Vermont Gas Systems, Inc.

Integrated Resource Plan
2017

Vermont Gas

July 14, 2017

Judith C. Whitney, Clerk
Vermont Public Utility Commission
120 State Street
Drawer 20
Montpelier, VT 05620-2701

Dear Ms. Whitney:

As required by 30 V.S.A. §218(c), enclosed are an original and 6 copies of Vermont Gas Systems, Inc. Integrated Resource Plan.

Sincerely,

Eileen Simollardes
Vice President - Regulatory Affairs

Enclosure

cc: James Porter, Esq.
Edward McNamara, Department of Public Service
Joanne White, Department of Public Service
David Westman, Vermont Energy Investment Corporation

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SECTION 1: EXECUTIVE SUMMARY

INTRODUCTION

Vermont Gas Systems, Inc. ("VGS", or the "Company") has developed this Integrated Resource Plan ("IRP" or "Plan") as a framework for evaluating long-term resource strategies and plans. The IRP integrates several planning phases, including a demand forecast, supply-side and energy efficiency resource planning and financial planning. The IRP covers the 20-year period from October, 2017 through September, 2037.

The primary planning objective for VGS is to provide safe and reliable energy products and services to Vermont families and businesses at reasonable and affordable prices, and to provide leadership in achieving Vermont's clean energy future. The IRP identifies certain strategies that achieve that objective. Some of the strategies are presently underway, such as bringing the choice and opportunity of natural gas and efficiency services to Addison County and developing renewable natural resources, while others are based on future market developments. In this manner, the IRP describes the framework for future resource decisions.

The Company's IRP is consistent with its strategic planning process as it examines opportunities and risks brought about through structural and competitive changes within the energy industry. As such, VGS creates choices for customers through service expansion and the growth of product and service offerings, while maintaining reasonable and affordable prices. Vermont Gas is confident natural gas will play a key role in Vermont's clean energy future, providing low cost and low carbon energy to Vermont's key economic hubs.

It is important to note that this IRP does not require additional upstream or transmission system capacity prior to filing of the Company's next IRP. Presently, the Company has sufficient upstream and transmission system capacity to meet the demand forecast scenarios presented in this IRP over the next three years.

The Company recognizes that there are several 'clean energy' initiatives to advance a low-carbon future under development that could impact the demand for natural gas in the future. These include: (a) Vermont's goal to achieve 90 percent renewables by 2050; (b) Renewable Energy Standard Tier 3 programs; (c) increasing penetration of cold climate heat pumps; (d) the

City of Burlington's goal to be carbon neutral; and (e) business commitments to the achieve the Paris Climate Accord. However, how these initiatives will manifest and what specific role Vermont Gas will play in helping to achieve them is evolving. As such, the Company has not explicitly reflected such initiatives in this IRP, but will likely be further developed for inclusion in the next IRP. The Company believes that such an approach is reasonable since this IRP does not require additional upstream or transmission system capacity prior to filing of the next IRP.

PLANNING PROCESS

The planning process for this IRP consists of four phases. The first phase is development of relative heating fuel prices. Given the importance of heating fuel prices on the demand for natural gas, the first phase establishes the Company's price advantage over heating oil during the forecast period. Heating oil is the primary focus of the Company's price advantage since 42.6 percent of Vermont's homes are heated with heating oil.[1] In comparison, 17.7 percent of Vermont homes are heated with natural gas and 15.8 percent are heated with propane.

The Company's price advantage over heating oil has been an important driver of customer and sales growth over the past decade. Conversion rates on in-fill customers, for example, have been tied over the past decade to the Company's price advantage over heating oil. For this reason, the Company prepared the following three scenarios that provide a range of relative fuel prices.

- "Base" price advantage – relies on the US Energy Information Administration ("EIA") "Reference Case", which includes a 20-year projection of regional natural gas and heating oil residential prices, adjusted to reflect the relative difference between New England and Vermont residential fuel prices;
- "High" price advantage – assumes Vermont Gas has a more robust competitive position relative to fuel oil and relies on the EIA "High Oil Case", which includes a 20-year

[1] American Community Survey; https://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml

projection of regional natural gas and heating oil residential prices, adjusted to reflect the relative difference between New England and Vermont residential fuel prices; and

- "Low" price advantage – assumes a tightening of Vermont Gas' competitive position relative to fuel oil and relies on the EIA "Low Oil Case", which includes a 20-year projection of regional natural gas and heating oil residential prices, adjusted to reflect the relative difference between New England and Vermont residential fuel prices.

The second planning phase is development of a 20-year demand forecast. The IRP requires an understanding of future demands as it represents an important input into the resource planning process. The demand forecast in this IRP utilizes the same general methodology as in past IRPs, updated for current information. Specifically, the demand forecast utilizes the relative price of natural gas to heating oil along with the projected growth in population and gross state product as a basis for developing the demand forecast. Interruptible customers are evaluated on a customer-by-customer basis.

The range of relative fuel prices generated the following demand forecast scenarios:

- "Base Growth" demand forecast utilizes the Base price advantage projection;
- "High Growth" demand forecast utilizes the High price advantage projection; and
- "Low Growth" demand forecast utilizes the Low price advantage projection.

The demand forecasts also incorporate the impact of the Company's energy efficiency programs.

The third planning phase is development of resource strategies and plans that provide a basis for future resource decisions. The resource plans include:

- Supply plan. Describes the planning process and analysis used to ensure that supply resource decisions balance reliability and reasonable cost objectives. The supply plan is also evaluated to ensure that it meets the Company's objectives of stability and flexibility. The supply plan is built on meeting the demand forecasts discussed above with gas supply, pipeline transportation and storage resources, peaking resources, and pipeline alternatives. The supply plan also includes the introduction of Renewable Natural Gas ("RNG") supply in support of the state's energy goals. The supply plan describes the availability and cost of a number of supply alternatives; and the Company's approach regarding the evaluation of the alternatives within VGS' objectives.

- Energy Efficiency plan. Describes the planning process and analysis that the Company utilizes as an Energy Efficiency Utility. The energy efficiency plan follows the Demand Resource Plan ("DRP"), which is currently in progress for 2018-2020, and establishes budgets and savings goals for those years, as well as, savings and budgets through 2037. The energy efficiency plan reflects the DRP and its anticipated energy efficiency savings applied to each of the three scenarios.

- Transmission and Distribution plan. Describes the planning process and analysis used to ensure that on-system transmission and distribution resources meet reliability, growth and customer service objectives. The operations plan is built on meeting the demand forecasts discussed above with transmission and distribution resources and a series of assumptions concerning pipeline costs and requirements. The operations plan produces projected capital and operating costs for the transmission and distribution system to meet the requirements of the three demand forecasts.

- Financial plan. Describes the financial planning process and analysis used to support the IRP. The financial plan produces important IRP metrics, including the financial and customer implications of various resource decisions.

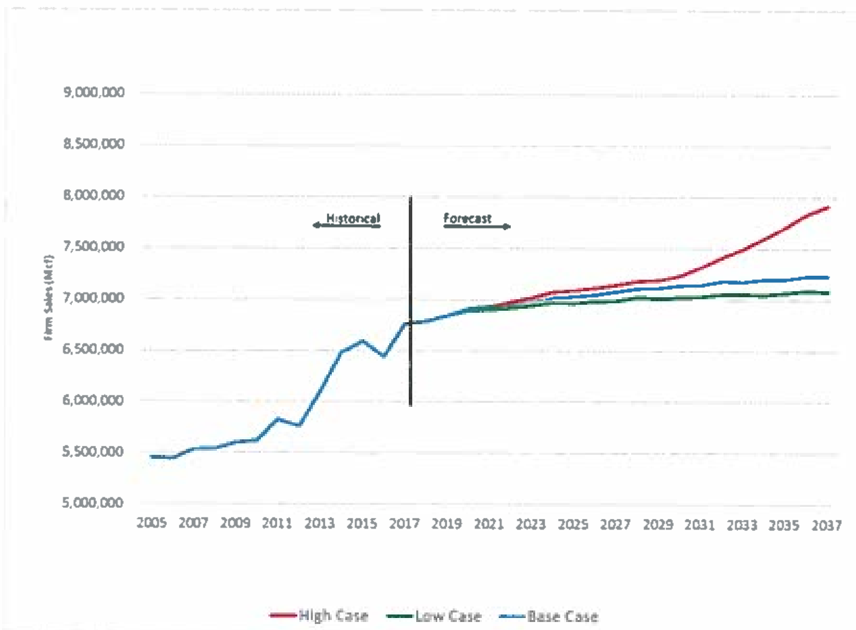
The fourth phase is a description of how the Company plans to implement the IRP, identifying specific short-term steps the Company plans to take over the next several years. As the Plan is dynamic and focused on the critical inputs to VGS' decision-making rather than discrete decisions themselves, longer-term implementation plans are not meaningful and have therefore not been prepared.

RESULTS

A high-level summary of the IRP results are provided below.

Market Growth and Load Forecast: Figure 1.1 illustrates the results of the Company's demand forecast under three different scenarios: base growth, high growth and low growth.

