E-10 summarizes the EDD levels, the probabilities of occurrence, and the shortfall by supply type.

Analysis indicates that sendout for EnergyNorth during the heating season is 49 percent residential and 51 percent C&I. In examining its calculations of shortfalls versus the daily sendout requirements to each of these customer classes, the total daily shortfall of underground storage and supplemental supplies at all EDD levels in this study can be assigned to C&I customers. For each forecast day under each EDD scenario, the daily sendout requirement was multiplied by 51 percent to derive the C&I portion. If the day had a supply shortfall, the shortfall value was divided by the C&I requirement to derive that day's fractional amount of EnergyNorth's C&I customers that would suffer curtailment. Summing all of these values for a given EDD scenario, EnergyNorth determined the total number of day-equivalents of interruption. This value is less than or equal to the number of calendar days during which interruption occurred since not all days will have 100 percent interruption. Multiplying the number of day-equivalents by the GSP/day for the C&I customer base yields an estimate of the economic damage that would occur. Chart III-E-11 lists the EDD levels, the probabilities of occurrence, the days of interruption, the cost of the interruption, the probability-weighted cost of the interruption, and the quantity of interrupted winter supply (underground storage and supplemental resources).

There are two damages scenarios presented here: one where 25 percent of the C&I establishments are actually affected, and one where 75 percent of the establishments are affected. Chart III-E-11 also sets forth two scenarios of satisfying the deficit: a 365-day long-haul capacity contract based on the required incremental throughput capacity, and a 365-day short-haul capacity contract meeting the required incremental throughput capacity plus an underground storage contract with adequate capacity to meet the required incremental winter volume. Chart III-E-12 demonstrates that a planning range of 7,590 to 7,740 EDD, with the center of the geometric shape located at 7,680 EDD is appropriate.

F. Forecasts of Design Year Customer Requirements By Year

In the fifth and final step of the Company's forecasting methodology set forth in Section III.A above, the Company uses the applicable design day and design year planning standards to determine the design day and design year sendout requirements. To accomplish this, the Company combines the 2005/06 reference-year sendout, which is derived from the regression analysis, with the annual incremental sendout forecast discussed in Section III.B, to yield the following forecast of customer requirements under design weather conditions:

Base Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	**2007-08**	**2008-09**	**2009-10**	**2010-11**
Heating Season	10,451,700	10,795,100	10,946,700	11,183,400	11,452,000
Non-Heating Season	4,089,700	4,232,000	4,350,800	4,475,400	4,617,800
Total	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800
Per-Annum Growth		3.3 %	1.8 %	2.4 %	2.6 %

High Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	**2007-08**	**2008-09**	**2009-10**	**2010-11**
Heating Season	10,764,700	11,221,900	11,458,800	11,786,400	12,147,900
Non-Heating Season	4,264,200	4,469,300	4,638,200	4,814,700	5,009,900
Total	15,028,900	15,691,200	16,097,000	16,601,100	17,157,800
Per-Annum Growth		4.4 %	2.6 %	3.1 %	3.4 %

Low Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	10,123,200	10,358,400	10,430,400	10,582,000	10,765,200
Non-Heating Season	3,904,200	3,983,100	4,051,700	4,124,400	4,213,500
Total	14,027,400	14,341,500	14,482,100	14,706,400	14,978,700
Per-Annum Growth		2.2 %	1.0 %	1.5 %	1.9 %

KeySpan Sendout Requirements Forecast
EnergyNorth Natural Gas, Inc.
2006/07 - 2010/11 Base Case

Normal Weather	2006/07	2007/08	2008/09	2009/10	2010/11	Average Increment Or Percent	Total Increment Or Percent
Sendout (MMBtu)							
Residential	5,804,058	6,012,112	6,136,364	6,253,751	6,387,670	145,903	583,612
Commercial & Industrial	7,450,242	7,695,788	7,832,536	8,056,549	8,311,430	215,297	861,188
Traditional Market	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100	361,200	1,444,800
NGV	0	0	0	0	0	0	0
Seasonal	0	0	0	0	0	0	0
Total	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100	361,200	1,444,800
Growth Rate (%)							
Residential		3.58%	2.07%	1.91%	2.14%	2.43%	9.71%
Commercial & Industrial		3.30%	1.78%	2.86%	3.16%	2.77%	11.10%
Traditional Market		3.42%	1.90%	2.44%	2.72%	2.62%	10.49%
NGV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Seasonal		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		3.42%	1.90%	2.44%	2.72%	2.62%	10.49%

Design Weather	2006/07	2007/08	2008/09	2009/10	2010/11	Average Increment Or Percent	Total Increment Or Percent
Sendout (MMBtu)							
Residential	6,367,679	6,590,696	6,720,001	6,843,060	6,983,324	153,911	615,645
Commercial & Industrial	8,173,721	8,436,404	8,577,499	8,815,740	9,086,476	228,189	912,755
Traditional Market	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800	382,100	1,528,400
NGV	0	0	0	0	0	0	0
Seasonal	0	0	0	0	0	0	0
Total	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800	382,100	1,528,400
Growth Rate (%)							
Residential		3.50%	1.96%	1.83%	2.05%	2.34%	9.35%
Commercial & Industrial		3.21%	1.67%	2.78%	3.07%	2.68%	10.73%
Traditional Market		3.34%	1.80%	2.36%	2.62%	2.53%	10.13%
NGV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Seasonal		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		3.34%	1.80%	2.36%	2.62%	2.53%	10.13%

Chart III-B-1

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Base Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	198,849	176,048	139,114	155,256	669,267	167,317
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	174,844	152,043	115,109	131,251	573,247	143,312
Commercial/Industrial	259,919	220,901	273,234	303,371	1,057,425	264,356
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	381,195	319,376	334,775	381,054	1,416,400	354,100

Chart III-B-2

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Base Case vs. Low Case and High Case