Figure 1.1: Demand Forecast



The cases reflect changes in certain assumptions, including a natural gas price advantage over heating oil. Figure 1.1 shows an average annual increase in the base case of 0.33 percent over the planning period. The increase is largely attributable to population growth as well as a projected price advantage over heating oil. Figure 1.1 also shows an average annual increase in the high growth case of 0.81 percent over the planning period. The high growth case assumes as a "what if" planning scenario with natural gas expansion to Rutland County. Such expansion, while not being pursued at this time, would be evaluated only in response to substantial customer demand resulting from a significant price advantage over heating oil, strong public policy support and resounding local community backing. Such an expansion would, represents a significant impact on the demand forecast as well as resource planning. Figure 1.1 also shows an average annual increase in the low case of 0.22 percent over the planning period. The decrease from the base case is largely attributable to a lower customer demand due to a lower price advantage.

Energy Efficiency: Over the planning horizon Vermont Gas expects to operate as an Energy Efficiency Utility ("EEU") with its budgets and savings goals established through DRP process with the regulatory bodies. The energy efficiency section of this Plan embodies the budgets and savings goals contemplated in the current DRP, which includes aggressive energy efficiency in Addison County.

Supply-Side Plan: The IRP evaluates supply resource requirements to meet the demand forecast discussed above. With the anticipated additional TransCanada Pipeline ("TCPL") capacity scheduled to be available in 2018, the Company has sufficient supply capacity for the next several years to meet demand forecast under all three scenarios; thus, there are no immediate plans to add supply capacity. However, the Company has undertaken over the past several years two initiatives to minimize supply costs while maintaining flexibility and stability. First, the Company has completed transition of its pipeline contracts from long-haul, Western Canada routes to short-haul, Eastern Canada routes. The switch from long-haul to short-haul capacity has resulted in significant savings to customers. Longer-term, the Company plans to evaluate its capacity to meet the needs of the demand forecast. In the past, such capacity expansion has occurred through additions on TCPL; however, there are other options that will be evaluated and considered, including: Liquefied Natural Gas, Propane Air, Energy Efficiency and Compressed Natural Gas. Evaluation and consideration of these options will be conducted as part of the Company's need for additional capacity or as opportunities to modify the capacity current under contracts arise.

Transmission and Distribution Plan: The IRP evaluates transmission capacity requirements to meet the demand forecast discussed above. Presently, the Company has sufficient transmission capacity for at least the next five years to meet the demand forecast under all three scenarios; thus, there are no immediate plans to expand the Company's transmission capacity. Longer-term, the Company plans to expand the capacity of its transmission system as necessary to meet the needs of its customers. In the past, such expansion has occurred through phased 'looping' of the transmission system. While phased looping appears to be the preferred alternative to expand transmission capacity based on economics and reliability, as with its supply portfolio, there are other options that will be evaluated and considered, including: Liquefied Natural Gas, Propane Air, Compressed Natural Gas, and Compression. Evaluation and consideration of these options will be conducted as part of the Company's need for such additional on-system capacity. The Company has identified several initiatives to improve the safety, reliability, and cost-effectiveness of the distribution system, including main reinforcement, gate station improvements, farm tap removals and meter replacements.

Financial Plan: The IRP evaluates the potential financial impact of planned resource decisions during the planning period. The evaluation relies on a financial analysis that is based on a projection of revenues, operating expenses and plant investments for each planning case. The financial analysis shows that under current wholesale fuel forecasts and proposed expansion scenarios, the Company is able to maintain its price advantage over the planning period.

Implementation:

The IRP describes certain actions that the Company plans to take over the next 1 to 3 years. Those actions include:

- Expansion into five new communities in Addison County in accordance with previous commitments;
- Use competitive bids for annual supply acquisition;
- Implement aggressive energy efficiency in Addison County
- Contain costs to maintain affordable and competitive rates
- Expand service offerings to include Renewable Natural Gas (RNG)

SECTION 2: MARKET GROWTH AND LOAD FORECAST

OVERVIEW

The Company's integrated resource plan requires an understanding of long-term customer demands. The 20-year demand forecast presented in this section provides a foundation for the evaluation of resources that follows in later sections.

The Company's demand forecast is based on the historical relationship between market growth and certain economic variables, including heating fuel prices and population. The demand forecast incorporates projected economic variables to forecast customer and sales growth. The forecast in the first five years is based on a more granular approach that reflects the Company's current experience and short-term plans. The forecast also reflects the ongoing Addison County natural gas project.

The demand forecast was modelled as the product of forecasted numbers of customers and forecasted use per customer for each rate class. Forecasted number of customers was based on projected economic variables, while forecasted use per customer was based on historical consumption data and a projection of the Company's savings through their energy efficiency programs.

Figure 2.1: Demand Forecast

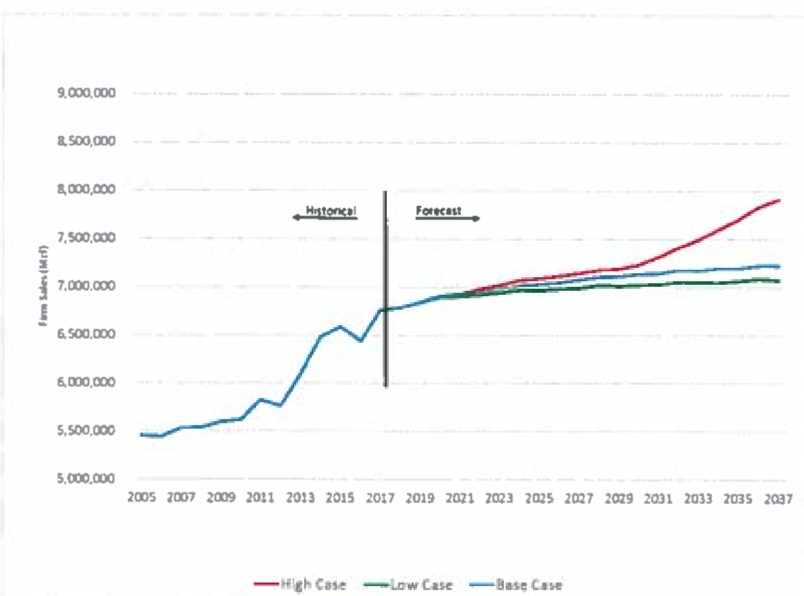


Figure 2.1 illustrates the results of the demand forecast under three different cases: base growth, high growth, and low growth. These cases reflect changes in certain assumptions, including: the assumed natural gas price advantage over heating oil and energy efficiency. The high growth case assumes a significant increase in consumer demand for natural gas modeled as a "what if" planning scenario reflecting natural gas expansion to Rutland County. Such expansion, while not being pursued at this time, would be evaluated only in response to substantial customer demand, strong public policy support, and resounding local community backing. A Rutland County expansion would represent an increase of approximately 10,000 customers, representing a significant impact on the demand forecast as well as the evaluation of resources.

Figure 2.1 shows an average annual increase in the base case of 0.33 percent over the planning period. The increase is largely attributable to a projected price advantage over heating oil. Figure 2.1 also shows an average annual increase in the high growth case of 0.81 percent over the planning period. The increase over the base case is largely attributable to a higher price advantage. Figure 2.1 also shows an average annual increase in the low case of 0.22 percent over the planning period. The decrease over the base case is largely attributable to a lower price advantage.

INTRODUCTION

The 20-year demand forecast presented in this section provides a foundation for the evaluation of resources that follows in later sections. The planning period is 2018 through 2037. The demand forecast is based on the historical relationship between market growth and certain economic variables, including heating fuel prices and population. The demand forecast was modelled as the product of forecasted customers and use per customer for each rate class. To forecast customers by rate class, the forecast relies on projected economic variables. To forecast use per customer, the forecast relies on historical consumption data and a projection of the Company's savings through their energy efficiency programs.

The first step in development of the demand forecast was to identify the historical relationship between the Company's market growth and certain economic variables. This was done by comparing historical customer growth to changes in key economic variables, including heating fuel prices and population. The next step was to forecast customers utilizing forecast economic data from various sources, including the U.S. Energy Information Agency (EIA), Vermont Department of Labor, and the economic forecasting firm Moody's. The customer forecast was adjusted to reflect customer attrition based on historical data.

Forecasted use per customer was based on consumption trends over the past three years, adjusted to reflect the impact of the Company's energy efficiency programs over the planning period. The sales forecast for each rate class is the product of the forecasted customers and use per customer.

As discussed in Section 1.0, the Company prepared alternative demand forecast cases based primarily on changes in the Company's price advantage over heating oil. Specifically, the Company prepared a high growth case based on high customer demand due to a strong price advantage over heating oil of approximately 30 percent, and a low growth case based on low customer demand due to only a 6 percent advantage over heating oil. The "base" case assumes a price advantage of 20 percent.

MARKET SEGMENTS

This section describes the Company's customer classes as well as the key drivers of historical customer growth.