2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

		2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS							
Base Case vs Low Case							
	Base Case						
	Residential	174,844	152,043	115,109	131,251	573,247	143,312
	Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
	Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
	Low Case						
	Residential	161,170	140,073	100,844	113,637	515,723	128,931
	Commercial/Industrial	62,664	55,312	106,050	137,571	361,599	90,400
	Traditional Total	223,834	195,385	206,894	251,208	877,322	219,330
	Difference (Base vs. Low)						
	Residential	13,674	11,970	14,266	17,615	57,524	14,381
	Commercial/Industrial	143,687	112,021	113,616	112,231	481,554	120,389
	Traditional Total	157,360	123,991	127,881	129,846	539,078	134,770
	Difference as % of Base Case						
	Residential	7.82%	7.87%	12.39%	13.42%	10.03%	10.03%
	Commercial/Industrial	69.63%	66.94%	51.72%	44.93%	57.11%	57.11%
	Traditional Total	41.28%	38.82%	38.20%	34.08%	38.06%	38.06%
Base Case vs High Case							
	Base Case						
	Residential	174,844	152,043	115,109	131,251	573,247	143,312
	Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
	Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
	High Case						
	Residential	190,133	165,488	131,184	151,023	637,828	159,457
	Commercial/Industrial	353,008	282,460	336,395	365,553	1,337,415	334,354
	Traditional Total	543,140	447,948	467,580	516,576	1,975,243	493,811
	Base vs. High						
	Residential	(15,289)	(13,445)	(16,075)	(19,772)	(64,581)	(16,145)
	Commercial/Industrial	(146,656)	(115,127)	(116,729)	(115,750)	(494,262)	(123,566)
	Traditional Total	(161,946)	(128,572)	(132,804)	(135,522)	(558,843)	(139,711)
	% of Base Case						
	Residential	-8.74%	-8.84%	-13.97%	-15.06%	-11.27%	-11.27%
	Commercial/Industrial	-71.07%	-68.80%	-53.14%	-46.34%	-58.62%	-58.62%
	Traditional Total	-42.48%	-40.26%	-39.67%	-35.56%	-39.46%	-39.46%

Chart III-B-3

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
High Case
2006-2010

(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)

2006 FORECAST

	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	214,138	189,493	155,189	175,028	733,848	183,462
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	190,133	165,488	131,184	151,023	637,828	159,457
Commercial/Industrial	406,576	336,028	389,963	419,121	1,551,687	387,922
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	353,008	282,460	336,395	365,553	1,337,415	334,354
Traditional Total	543,140	447,948	467,580	516,576	1,975,243	493,811
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	543,140	447,948	467,580	516,576	1,975,243	493,811

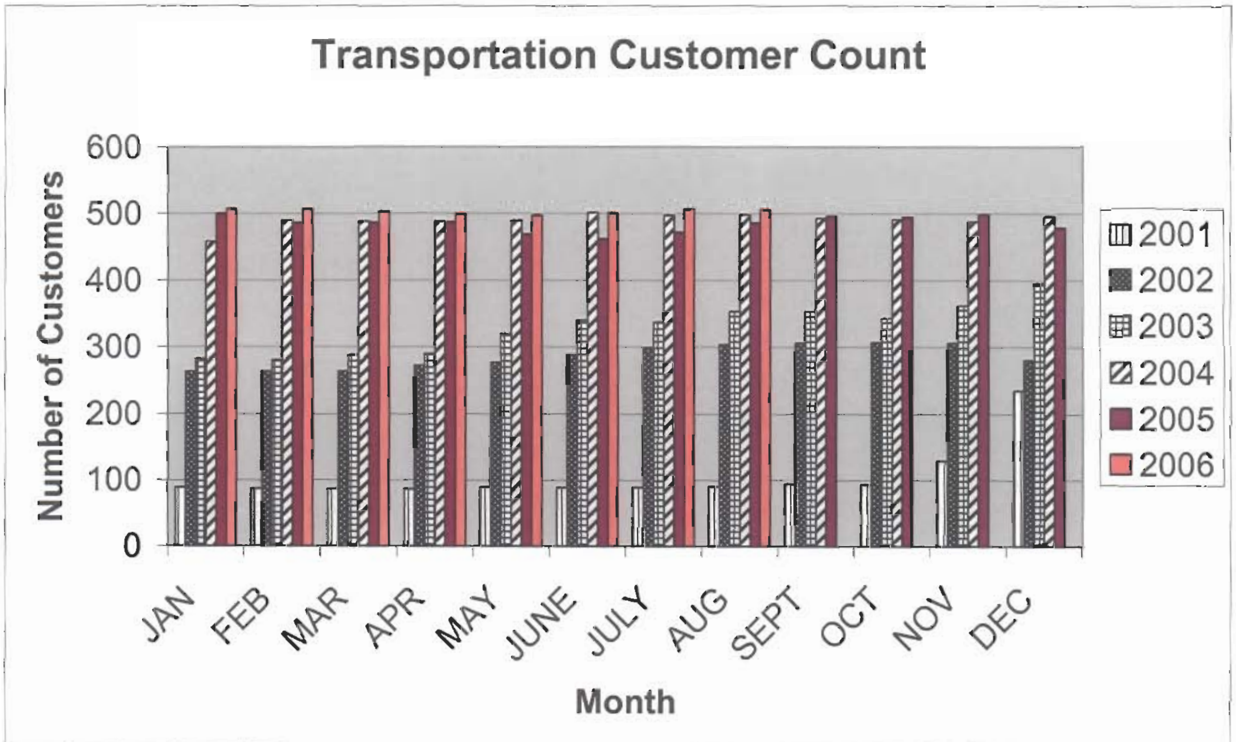
Chart III-B-4

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Low Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	185,175	164,078	124,849	137,642	611,743	152,936
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	161,170	140,073	100,844	113,637	515,723	128,931
Commercial/Industrial	116,232	108,880	159,618	191,139	575,871	143,968
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	62,664	55,312	106,050	137,571	361,599	90,400
Traditional Total	223,834	195,385	206,894	251,208	877,322	219,330
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	223,834	195,385	206,894	251,208	877,322	219,330