Historical Perspective

There are five market segments that comprise customer growth. Figure 2.2 describes each of the market segments along with its share of customer growth over the past 15 years.

Figure 2.2: New Customer Market Segments

New Customer Market Segment	Description	Percent of 2001-2016 Customer Growth	Key Drivers for Historical Growth
Residential New Construction	New housing units.	23%	Population increase; growth in construction market
Residential Infill	Existing housing unit located on existing distribution main; required only a service line to initiate natural gas service.	41%	Market opportunities; customer demand due to a strong price advantage over heating oil
Residential Main Extension	Existing housing unit not located on existing distribution main; required a main and service line to initiate natural gas service.	26%	Market opportunities; customer demand due to a strong price advantage over heating oil
Commercial & Industrial (C&I)	New and existing C&I units	10%	Growth in Vermont Gross Domestic Product (GDP)
Non-Core	Interruptible customers	<1%	Case-by-case
Total		**100%**	

Figure 2.2 shows that customer growth resulting from residential in-fills and main extensions represented 67.0 percent of total customer growth over the past 15 years. The key drivers of this growth were significant market opportunities and a strong customer demand due to a high price advantage over heating oil. Customer growth from main extensions included expanding service into five new communities over a seven-year period, including: Jericho (2007), Underhill (2008), Hinesburg (2009), Richmond (2012), and Enosburg (2013).

Figure 2.2 also shows that customer growth from residential new construction represented 23.0 percent of total customer growth, and C&I represented 10.0 percent of total customer growth. The key driver for residential new construction was the increase in the population within the service area, particularly in Chittenden County. Non-core or interruptible customers represented less than 1 percent of customer growth.

Sales growth associated with residential and C&I customer growth over the 2001-2016 period was approximately 3.2 Bcf, while sales growth associated with the non-core, interruptible customer growth was approximately 2.0 Bcf. The interruptible market includes a developer of a Compressed Natural Gas ("CNG") facility, which over the past three years has become the Company's largest customer with annual sales approaching 2.5 Bcf, or approximately 20 percent of total sales.

Rate Classes

New customers are placed into one of the Company's rate classes based on their service levels. Below is brief explanation of the service levels and applicable rate classes.

Firm Service. Firm service customers receive an uninterrupted supply of natural gas throughout the year. Firm service is provided under the following tariffs based on the type of customer and usage profile.

Rate R: Residential customers.

Rate G1: Non-residential customers using less than 6,000 ccf per year whose winter

	usage represents more than 70% of the customer's annual usage.
Rate G2:	Non-residential customers using less than 6,000 ccf per year whose winter usage represents less than 70% of the customer's annual usage.
Rate G3:	Non-residential customers using more than 6,000 ccf per year whose winter usage represents more than 70% of the customer's annual usage.
Rate G4:	Non-residential customers using more than 6,000 ccf per year whose winter usage represents less than 70% of the customer's annual usage.

The rates applicable to these rate classes are subject to review and approval by the Vermont Public Utility Commission ("PUC").

Interruptible Service. Interruptible service customers receive natural gas service at rates that are lower than firm service customers in recognition of their ability and obligation to curtail natural gas use during times of peak demand by switching to an alternate fuel. The savings associated with such curtailments are shared with the interruptible customers in the form of lower rates. Since the Company does not serve interruptible customers on its peak day, interruptible sales are not included in the Company's estimate of peak demand.

Interruptible service requirements were determined on a customer by customer basis using historical and projected data. Interruptible sales are derived by taking the total thermal requirements and subtracting an estimate of use during curtailments. The number and length of curtailments in any given year is a function of available supply and pipeline capacity after all firm requirements are met.

Transportation Service. Transportation service customers purchase their gas supply from a third-party supplier rather than Vermont Gas. These customers utilize Vermont Gas for the transportation and distribution of natural gas from the upstream pipeline system to their facility. Presently, there are no transportation service customers and, based on discussions with its largest and most likely customers to elect transportation service, the Company does not anticipate any transportation service customers during the planning period.

FORECAST METHODOLOGY

This section describes the methodology use to develop the demand forecast.

Customer Forecast Methodology

The customer forecast was based on the historical relationship between customer growth and certain economic variables described below:

- Heating fuel prices. The price of natural gas relative to other heating fuels (including heating oil and propane) has been a significant driver of natural gas demand in the past. While fuel choice is based on a number of considerations, including equipment cost, efficiency rating, and operating and maintenance expense, price is the primary driver.[1] That is, customers have been more likely to choose natural gas as its relative price decreases. In addition, customers have been more likely to switch fuels at the end of the useful life of their heating equipment. For customers to convert their heating equipment prior to the end of its useful life requires a strong price advantage to overcome conversion cost and provide for a reasonable return on investment.
- Population. Population has been a major driver of natural gas demand in the past. Population increases in those areas served by natural gas has led to a higher demand for natural gas service due to an increase in housing units that contain natural gas appliances. Natural gas is the preferred fuel for local builders and developers within the Company's service territory, even though there is new emerging technology for heating equipment being offered.
- State economic activity. Increases in state economic activity, as measured by State Gross Domestic Product (GDP) has led to an increase in natural gas demand in the past through an increase in natural gas service to businesses.

The customer forecast was derived based on the historical relationship between customer growth and the three economic variables discussed above. The Company then applied a forecast of economic data to the historical relationship to derive the customer forecast. The forecast of economic data consisted of three cases: (a) base growth, which utilizes baseline economic data that included a price advantage over heating oil that averages 20% over the planning period; (b) high growth, which utilizes robust economic data that included a price advantage over heating oil that averages 30% over the planning period; and (c) low growth, which utilizes less robust economic data that included a price advantage over heating oil that averages 6% over the planning period. Appendix A describes the customer forecast methodology for each market segment and the key assumptions that were used in the base, high, and low growth alternatives.

Expansion South. The Company's demand forecast includes customer growth related to the ongoing Addison County natural gas project. In addition, the high growth case assumes as a "what if" planning scenario reflecting expansion to Vermont communities further south. Such expansion, while not actively being pursued at this time, would be evaluated only in response to substantial customer demand resulting from a significant price advantage over heating oil and strong public policy and community support.

The Addison County natural gas project is presently underway and includes service expansion into eight communities over a three-year period that began in 2017. The planned service commencement dates and communities served by the project are listed below.

2017 Middlebury and Vergennes
2018 Bristol, New Haven, and Monkton
2019 East Middlebury, St. George, and underserved parts of Hinesburg

Since the project is underway, the high and low growth cases are assumed to have the same service commencement dates as under the base growth case. The customer and sales forecasts, however, vary in the base, high, and low growth cases due to the difference in the assumed price advantage and its impact on customer conversion rates.

1 Based on the results of several research studies prepared by the Company.

The Rutland County "what if" planning scenario includes service expansion into four communities over an eight-year period beginning in 2030 in the high growth case only. The communities served under this "what if" planning scenario include: Rutland, Brandon, Pittsford, and Proctor.

Use per Customer Forecast Methodology

The model forecasts use per customer by rate class based on a calculation of base usage, heat usage, and degree days[2]. Base usage is defined as consumption that does not vary with degree days; heat usage is defined as consumption that does vary with degree days since it represents the weather-sensitive portion of usage. Both base usage and heat usage were calculated based on three-year historical averages, whereas degree days are based on 10 years of normalized weather data. Using recent historical averages captures the impact of energy efficiency measures installed to date. The forecast also includes the impact of expected levels of Energy Efficiency Savings.

MARKET GROWTH

The following section details the forecasted customer growth across the Company's existing and future service territories in the base, low growth, and high growth scenarios. The model further forecasts growth by market segment and customer class.

Base Growth

Figure 2.3 provides a breakdown of customer growth by sector and by service area.

2 For a fuller definition of degree days and how they are utilized in the model, refer to the "Design Day" section, below.

Figure 2.3: Breakdown of Customer Growth

Customer Growth	Chittenden/ Franklin	Addison	Total	%
Residential	9,409	2,501	11,910	80%
C&I	2,671	341	3,012	20%
Interruptible	0	0	0	0%
Total	12,080	2,843	14,922	
%	81%	19%	100%	

Figure 2.3 shows that 80 percent of new customers are residential and 20 percent are C&I. The Figure also shows that 81 percent are located in Chittenden and Franklin County and 19 percent from Addison County (as part of the Addison County project).

Breakdown of Residential Customer Growth

Figure 2.4 provides a breakdown of the residential customer growth by market segment.

Figure 2.4: Breakdown of Residential Customer Growth

Residential Customer Segment	Chittenden/ Franklin	Addison	Total	%
New Construction	4,774	0	4,774	40%
In-Fills	4,186	1,937	6,123	51%
Main Extension	449	564	1,013	9%
Total	9,409	2,501	11,910	
%	79%	21%	100%	

Figure 2.4 shows that 51 percent of residential customer growth consists of in-fill customers, while new construction and main extension customers represent 40 and 9 percent, respectively. Figure 2.4 also shows that 79 percent of the residential customer growth will be

located in Chittenden and Franklin County, while Addison County represents 21 percent.

Breakdown of C&I Customer Growth

Figure 2.5 provides a breakdown of C&I customer growth by market segment.

Figure 2.5: Breakdown of C&I Customer Growth

C&I Market Segments	Chittenden/ Franklin	Addison	Total	%
G-1, Small LLF	1,870	239	2,108	70%
G-2, Small, HLF	401	51	452	15%
G-3, Large LLF	267	34	301	10%
G-4, Large HLF	134	17	151	5%
Interruptible	0	0	0	0%
Total	2,671	341	3,012	
%	89%	11%	100%	

Figure 2.5 shows that 70 percent of C&I customer growth will consist of G-1, Small LLF customers; while G-2, G-3 and G-4 customer growth represents 15, 10, and 5 percent of C&I customer growth, respectively. Figure 2.5 also shows that 89 percent of the C&I customer growth will be located in Chittenden and Franklin County, while Addison represents 11 percent.

High Growth

Figure 2.6 provides a comparison of high and base customer growth.

Figure 2.6: High vs. Base Customer Growth

Customer Growth	High Growth	Base Growth	Diff	Diff %
Residential	19,168	11,910	7,258	61%
C&I	3,389	3,012	377	13%
Interruptible	4	1	3	300%
Total	22,561	14,923	7,638	51%

Figure 2.6 shows that residential customer growth is higher under the high growth case as compared to the base growth case by 7,258 customers, or 61 percent. Figure 2.6 also shows that C&I customer growth is higher under the high growth case as compared to the base growth case by 377 customers, or 13 percent. In the high growth case, the Company is assumed to experience stronger customer demand due to a price advantage over heating oil as well as a higher increase in population, increasing the number of residential new construction customers. The high growth case also assumes that natural gas will be available in Rutland County in 2030 but only in response to substantial customer demand resulting from a significant price advantage over heating oil and strong public policy support.

Low Growth

Figure 2.7 provides a comparison of low and base customer growth.

Figure 2.7: Low Market Growth

Customer Growth	Low Growth	Base Growth	Diff	Diff %
Residential	10,434	11,910	-1,476	-12%
C&I	2,952	3,012	-60	-2%
Interruptible	1	1	0	0%
Total	13,387	14,923	-1,536	-10%

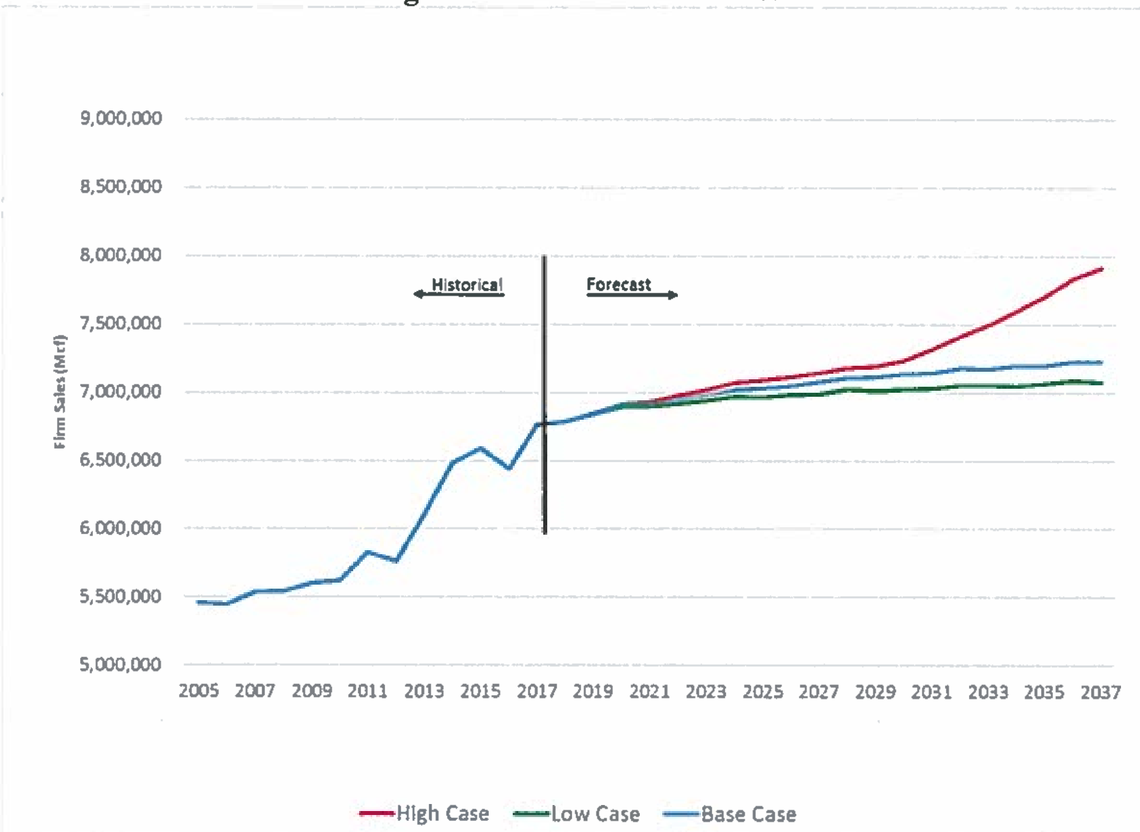
Figure 2.7 shows that residential customer growth is lower under the low growth case as compared to the base growth case by 1,476 customers, or 12 percent. Figure 2.7 also shows that C&I customer growth under the low growth case as compared to the base growth case is lower by 60 customers, or 2 percent. In the low growth case, the Company is assumed to experience a slight price advantage over heating oil as well as a lower increase in population, lowering the number of residential new construction customers.

FORECAST RESULTS

This section details the results of Vermont Gas's demand, customer, and use per customer forecasts. Each forecast includes results related to the base, low growth, and high growth scenarios. While all three cases result in a wide spectrum of sales, customer count, and use per customer, respectively, none appear to fundamentally alter current trends.

Figure 2.8 illustrates the results of the demand forecast.

Figure 2.8: Demand Forecast

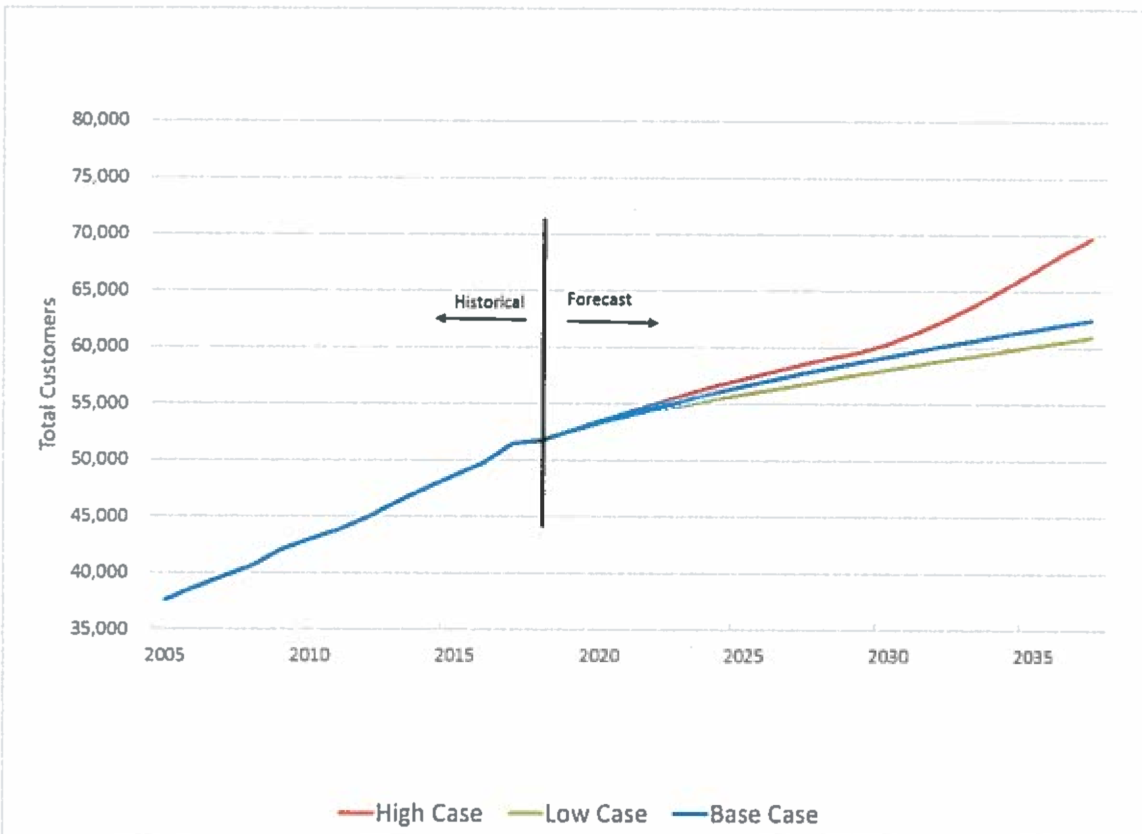


As shown in Figure 2.8, the base growth forecast results in an average annual increase of 0.33 percent over the planning period. The increase is largely attributable to higher customer demand due to a strong price advantage over heating oil (20 percent). Figure 2.8 also illustrates a high growth forecast that results in an average annual increase of 0.81 percent. The higher growth rate is largely attributable to a more substantial customer demand due to a stronger price advantage (30 percent) and population growth than under the base growth forecast. Figure 2.8 also illustrates a low growth forecast that results in an average annual increase of 0.22 percent.