Chart III-B-5



Transportation Customer Count
600
500
400
300
200
100
0
Number of Customers
2001
2002
2003
2004
2005
2006
JAN
FEB
MAR
APR
MAY
JUNE
JULY
AUG
SEPT
OCT
NOV
DEC
Month

Chart III-B-6

KeySpan Energy Delivery
Energy North
Marketer Underdeliveries
Peak Season Periods
Nov 03 - Mar 04

(MMBtu)

Marketer:	Daily Metered Service A	B	C	D	E	F	Total Under-Deliv	Total Marketer Deliveries	% Imbalance	Non-Daily Metered Service A	B	C	D	E	F	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date																		
11/6/2003	0	144	0	0	0	0	144	5,199	2.77%	0	0	0	0	0	0	0	n/a	n/a
11/10/2003	0	169	0	0	0	0	169	6,566	2.57%	0	0	0	0	0	0	0	n/a	n/a
11/11/2003	0	197	0	0	0	0	197	6,240	3.16%	0	0	0	0	0	0	0	n/a	n/a
11/18/2003	0	1	0	0	0	0	1	6,847	0.01%	0	0	0	0	0	0	0	n/a	n/a
12/1/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	7	0	7	2,318	0.30%
12/2/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	6	0	6	2,929	0.20%
12/3/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	3	0	3	2,781	0.11%
12/4/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	30	0	30	2,742	1.09%
12/5/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	30	0	30	2,552	1.18%
12/25/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	48	0	0	48	2,365	2.03%
12/26/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	14	0	0	14	2,688	0.52%
12/27/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	12	0	0	12	2,690	0.45%
12/28/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	11	0	0	11	2,633	0.42%
1/1/2004	0	0	0	36	83	282	401	3,792	10.57%	0	0	0	0	0	0	0	n/a	n/a
1/4/2004	0	1	0	0	0	0	1	5,262	0.02%	0	0	0	0	0	0	0	n/a	n/a
1/5/2004	0	0	0	1	0	0	1	6,639	0.02%	0	0	0	0	0	0	0	n/a	n/a
1/10/2004	0	0	0	0	0	0	0	n/a	n/a	0	0	0	11	8	0	19	4,757	0.40%
1/24/2004	0	0	0	0	0	0	0	n/a	n/a	0	1	0	0	0	0	1	4,518	0.02%
1/27/2004	0	4	0	0	0	0	4	178	2.25%	0	0	0	0	0	0	0	n/a	n/a
1/28/2004	0	2	0	0	0	0	2	7,721	0.03%	0	0	0	0	0	0	0	n/a	n/a
1/29/2004	0	0	0	0	41	0	41	7,616	0.54%	0	0	0	0	0	0	0	n/a	n/a
1/31/2004	0	0	0	26	0	0	26	6,419	0.41%	0	0	0	0	0	0	0	n/a	n/a
2/3/2004	0	0	0	0	0	0	0	n/a	n/a	n/a	0	0	284	0	0	284	2,609	10.89%
2/12/2004	0	2	0	0	0	0	2	7,284	0.03%	n/a	0	0	0	0	0	0	n/a	n/a
2/16/2004	0	6	0	0	0	0	6	8,065	0.07%	n/a	0	0	0	0	0	0	n/a	n/a
2/17/2004	36	1	0	25	28	0	90	7,173	1.25%	n/a	0	0	0	0	0	0	n/a	n/a
2/20/2004	0	5	0	0	0	0	5	6,031	0.08%	n/a	0	0	0	0	0	0	n/a	n/a
2/22/2004	0	1	0	0	0	0	1	6,606	0.02%	n/a	0	0	0	0	0	0	n/a	n/a
3/8/2004	0	6	0	0	0	0	6	6,780	0.09%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/10/2004	0	6	0	0	0	0	6	6,625	0.09%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/12/2004	0	3	0	0	0	0	3	6,605	0.05%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/13/2004	0	4	0	0	0	0	4	6,198	0.06%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/19/2004	0	2	0	0	0	0	2	6,746	0.03%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/21/2004	0	2	0	0	0	0	2	6,008	0.03%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/22/2004	0	12	0	0	0	0	12	7,221	0.17%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/23/2004	0	12	0	0	0	0	12	6,984	0.17%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/24/2004	0	9	0	0	0	0	9	6,490	0.14%	n/a	n/a	0	0	0	0	0	n/a	n/a
Total Nov 03 - Mar 04	36	589	0	88	152	282	1,147	157,295	0.73%	0	1	0	380	84	0	465	35,582	1.31%

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

Chart III-B-7

KeySpan Energy Delivery

Energy North

Marketer Underdeliveries

Peak Season Periods

Nov 04 - Mar 05

(MMBtu)

Marketer:	Daily Metered Service A	B	C	D	E	F	G	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date										
11/9/2004	n/a	n/a	0	1	72	0	0	73	6,959	1.05%
12/5/2004	n/a	n/a	34	57	228	33	0	352	5,275	6.67%
12/7/2004	n/a	n/a	5	48	0	0	0	53	6,395	0.83%
12/20/2004	n/a	n/a	0	39	0	105	0	144	7,697	1.87%
12/21/2004	n/a	n/a	0	62	0	79	0	141	7,206	1.96%
1/12/2005	n/a	n/a	0	46	237	0	0	283	5,834	4.85%
1/31/2005	n/a	n/a	0	0	40	0	0	40	6,895	0.58%
Total Nov 04 - Mar 05	n/a	n/a	39	253	577	217	0	1,086	46,261	2.35%

Marketer:	Non-Daily Metered Service A	B	C	D	E	F	G	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date										
11/9/2004	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/5/2004	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/7/2004	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/20/2004	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/21/2004	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/12/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/31/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
Total Nov 04 - Mar 05	n/a	n/a	0	0	0	0	0	0	n/a	n/a

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

KeySpan Energy Delivery
Energy North
Marketer Underdeliveries
Peak Season Periods
Nov 05 - Mar 06

(MMBtu)