The lower growth rate is largely attributable to lower customer demand due to a smaller price advantage (6 percent) over heating oil and population growth than under the base growth forecast.

The demand forecast is based on a customer forecast and use per customer forecast. The results of the customer forecast are presented in Figure 2.9.

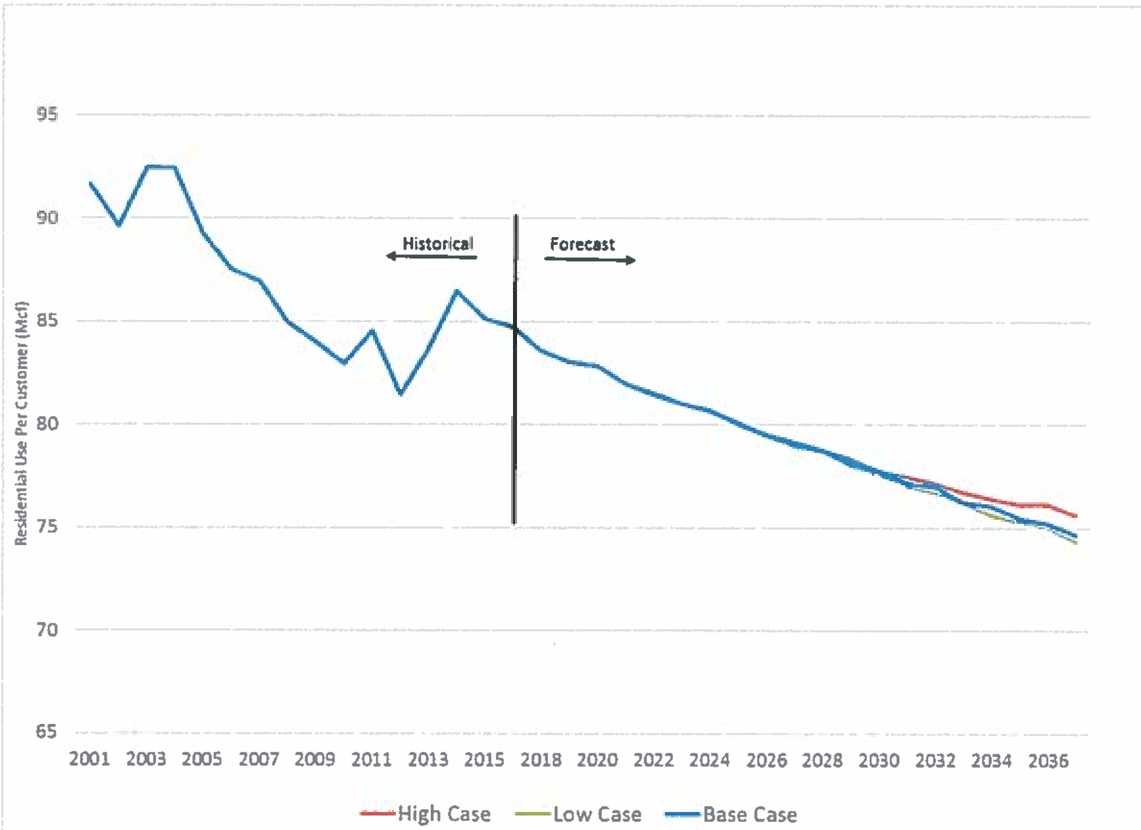
Figure 2.9: Customer Forecast



As shown in Figure 2.9, the base growth customer forecast results in an average annual increase of 0.97 percent over the planning period. The increase is largely attributable to strong customer demand due to the price advantage over heating oil (20 percent). Figure 2.9 also illustrates a high growth forecast that results in an average annual increase of 1.53 percent. The higher growth rate is largely attributable to stronger customer demand due to the price advantage (30 percent) and population growth than under the base growth forecast. Figure 2.9 also illustrates a low growth forecast that results in an average annual increase of 0.85 percent. The lower growth rate is largely attributable to lower customer demand due to a smaller price advantage (6 percent) and population growth than under the base growth forecast.

Figure 2.10 illustrates the results of the use per customer forecast.

Figure 2.10: Residential Use per Customer Forecast



The base growth forecast results in an average annual decrease in use per customer of 0.6 percent over the planning period. The decrease is largely attributable to the impact of the Company's energy efficiency programs as well as the improvement in heating equipment efficiency and thermal building performance. Figure 2.10 also illustrates a high growth forecast that results in an average annual decrease of 0.5 percent. Figure 2.10 also illustrates a low growth forecast that results in an average annual decrease of 0.6 percent. The historical period from 2001 through 2016 reflects an average annual decrease of 0.5 percent.

DESIGN DAY

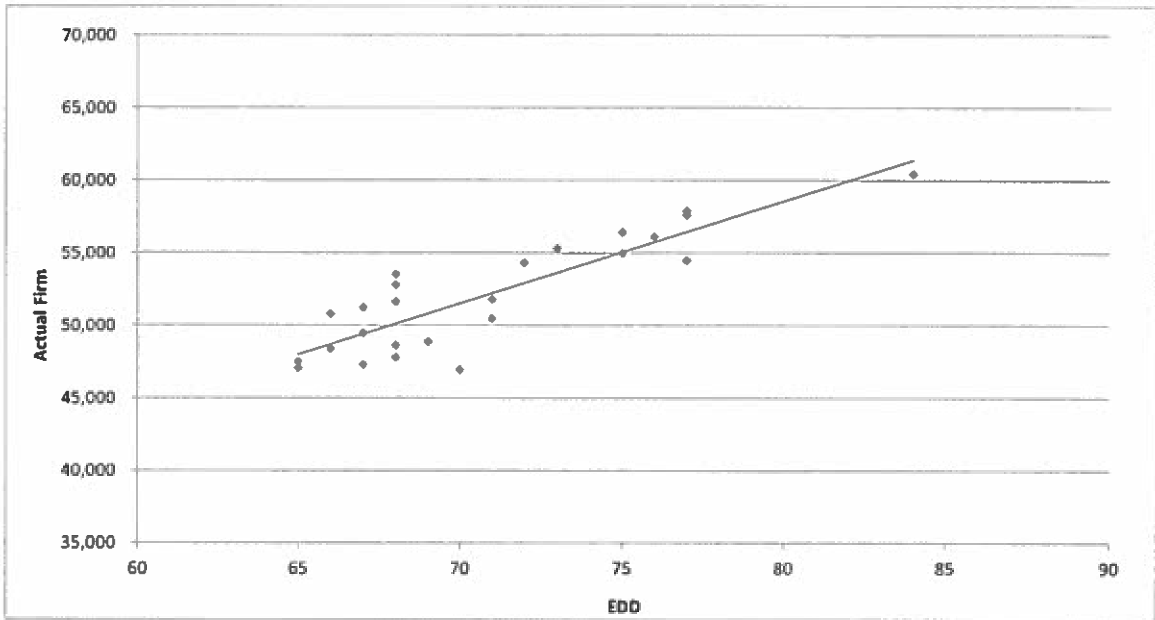
This section defines Heating Degree Days and describes Vermont Gas's use of them in the demand forecast.

Historical Perspective

Design day, as used by Vermont Gas for planning purposes, is the total system requirements at 86 Heating Degree Days ("HDDs"), or 93 Effective Degree Days ("EDDs"). Vermont Gas uses a design day criteria of the actual coldest day experienced within the last 30 years: January 26, 1994. Vermont Gas utilizes this 30-year methodology for design day weather to add conservatism to its planning because (a) its firm load is highly weather-dependent, as apparent by a needle peak (persistent level of peak demand) usage profile during colder weather and (b) Vermont Gas has only one interconnect with TransCanada Pipeline System ("TCPL Mainline") and is at the end of the TCPL Mainline. This approach is consistent with the approach taken in past IRPs and other planning initiatives.

Figure 2.11 provides the historical peak days from two perspectives: actual system peak and firm load peak day.

Figure 2.11: Historical Peak Day



Design Day Methodology

For forecasting design-day, Vermont Gas employed a multi-step methodology. First, as described above, Vermont Gas' design day is assumed to be a 73 HDD day, followed by an 86 HDD / 93 EDD day. Based on this design day, the first step in the process was to run a regression analysis using data from all days in the past five years where the HDDs exceeded 65. The output of the regression analysis then becomes the starting point for forecasting the design-day. Since design-day is such a critical calculation, Vermont Gas had its calculation methodology reviewed by an outside party. The subsequent evaluation recommended that Vermont Gas forecast a band of possible design-day loads. To adjust the regression analysis for a high and low band, Vermont Gas reviewed the 10 coldest two day periods over the past three years and calculated the firm heating use per effective degree day. The variance from the minimum to the maximum use per effective degree day is then applied to the regression analysis to determine the high and low ends of the design-day forecast band. The band represents simulated confidence intervals or Z-scores but utilize actual data rather than statistical benchmarks.