Daily Metered Service

Marketer:	A	B	C	D	E	F	G	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date										
11/2/2005	n/a	n/a	0	68	0	0	0	68	6,758	1.01%
11/11/2005	n/a	n/a	0	69	0	0	0	69	6,232	1.11%
11/12/2005	n/a	n/a	0	49	0	0	0	49	4,430	1.11%
11/24/2005	n/a	n/a	0	152	0	0	0	152	4,039	3.76%
11/25/2005	n/a	n/a	0	43	0	0	0	43	4,779	0.90%
12/4/2005	n/a	n/a	3	129	7	0	0	139	5,822	2.39%
12/31/2005	n/a	n/a	0	0	0	16	0	16	4,595	0.35%
1/1/2006	n/a	n/a	0	0	0	432	0	432	3,830	11.28%
1/15/2006	n/a	n/a	10	58	0	210	33	311	5,637	5.52%
2/18/2006	n/a	n/a	0	0	0	825	0	825	4,624	17.84%
2/28/2006	n/a	n/a	0	68	0	0	0	68	7,140	0.95%
3/30/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a
Total Nov 04 - Mar 05	n/a	n/a	13	636	7	1,483	33	2,172	57,886	3.75%

Non-Daily Metered Service

Marketer:	A	B	C	D	E	F	G	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date										
11/2/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/11/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/12/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/24/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/25/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/4/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/31/2005	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/1/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/15/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a
2/18/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a
2/28/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a
3/30/2006	n/a	n/a	0	0	0	1	0	1	1,703	0.06%
Total Nov 04 - Mar 05	n/a	n/a	0	0	0	1	0	1	1,703	0.06%

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

Functional Form of Regression Equation

	Coefficient
Firm Sendout = f (	Base Load,
	September EDD,
	October EDD,
	November EDD,
	December EDD,
	January EDD,
	February EDD,
	March EDD,
	April EDD,
	May EDD,
	June EDD,
	Lagged EDD,
	Weekend Dummy)

In the regression equation, the units of the coefficients are in MMBtu/day for the Base Load and the Weekend Dummy and in MMBtu/EDD for the EDD-related variables.

Regression Coefficients for KeySpan

Coefficient	EnergyNorth
Base Load	9,446.702
September EDD	349.568
October EDD	896.779
November EDD	1,100.642
December EDD	1,259.716
January EDD	1,264.454
February EDD	1,251.669
March EDD	1,180.541
April EDD	926.163
May EDD	793.901
June EDD	404.185
Lagged EDD	216.750
Weekend Dummy	-2,264.001
R-squared	0.990
Std Error of the Equation	2,483.750

Chart III-E-1

Average Monthly EDD and Average of Monthly Standard Deviations For The Manchester, NH Weather Site

	EDD	Standard Deviation
January	1,348	11.0
February	1,106	10.2
March	977	9.5
April	601	8.0
May	310	6.0
June	83	3.5
July	19	1.3
August	39	2.1
September	163	5.0
October	504	7.4
November	780	9.0
December	1,149	9.7
Total	7,079	

Chart III-E-2

Design Year and Design Day Criteria

	Manchester, NH Weather Site
Design Year EDD	7,680
Frequency of Occurrence	1/47.32 years
Design Day EDD	80.2
Frequency of Occurrence	1/42.49 years

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Peak Day =	67.0	EDD
Std Dev Peak Day =	6.0	EDD
Heating Increment =	1,463	MMBtu/EDD
No. of Firm Customers =	80,303	

EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	EDD Excess	Delta Supply (MMBtu)	Requirements Of An Average Customer At EDD Level (MMBtu/cust)	Equivalent Number of Customers
67.0		0.4293	2.33	0.0	23	1.22	19
68.0		0.3627	2.76	1.0	1,487	1.24	1,200
69.0		0.3010	3.32	2.0	2,950	1.26	2,346
70.0		0.2563	3.90	3.0	4,413	1.28	3,460
71.0		0.2103	4.75	4.0	5,877	1.29	4,542
72.0		0.1677	5.96	5.0	7,340	1.31	5,594
73.0		0.1343	7.44	6.0	8,803	1.33	6,618
74.0		0.1077	9.29	7.0	10,266	1.35	7,614
75.0		0.0880	11.36	8.0	11,730	1.37	8,583
76.0		0.0690	14.49	9.0	13,193	1.38	9,526
77.0		0.0543	18.40	10.0	14,656	1.40	10,446
78.0		0.0417	24.00	11.0	16,120	1.42	11,341
79.0		0.0310	32.26	12.0	17,583	1.44	12,214
80.0		0.0247	40.54	13.0	19,046	1.46	13,065
81.0		0.0190	52.63	14.0	20,509	1.48	13,895
82.0		0.0143	69.77	15.0	21,973	1.49	14,705
83.0		0.0097	103.45	16.0	23,436	1.51	15,496
84.0		0.0080	125.00	17.0	24,899	1.53	16,267
85.0		0.0053	187.50	18.0	26,363	1.55	17,020
86.0		0.0037	272.73	19.0	27,826	1.57	17,756
87.0		0.0027	375.00	20.0	29,289	1.59	18,475
88.0		0.0010	1000.00	21.0	30,753	1.60	19,178
89.0		0.0010	1000.00	22.0	32,216	1.62	19,865
90.0		0.0010	1000.00	23.0	33,679	1.64	20,536
80.2		0.0235	42.49	(EDD Level MINUS Mean Peak)	(EDD Excess TIMES Heating Increment) (MMBtu)	(Heating Increment DIVIDED BY No. of Firm Customers TIMES EDD Level)	(Delta Supply DIVIDED BY Requirements of Average Customer)

Chart III-E-4

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

__Assumptions:__

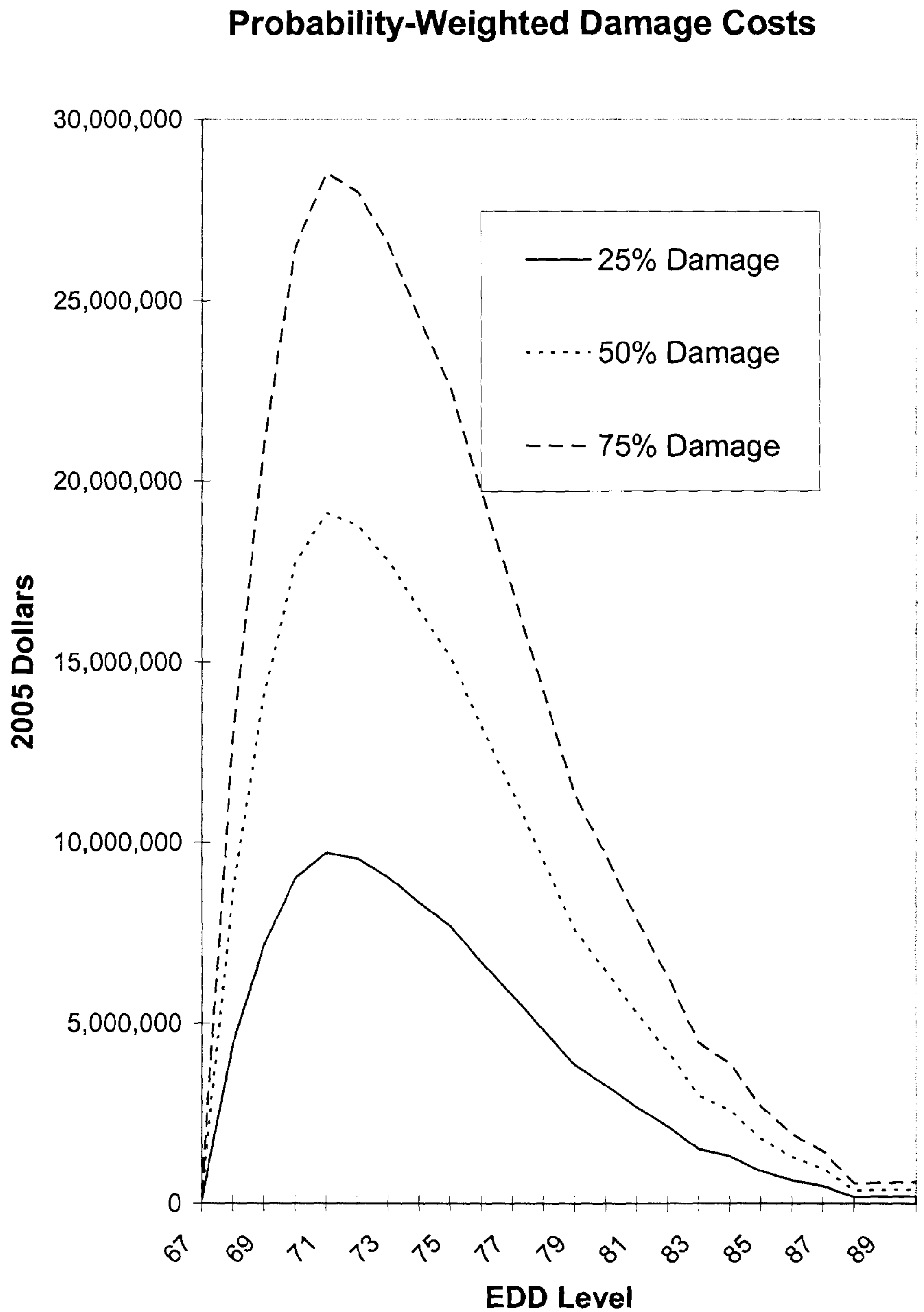
Mean Peak Day =	**67.0 EDD**	
Std Dev Peak Day =	**6.0 EDD**	
Heating Increment =	**1,463 MMBtu/EDD**	
No. of Firm Customers =	**80,303**	
GDP Deflator (1991-2005) =	**1.35**	

	1991 dollars	2005 dollars
Relight Costs =		**$80.01 /customer**
Freeze-Up Damages =	**$33,000.00 /customer**	**$44,631.19 /customer**
Total =		**$44,711.20 /customer**

Year-End 2005:	
Comm/Ind Customers	**9,640**
Total Customers	**80,303**
Percent C&I of Total	**12.0%**
Cost of Interruption/Day =	**$27,039,948**

EDD Level	Probability Of Exceeding (1-p)	Equivalent Number of Customers	Residential Customers	Comm/Ind Customers	Cost Of Interruption to Comm/Ind Customers	Probability-Weighted Cost Of Damages Given X% of Residential Customers With Damages PLUS Cost of Interruption to Comm/Ind Customers (2005 dollars) 25%	50%	75%
67.0	0.4293	19	17	2	$6,457	83,754	164,736	245,718
68.0	0.3627	1,200	1,056	144	$404,009	4,426,492	8,706,463	12,986,435
69.0	0.3010	2,346	2,065	282	$790,037	7,184,146	14,130,491	21,076,837
70.0	0.2563	3,460	3,045	415	$1,165,035	9,022,058	17,745,478	26,468,899
71.0	0.2103	4,542	3,997	545	$1,529,471	9,718,756	19,115,814	28,512,871
72.0	0.1677	5,594	4,923	672	$1,883,783	9,541,991	18,768,134	27,994,277
73.0	0.1343	6,618	5,823	794	$2,228,388	9,043,488	17,787,630	26,531,772
74.0	0.1077	7,614	6,700	914	$2,563,679	8,338,854	16,401,685	24,464,516
75.0	0.0880	8,583	7,552	1,030	$2,890,030	7,683,274	15,112,226	22,541,178
76.0	0.0690	9,526	8,383	1,144	$3,207,792	6,686,774	13,152,210	19,617,646
77.0	0.0543	10,446	9,192	1,254	$3,517,300	5,773,473	11,355,840	16,938,207
78.0	0.0417	11,341	9,980	1,361	$3,818,873	4,807,124	9,455,128	14,103,132
79.0	0.0310	12,214	10,748	1,466	$4,112,810	3,851,782	7,576,068	11,300,353
80.0	0.0247	13,065	11,497	1,568	$4,399,399	3,278,425	6,448,331	9,618,238
81.0	0.0190	13,895	12,227	1,668	$4,678,912	2,685,715	5,282,530	7,879,346
82.0	0.0143	14,705	12,940	1,765	$4,951,608	2,144,148	4,217,324	6,290,499
83.0	0.0097	15,496	13,635	1,860	$5,217,733	1,523,772	2,997,106	4,470,439
84.0	0.0080	16,267	14,314	1,953	$5,477,521	1,323,840	2,603,859	3,883,879
85.0	0.0053	17,020	14,977	2,043	$5,731,196	923,433	1,816,300	2,709,166
86.0	0.0037	17,756	15,625	2,132	$5,978,973	662,307	1,302,691	1,943,075
87.0	0.0027	18,475	16,257	2,218	$6,221,053	501,180	985,771	1,470,362
88.0	0.0010	19,178	16,876	2,302	$6,457,631	195,090	383,722	572,354
89.0	0.0010	19,865	17,480	2,385	$6,688,893	202,076	397,464	592,851
90.0	0.0010	20,536	18,071	2,465	$6,915,016	208,908	410,901	612,893