The design-day forecast as calculated from the regression analysis is then compared to the design-day forecast using January 2017 customer sales statistics in order to spread the regression output among rate classes. For each rate class, the base use per customer and the heating use per degree day were calculated based on January 2017 sales. Using this data, the assumed firm load at an 86 HDD was then calculated (referenced as the "sales statistics design-day") and compared to the results of the regression analysis.

The customer sales data is a monthly average, and therefore the use per degree day reflects the average usage over the course of the month; therefore, the effect of warmer days may mask the impact of usage on a cold day. Consequently, the sales statistics design-day calculation will yield a result that is consistently *lower* than even the low band of the regression design day calculation. While the sales statistics design-day is not ideal, it is the only data available to determine design-day impact by rate class. Therefore, a ratio of the sales statistics design-day to the regression design-day results (average, high, and low) is determined. The sales statistics, by rate class, are then applied to forecasted number of customers to determine the forecasted sales statistics design-day, which is then adjusted by the regression ratios to determine the design-day forecast.

The results of this multi-step process - regression, usage bands, sales statistics, and ratios is shown in Figure 2.12, the data of which is included in Figure 2.13.

Figure 2.12: Forecast Design Day

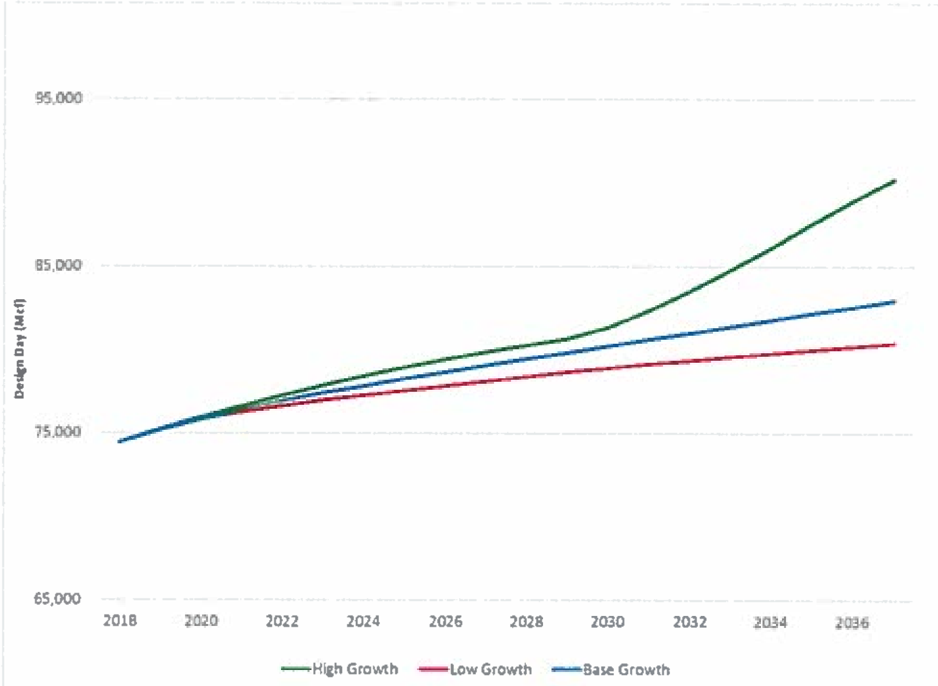


Figure 2.13: Table of Forecast Design Day

Year	DD Base Growth	DD High Growth	DD Low Growth
2017-18	74,467	74,467	74,467
2018-19	75,228	75,250	75,194
2019-20	75,913	75,996	75,813
2020-21	76,425	76,625	76,244
2021-22	76,929	77,261	76,639
2022-23	77,407	77,876	76,977
2023-24	77,846	78,440	77,274
2024-25	78,264	78,959	77,553
2025-26	78,671	79,432	77,826
2026-27	79,062	79,867	78,103
2026-28	79,452	80,277	78,391
2026-29	79,843	80,664	78,650
2026-30	80,233	81,338	78,894
2026-31	80,624	82,370	79,132
2026-32	81,014	83,523	79,359
2026-33	81,405	84,802	79,582
2026-34	81,795	86,110	79,798
2026-35	82,185	87,555	80,009
2026-36	82,576	88,925	80,212
2026-37	82,966	90,207	80,406

ADDITIONAL MARKETS

Vermont Gas has identified several additional markets that may impact future growth. These markets are distinguished from the earlier discussion since they include: (a) non-traditional delivery service, such as bulk compression and delivery of Compressed Natural Gas ("CNG") and Gas Islands; and (b) non-traditional technologies, such as electric generation, heat pumps, and natural gas vehicles.

Compressed Natural Gas (CNG)

The CNG market represents sales to CNG developers who compress and deliver natural gas to large businesses in specially designed trailers. The technology provides the benefits of providing natural gas service to those who do not have access to a natural gas pipeline. CNG also provides end users an opportunity to convert to natural gas before a pipeline is extended to their facility.

Presently, Vermont Gas serves one CNG developer with estimated sales approaching 2.5 Bcf, making the developer its largest customer. All of the sales are provided under the interruptible service CNG tariff; thus, these CNG sales are not included in the Company's firm requirements. The CNG developer's target market is very large institutions and industrial businesses and who are located within reasonable range of a CNG compressor station. While the feasible range of delivery for CNG will vary from CNG provider to CNG provider, a reasonable rule of thumb is the end-user should be within 200 miles of a compressor station.

CNG sales provide significant benefits to firm customers as the margins are a credit to the Company's gas supply costs. The Company believes there are several factors that could lead to higher CNG sales over the planning period, including: (a) improvement in the natural gas price advantage over fuel oil and propane, leading businesses to switch to CNG service since they have no access to pipeline service; and (b) new environmental regulations that are addressed by using natural gas rather than fuel oil and propane, leading businesses to switch to CNG service since they have no access to pipeline service. These factors would lead to higher CNG sales and margin, thus lowering gas supply costs for firm sales customers.

There are also significant risks that could lead to a decrease in CNG sales over the planning period, including: (a) decline in the price advantage over fuel oil and propane; and (b) transfer of CNG production from the Vermont facility to a facility outside of the state. These risks would lead to lower CNG sales and margin and thus higher gas supply costs for firm customers.

Gas Islands

Vermont Gas has successfully developed and operated the state's first "Gas Island" in Middlebury, which has since been interconnected to the Company's transmission system with the completion of the Addison Natural Gas Project in April 2017. A gas island is a natural gas distribution system that is supplied from a source other than a natural gas pipeline. Other supply sources include CNG and Liquefied Natural Gas ("LNG"). Gas islands are utilized as a temporary measure until the distribution system is connected to a natural gas pipeline or when the cost of building and operating a natural gas pipeline is otherwise prohibitive.

The Middlebury gas island was unique – as there are few examples across the country of similar gas islands. Nevertheless, it is a business concept that has growth potential: for example, there is a proposal in New Hampshire to build a gas island in the Hanover area, with Dartmouth College and Dartmouth-Hitchcock Medical Center as major customers of the project.

Gas Islands are generally a niche market that requires an anchor load (or loads) to support the investment and expenses in storage, transportation, and related operating equipment endemic to a natural gas distribution system. In addition, gas islands require a location that is relatively close to the supply source to minimize transportation costs and improve equipment utilization. The Company believes that there may be opportunities for additional gas islands in the state based on certain market conditions and will explore such opportunities as they arise.

Electric Generation

The Company's approach to the development of natural gas fired or fuel cell generation in Vermont is to support developers and operators interested in building and operating generation facilities. Vermont Gas will work with developers expressing an interest in developing generation or co-generation projects in the state, assisting as needed in the design, construction, and operations of natural gas facilities needed to serve potential generation projects.

Nevertheless, Vermont Gas does not anticipate significant growth of natural gas fired or fuel cell generation. It takes several years for a developer to develop, permit, and construct an electric generation project and presently there are no natural gas generation projects in the permitting process in Vermont. Further, the focus on generation sourced from renewable resources adds an additional challenge to the development of natural gas generation. Consequently, the Company has not included any growth from this segment in its forecast.

Heat Pumps

Cold climate heat pumps are becoming more prevalent in the Vermont. While currently it is not cost effective to convert to a heat pump from natural gas, as the technology continues to evolve, the economics may change. Further, some customers may elect to install a heat pump for the cooling benefit. The long-term impact on the Company's market forecast from this technology is unknown at this time. For purposes of this IRP, the impact of heat pumps can be reasonably assumed to be captured in the alternative cases.