(Probability of Exceeding TIMES
[Comm/Ind Cost of Interruption PLUS
No. Of Residential Customers TIMES Percent TIMES
Total Damage Costs])


Probability-Weighted Damage Costs
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2005 Dollars
25% Damage
50% Damage
75% Damage
67
69
71
73
75
77
79
81
83
85
87
89
EDD Level

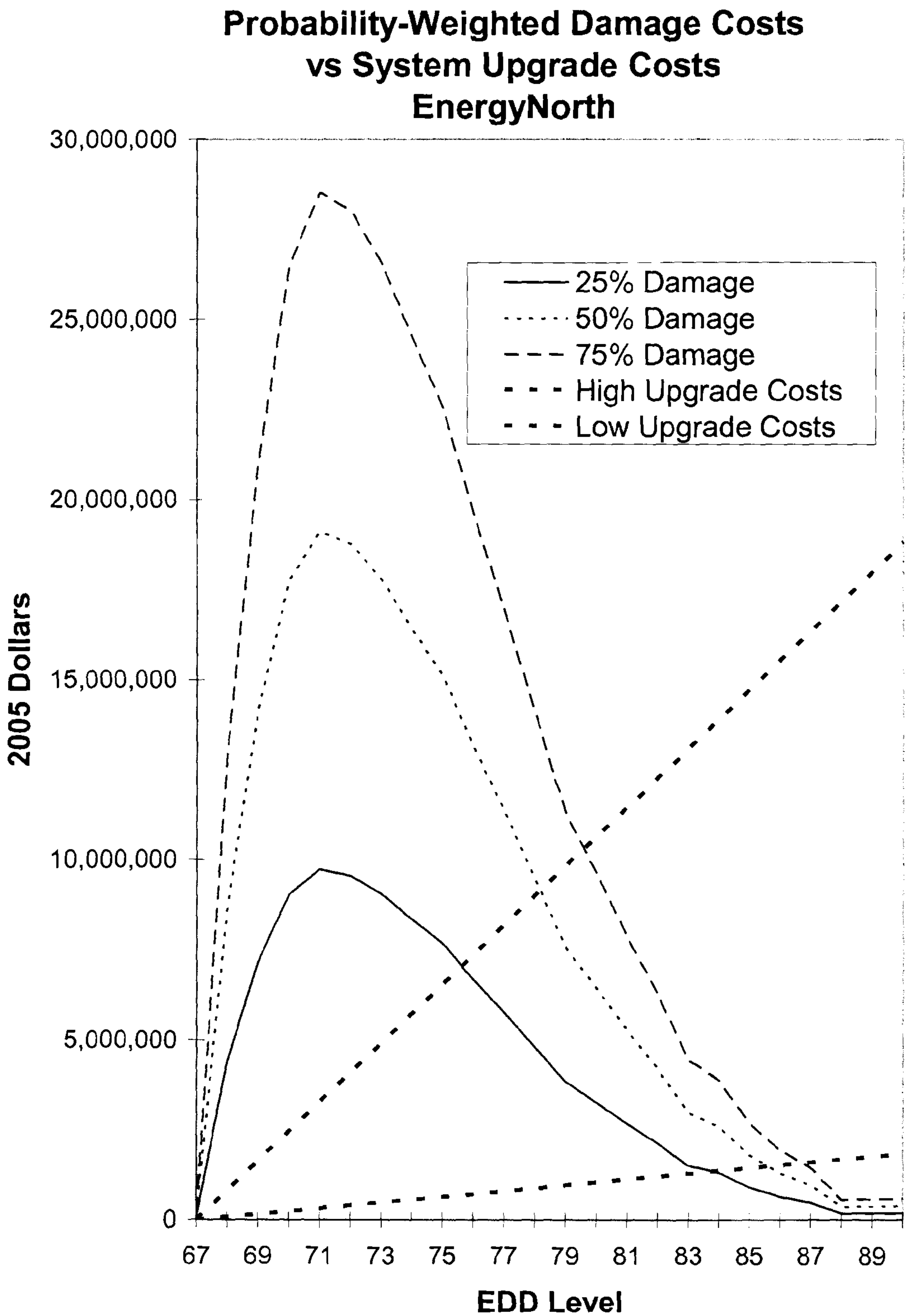
EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Peak Day =	67.0 EDD	
Std Dev Peak Day =	6.0 EDD	
GDP Deflator (1994-2005) =	1.26	
	1994 dollars	**2005 dollars**
Cost of Add'l Propane Capacity =	$43.86 /MMBtu	$55.40 /MMBtu
Cost of New Pipeline Capacity =	/MMBtu	$558.52 /MMBtu