Natural Gas Vehicles ("NGVs")

The NGV market represents sales to customers who use natural gas in their vehicles. Presently, the market is very small, representing less than 1 percent of current sales. The Company's price advantage over diesel and gasoline, the primary vehicle fuels in Vermont, has resulted in higher NGV sales over the past five years. However, the size of the NGV market is limited and highly unlikely to increase significantly due to certain market challenges.

First, the incremental cost of natural gas vehicles and associated fueling infrastructure is significant; for some fleets, this concern represents a significant cost barrier, particularly if fuel consumption per vehicle is relatively low (such as a school bus). Second, it has been difficult to secure state and federal funding to support development of natural gas vehicles, as has been the case in other parts of the country. Finally, natural gas is available only in a limited part of the state which, for statewide fleets (like State of Vermont fleet), creates a significant barrier for route and vehicle flexibility.

In spite of these challenges, NGV's can play a significant role in achieving the state's energy goals in the fleet sector including buses and commercial vehicles powered by renewable natural gas. Continued interest by current customers such as the University of Vermont and Casella Waste allow for potential growth in the NGV market; however, the growth potential is limited and would not have a significant impact on the Company's long-term demand forecast.

Appendix

Appendix: Description of Customer Forecast Method

Market	Methodology	Forecast of Economic Variables
Residential New Construction ("RNC")	Customer growth for RNC is based on projected population growth applied to the historical relationship between RNC customer growth and population growth. The historical relationship shows that the Company adds one RNC customer for every 3.44 increase in the population.	The forecast for population growth taken from Vermont Department of Labor (VDOL).[3] Base population growth of 0.33% for Chittenden and Franklin County is based on an average of the low and high population scenarios. High population growth of 0.46% for Chittenden and Franklin County is based on the high population scenario. Low population growth of 0.20% for Chittenden and Franklin County is based on the low population growth scenario. Population in Addison County and Rutland County is expected to decline during the planning period; thus, the Company assumed no RNC growth in the Addison County and Rutland County communities.
Residential In-Fill	Customer growth for residential in-fill is based on an in-fill conversion rate (i.e., the percent of in-fill customers who convert to natural gas in a given years) applied to in-fill market potential. The in-fill conversion rate is based on the price advantage applied to the historical relationship between price advantage and infill conversion rates. The estimated market potential is presently 6,155 customers.[4] Customer growth for residential in-fill includes Addison and Chittenden County customers who do not convert in the first year that natural gas service is available.	The in-fill conversion rate is based on a linear relationship between historical conversion rates and the Company's price advantage over heating oil. Base Growth: the infill conversion rate over the planning period averages 5.7%. High Growth: the in-fill conversion rate over the planning period averages 7.1%. Low Growth: the in-fill conversion rate over the planning period averages 3.9%.
Residential Main Extensions ("M/E")	Customer growth for residential M/E is based on the first-year M/E conversion rates applied to the M/E market potential. First-year M/E conversion rates are based on the historical relationship between the Company's price advantage over heating oil and first-year M/E conversion rates. M/E market potential is based on three factors: (a) the available inventory of feasible expansion projects, (b) the	The first-year M/E conversion rate is based on a linear relationship between historical conversion rates and the Company price advantage over heating oil. Base Growth: the first-year M/E conversion rate over the planning period averages 36.1%. High Growth: the first-year M/E conversion

3 Vermont Department of Labor (VDOL), 2015 Economic – Demographic Profile, http://www.vtlmi.info/profile2015.pdf
4 Estimated market potential is based on a comparison of service area housing units and residential customers.

Market	Methodology	Forecast of Economic Variables
	physical ability to construct such expansions, and (c) the first-year conversion rates. A feasible expansion project is one that will generally pass two financial tests: 1. At 100% saturation, the margin generated by the consumption of the potential customers over a period of ten years will recover the cost of construction at Vermont Gas' allowed rate of return. 2. The first-year actual growth of margin generated by the consumption of the actual customers when blended with the financials of all of Vermont Gas' other actual growth projects meets or exceeds our allowed rate of return. This two-part test is intended to ensure that, overtime, main extensions do not result in upward pressure on rates. Estimated market potential in Chittenden and Franklin Counties is 1,155residential customers. Estimated market potential in Addison County is 1,860 residential customers and 546 C&I customers, respectively. It is important to note that M/E customers who do not convert to natural gas service in the first year are considered potential in-fill customers in future years	rate over the planning period averages 41.1%. Low Growth: the first-year M/E conversion rate over the planning period averages 21.9%.
Commercial and Industrial ("C&I")	Customer growth for the C&I class is based on historical relationship between added C&I customers and change in state gross domestic product (GDP).	State GDP growth from Moody's. Base growth GDP increases average $0.5 billion per year over the forecast period. High growth GDP increases averages $0.5 billion per year, but is higher than the base period growth in the early years. Low growth GDP increases averages $0.5 billion per year, but is lower than the base GDP growth in the early years.

SECTION 3: SUPPLY-SIDE PLANNING

INTRODUCTION AND OVERVIEW

The integrated resource plan provides a detailed description of the supply planning environment, objectives, potential resources, current resources, and potential portfolios to meet the supply requirements of the Company's firm and interruptible customers.

The starting point for the supply plan is the Company's current portfolio of gas supply, pipeline transportation and storage contracts along with an array of assumptions regarding supply pricing, pipeline tolls, possible future supply alternatives and projected market requirements. However, the planning process is not static and thus the Plan describes the Company's approach to supply planning and opportunities to reshape the resource portfolio as conditions change.

SUPPLY PLANNING ENVIRONMENT

Historically, Vermont Gas has been predominantly supplied by natural gas sourced from the Western Canada Supply Basin ("WCSB"). The natural gas supplies from the WCSB are transported to Vermont via the TransCanada Pipelines Limited ("TCPL" or "TransCanada") Canadian Mainline from Empress, Alberta to Philipsburg, Quebec.

The Canadian-U.S. natural gas market has undergone fundamental changes that have affected natural gas supplies to Vermont, as well as the transportation paths utilized to deliver that natural gas. Specifically, the volume of natural gas shipped from the WCSB to markets in Eastern Canada and the U.S. Northeast has declined. The decline is a result of certain market dynamics including: (1) decreased production of conventional natural gas resources in the WCSB; (2) increasing natural gas consumption by certain market segments in Alberta (i.e., industrial-oil sands and power generation); and (3) increasing natural gas production from the Marcellus and Utica shale basins, which are geographically closer to the traditional demand markets. In addition, WCSB producers are seeking alternative markets for existing and new natural gas production, including the export of liquefied natural gas ("LNG") from Western Canada to natural gas markets throughout the world.

The change in the natural gas markets has resulted in changes to the pipeline transportation markets. First, increasing natural gas production from the Marcellus and Utica shale basins has resulted in pipeline infrastructure that has been constructed or is planned or under construction to connect shale gas to markets in the U.S. and Canada. The second, declining natural gas production in WCSB has resulted in decreased utilization of the TCPL mainline, putting upward pressure on pipeline tolls as the fixed costs are spread to fewer transporters. To counter the trend, TransCanada is seeking approval to bring WCSB supply to Dawn with a long term fixed priced toll below current tolls. WCSB producers have signed up for the service and the plan is under review by Canada's National Energy Board ("NEB"). Energy Transfer is building the Rover Pipeline to deliver up to 3.25 Bcf/day from Marcellus and Utica Shale to markets in the Midwestern US and Dawn/Parkway markets in Ontario. Additional similar projects are in the planning stages. To complement these developments, TransCanada and Union are continuing to increase pipeline capacity from Ontario to Eastern Canada and the United States with pipelines and compressor additions. The aforementioned developments have resulted in lower Dawn and Parkway basis futures, which will benefit Vermont Gas customers.

As tolls have risen, so-called "long haul" shippers (customers contracting with TCPL from Empress, Alberta to points in eastern Canada) have transitioned to "short haul" service (customers contracting with TCPL from the Union Parkway Belt, Ontario to points east). As a result, much of the western TCPL system is under-utilized. Currently, it is more cost effective for TCPL shippers in the east, including Vermont Gas, to hold short-haul capacity and purchase natural gas at Parkway (or a the closely related market point known as "Dawn") than hold long-haul capacity and purchase natural gas at Empress.

In response to these changing market conditions, Vermont Gas has undertaken two fundamental initiatives to minimize supply costs while maintaining flexibility and stability. The first is a move from a mix of TCPL long haul and short haul capacity to 100% short haul capacity. This move was completed on January 1, 2017. The second change related to storage capacity. The move to 100% short haul capacity on TCPL mitigated one of the drivers behind the original decision to add storage to the supply portfolio back in the mid 1990's: the need to optimize long-haul capacity. However, storage provides the operational flexibility that is paramount to daily operations and still plays a key role in VGS' portfolio. The Company has changed its maximum storage capacity from 2.0 Bcf to 1.6 Bcf, reducing storage costs, but maintaining sufficient flexibility to serve winter loads.