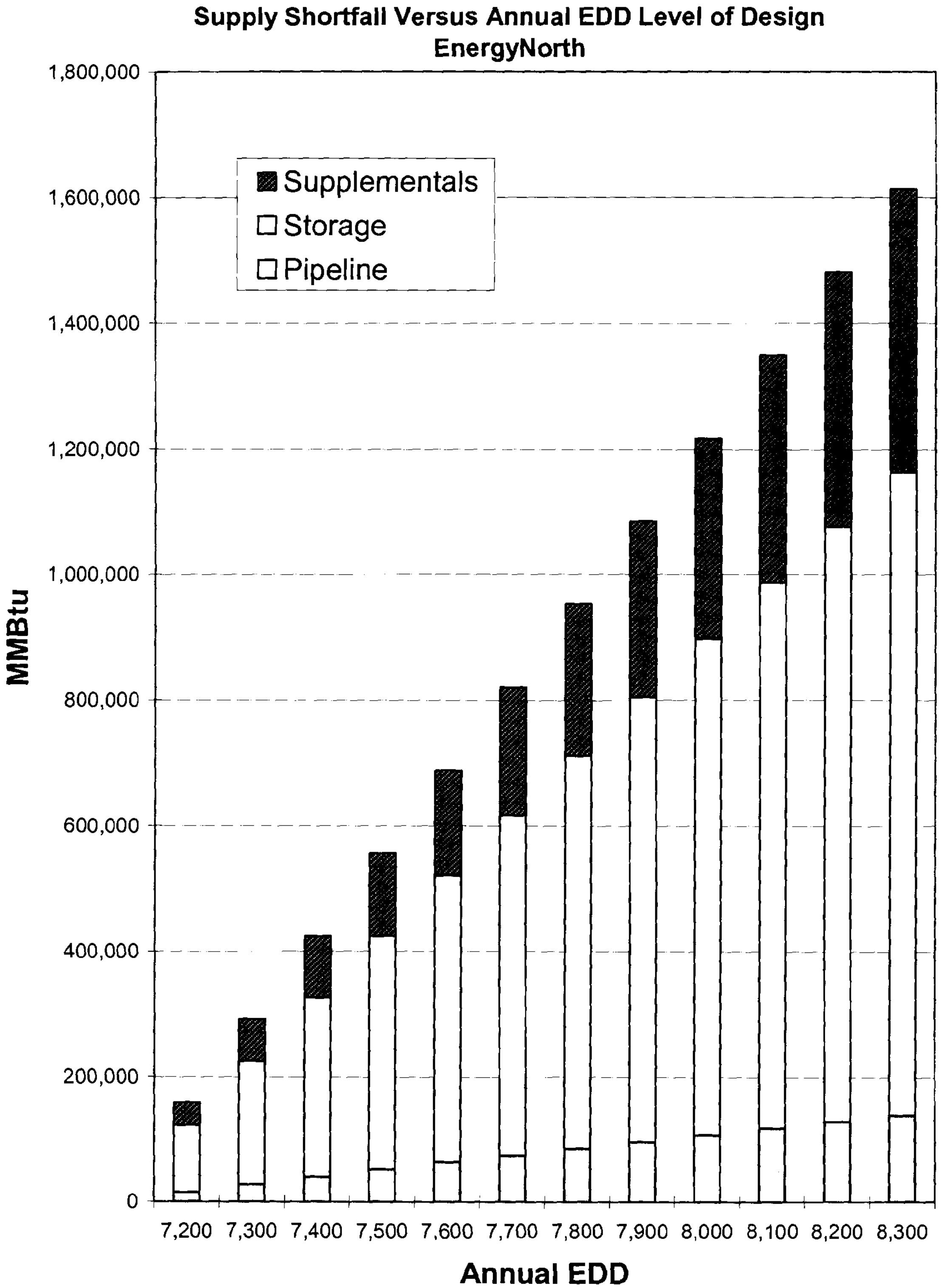
		Low Upgrade Costs Case	High Upgrade Costs Case
EDD Level	Delta Supply (MMBtu)	Propane Capacity Costs	Pipeline Capacity Costs
67.0	23	$1,297	$13,076
68.0	1,467	$82,357	$830,358
69.0	2,950	$163,417	$1,647,639
70.0	4,413	$244,477	$2,464,920
71.0	5,877	$325,537	$3,282,201
72.0	7,340	$406,596	$4,099,483
73.0	8,803	$487,656	$4,916,764
74.0	10,266	$568,716	$5,734,045
75.0	11,730	$649,776	$6,551,326
76.0	13,193	$730,836	$7,368,608
77.0	14,656	$811,896	$8,185,889
78.0	16,120	$892,956	$9,003,170
79.0	17,583	$974,016	$9,820,451
80.0	19,046	$1,055,076	$10,637,732
81.0	20,509	$1,136,136	$11,455,014
82.0	21,973	$1,217,196	$12,272,295
83.0	23,436	$1,298,255	$13,089,576
84.0	24,899	$1,379,315	$13,906,857
85.0	26,363	$1,460,375	$14,724,139
86.0	27,826	$1,541,435	$15,541,420
87.0	29,289	$1,622,495	$16,358,701
88.0	30,753	$1,703,555	$17,175,982
89.0	32,216	$1,784,615	$17,993,264
90.0	33,679	$1,865,675	$18,810,545

Chart III-E-7



Probability-Weighted Damage Costs
vs System Upgrade Costs
EnergyNorth
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2005 Dollars
67
69
71
73
75
77
79
81
83
85
87
89
EDD Level
25% Damage
50% Damage
75% Damage
High Upgrade Costs
Low Upgrade Costs

Chart III-E-8



Supply Shortfall Versus Annual EDD Level of Design
EnergyNorth
Supplementals
Storage
Pipeline
MMBtu
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
7,200
7,300
7,400
7,500
7,600
7,700
7,800
7,900
8,000
8,100
8,200
8,300
Annual EDD

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Pipeline Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	2,745	15,696	28,357	40,341	52,180	63,896	75,163	86,174	97,185	108,196	119,207	129,989	140,221
Total	0	2,745	15,696	28,357	40,341	52,180	63,896	75,163	86,174	97,185	108,196	119,207	129,989	140,221

Storage Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	35,911	108,441	179,254	249,827	319,477	388,415	455,501	519,663	583,343	645,956
Apr	0	0	30,687	114,890	163,132	171,303	179,568	188,008	196,447	204,886	213,325	221,765	230,204	238,643
May	0	0	0	144	423	703	983	1,269	1,812	2,355	2,898	3,441	4,129	5,202
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	18,834	77,102	81,888	87,037	92,232	97,427	102,622	107,817	113,011	118,206	123,401	128,596	133,791
Total	0	18,834	107,789	196,922	286,503	372,679	457,232	541,725	625,552	708,667	789,930	868,269	946,271	1,023,592

Supplementals Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	13,375	35,735	58,601	82,391	106,528	131,727	159,248	187,010	215,461
Feb	0	411	28,579	56,861	85,371	104,056	115,503	126,951	138,399	150,210	162,557	174,903	187,250	199,596
Mar	0	5,762	7,833	9,904	11,976	14,047	16,118	18,190	20,261	22,332	24,660	27,589	30,842	34,639
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	6,172	36,412	66,765	97,347	131,478	167,356	203,742	241,050	279,071	318,944	361,740	405,103	449,697

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Annual EDD =	7,079 EDD
Std Dev Annual EDD =	291.29 EDD
Heating Increment =	1,463 MMBtu/EDD
No. of Firm Customers =	80,303

	Cumulative Probability Of Occurrence	Probability Of Exceeding	Frequency of Occurrence		Delta Supply (MMBtu)			
EDD Level	(p)	(1-p)	1/(1-p) (years)	EDD Excess	Pipeline	Storage	Supplementals	Total
7,100		0.4670	2.14	21.0	2,745	18,834	6,172	27,751
7,200		0.3297	3.03	121.0	15,696	107,789	36,412	159,897
7,300		0.2167	4.62	221.0	28,357	196,922	66,765	292,044
7,400		0.1320	7.58	321.0	40,341	286,503	97,347	424,190
7,500		0.0733	13.64	421.0	52,180	372,679	131,478	556,337
7,600		0.0377	26.55	521.0	63,896	457,232	167,356	688,483
7,700		0.0170	58.82	621.0	75,163	541,725	203,742	820,630
7,800		0.0050	200.00	721.0	86,174	625,552	241,050	952,777
7,900		0.0017	600.00	821.0	97,185	708,667	279,071	1,084,923
8,000		0.0010	1000.00	921.0	108,196	789,930	318,944	1,217,070
8,100		0.0000	100000.00	1,021.0	119,207	868,269	361,740	1,349,216
8,200		0.0000	100000.00	1,121.0	129,989	946,271	405,103	1,481,363
8,300		0.0000	100000.00	1,221.0	140,221	1,023,592	449,697	1,613,509
7,680		0.0211	47.32					
				(EDD Level MINUS Mean Peak)	(EDD Excess TIMES Heating Increment) (MMBtu)			

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Annual EDD =	7,079.0	
Std Dev Annual EDD =	291.3	
Cost of Interruption/Day =	$27,039,946	
Supply Cost	$7.500	$/MMBtu
Long-Haul Capacity Cost	$583.58	$/MMBtu
Short-Haul Capacity Cost	$70.680	$/MMBtu
Storage D1 Cost	$13.800	$/MMBtu
Storage D2 Cost	$0.222	$/MMBtu

					Costs in 2005 Dollars				Costs in 2005 Dollars	
EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	Days Of Interruption	Cost of 25% Interruption	Prob Wghted Cost	Required Incremental Capacity (MMBtu)	Required Incremental Winter Volume (MMBtu)	Short-Haul Supply Cost	Long-Haul Supply Cost
7,100		0.4670	2.14	1	$7,619,357	$3,558,240	124	25,006	$203,615	$260,199
7,200		0.3297	3.03	6	$42,372,049	$13,968,652	719	144,201	$1,174,221	$1,500,825
7,300		0.2167	4.62	11	$76,929,747	$16,668,112	1,314	263,687	$2,147,194	$2,744,453
7,400		0.1320	7.58	16	$110,152,494	$14,540,129	1,911	383,849	$3,125,527	$3,994,098
7,500		0.0733	13.64	20	$138,479,257	$10,155,146	2,510	504,157	$4,105,105	$5,245,690
7,600		0.0377	26.55	25	$165,855,802	$6,247,235	3,110	624,588	$5,085,818	$6,499,462
7,700		0.0170	58.82	29	$193,409,949	$3,287,969	3,713	745,467	$6,070,185	$7,757,960
7,800		0.0050	200.00	32	$217,335,205	$1,086,676	4,318	866,602	$7,056,657	$9,019,209
7,900		0.0017	600.00	36	$240,357,380	$400,596	4,922	987,738	$8,043,129	$10,280,458
8,000		0.0010	1000.00	39	$261,000,226	$261,000	5,526	1,108,674	$9,029,582	$11,541,581
8,100		0.0000	100000.00	42	$281,139,916	$2,811	6,129	1,230,009	$10,015,876	$12,801,602
8,200		0.0000	100000.00	44	$300,089,449	$3,001	6,728	1,351,374	$11,003,680	$14,061,557
8,300		0.0000	100000.00	47	$318,033,986	$3,160	7,322	1,473,288	$11,995,331	$15,322,887
					Days Of Interruption times Cost of Interruption/Day	Cost of Interruption times Prob. of Exceeding			(Incremental Vol times Supply+D2 Costs) + (Incr Capacity times Short-Haul+ D1 Costs)	(Incremental Vol times Supply Cost) + (Incr Capacity times Long-Haul Cost)

EDD Level	Cost of 75% Interruption	Prob Wghted Cost
7,100	$22,858,072	$10,674,720
7,200	$127,116,148	$41,905,957
7,300	$230,789,240	$50,004,335
7,400	$330,457,481	$43,620,388
7,500	$415,437,772	$30,465,437
7,600	$497,567,406	$18,741,706
7,700	$580,229,848	$9,863,907
7,800	$652,005,616	$3,260,028
7,900	$721,072,140	$1,201,787
8,000	$783,000,677	$783,001
8,100	$843,419,748	$8,434
8,200	$900,268,346	$9,003
8,300	$954,101,957	$9,541

Chart III-E-12