PLANNING OBJECTIVES

The Company relies on the following four objectives to guide development of its supply plan and in making supply resource decisions:

Reliability: Ensure reliable supply to meet firm customers' annual and peak-day requirements, while minimizing curtailments to interruptible customers to maximize interruptible margins.

Flexibility: Ensure capacity and supply contracts are sufficiently flexible to optimize supply assets under various scenarios.

Stability: Minimize the risk of gas price volatility and its effect on rates and earnings through the use of financial derivatives.

Cost-Effective: Ensure the resulting portfolio is cost-effective under a variety of scenarios with due consideration given to reliability, flexibility, and stability.

SUPPLY RESOURCES

There are a number of supply and capacity resources that could be available to Vermont Gas including TCPL transportation, storage, long and short-term supply contracts, renewable natural gas ("RNG"), liquefied natural gas ("LNG"), compressed natural gas ("CNG"), energy efficiency, and propane air. Each of these resources has a different cost, reliability and flexibility profile. While Vermont Gas' current portfolio provides sufficient capacity for the next several years, as Vermont Gas' capacity resources with TCPL become eligible for de-contracting (non-renewal), the supply portfolio will be revisited. Options to be considered, which will be evaluated against the four objectives of reliability, flexibility, stability, and cost effectiveness, are described below.

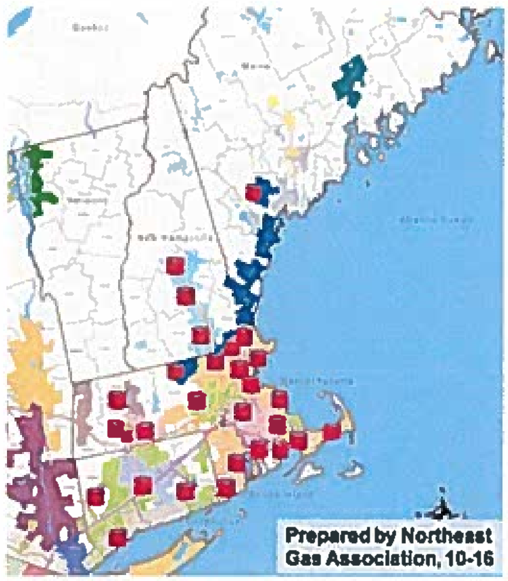
TCPL Transportation - Because Vermont Gas is only physically interconnected to one pipeline system, the TCPL system; this has been Vermont Gas' primary source of upstream capacity. TCPL has a suite of offerings, including firm "long-haul" providing capacity from the Western Canadian supply basin, firm "short-haul" providing capacity from Eastern Canada (Parkway), storage transportation services, and various interruptible resources. These offerings have differing tolls, flexibility features, lead times, and commitment terms. TCPL resources do not provide natural gas supply; rather they provide a means to transport natural gas supplies purchased from a third party to the Vermont market.

Storage – Storage is a resource that provides daily flexibility to balance changing demand. While not a source of supply itself, storage allows Vermont Gas to "inject" natural gas into storage in the summer when market demands are low and "withdraw" it in the winter when the customer demand for natural gas is greater. Storage also enables more stable pricing to customers and protects customers from price spikes on the very coldest days in the winter. Storage contracts vary in terms of overall storage capacity or "space," maximum quantity of natural gas that can be injected or withdrawn daily, and other operational features.

LNG Peaking - LNG is a widely used peak shaving alternative to pipeline capacity as demonstrated in the Figure 3.1 below. Unlike storage and TCPL capacity, LNG peaking provides both a capacity resource and a supply resource, as such it is considered from both perspectives. Since the last IRP, LNG supply is now available from Montreal, which has increased the competition and available supply. LNG could also provide system reliability during pipeline repairs and system maintenance.

Figure 3.1: LNG Facilities in New England

Figure 3.1 illustrates Utility owned and operated LNG Facility in New England



Propane Air – Vermont Gas currently has an on-system resource in the form of a propane air plant ("PAP"). The PAP is used to inject a mixture of propane and air into the natural gas supply and increases available pipeline capacity and serves as a supplemental supply. In considering an expansion of these resources it is critical to note that the current propane air plant operates near capacity and is limited by the flow passing through the plant. Expansion of propane air capability would require additional investment in pipeline upgrades.

CNG – CNG is a potentially available peaking resource for Vermont Gas. It could be used as short-term storage option during high demand periods or emergency supply during pipeline disruptions. Vermont Gas' largest customer operates a CNG facility in Milton, Vermont. As a peaking option, Vermont Gas could contract with this operator or an alternate supplier to fill trucks in advance of a pending peak day and deliver as needed to serve firm customers.

Supply contracts - Vermont Gas will have choices of spot purchases short-term, medium-term and long-term supply contracts with numerous suppliers. Vermont Gas utilizes industry-standard contracts (NAESB and GasEDI) for natural gas supply transactions. These contracts have no purchase obligations until a transaction is executed. The term, quantity, and price of each transaction is negotiated at the time of purchase.

Renewable Natural Gas – Vermont Gas has proposed a voluntary RNG program for its customers. Vermont Gas expects RNG supply will be obtained from both off system and on system suppliers and will be used to offset other natural gas purchases. Vermont Gas is working with suppliers from various RNG projects in North America and in-state.

Hedging - Hedging is a financial tool available to the Company to mitigate customer exposure to price volatility. Vermont Gas' hedging program is designed around minimizing price volatility while replicating market pricing over the long term.

Energy Efficiency – Vermont Gas' Energy Efficiency Utility ("EEU") reduces customer natural gas requirements on a daily, monthly and annual basis. From a capacity perspective, Vermont Gas calculates design day savings from the EEU programs and incorporates the savings in the peak day forecast. The EEU contribution to design day savings and associated costs will continue to be evaluated when projecting additional upstream and downstream capacity.

Asset Management – Asset Management Agreements ("AMA") allow a third-party to utilize capacity that is not needed during non-peak days and shares the profits with Vermont Gas. The agreements are usually a combination of a fixed payment to Vermont Gas as well as a sharing percentage above the fixed payment. The agreements allow Vermont Gas to utilize the capacity during days when demand is high on the Vermont Gas System and the marketer to optimize the rest. AMA revenues are not guaranteed, but are a tool available to Vermont Gas to help lower firm natural gas rates.

Additional Pipelines Interconnects – Looking out longer than the 20 year planning horizon of this plan, it is possible that opportunities could develop to interconnect with the U.S. pipeline network. An interconnection would add additional supply resource, transportation diversity, extend gas service into additional areas of Vermont, and provide redundancy for the TCPL system. Vermont Gas will continue to monitor the new pipelines installation in the northeastern

United States and investigate opportunities as they present themselves.

EVALUATION OF SUPPLY RESOURCES

The current supply portfolio is representative of the significant changes that have occurred in the natural gas industry described above. The Company's current supply portfolio is provided in the table below and forms the basis for the scenarios developed in this Plan.

Table 3.1: Current Supply Portfolio

The table uses a 1.027 Btu conversion factor to convert Mmbtu to Mcf.[1]

Capacity Provider	Receipt Point	Delivery Point	Type of Service	MDQ (Mcf)	Expiration	Comment
TCPL Firm Long- Haul Non-Renew[2]	Empress	Phillipsburg	Firm, year round	9	10/31/17	
TCPL Firm Short-Haul Transportation	Parkway	Philipsburg	Firm, year round	20,304	10/31/22	Two contracts of 9,229 and 11.075
TCPL Firm Short-Haul Transportation	Parkway	Philipsburg	Firm, year round	7,383	10/31/23	
TCPL Firm Short-Haul Transportation	Parkway	Philipsburg	Firm, year round	17,074	10/31/31	Two contracts of 5,999 and 11,075
TCPL Firm Short-Haul Transportation	Parkway	Philipsburg	Firm, year round	5537	10/31/31	
Union Firm Transportation	Dawn	Parkway	Firm year-round	18,458	10/31/19	Linked to TCPL storage transportation
Union Firm Transportation	Dawn	Parkway	Firm year-round	461	10/31/20	Linked to TCPL storage transportation
Union Firm Transportation	Dawn	Parkway	Firm year-round	7,475	10/31/24	Linked to TCPL storage transportation
TCPL Storage Transportation	Parkway	Philipsburg	Storage Transportation	18,715	10/31/22	
Propane Air Plant	On-system		Peaking	7,730	N/A	
Total Capacity				76.752		
FY 2017 Peak Day				73,789		
Excess/(Deficit)				2,963		

[1] Average TCPL heat rate to Philipsburg for the prior year.

[2] TCPL tariff requires a Long Haul contract to hold STS Contract. This contract meets the requirements

Evaluation of Supply Portfolio against Supply Criteria

Over the last several years, Vermont Gas has evolved its supply portfolio to meet the objectives previously listed, resulting in a more flexible supply portfolio. The specific strategies employed for each of the objectives are described below.

Reliability: Vermont Gas has completed the transition to 100% short-haul capacity on the TransCanada Pipelines ("TCPL") system effective January 1, 2017. This transition has resulted in lower gas costs for customers and access to more liquid purchase points without sacrificing reliability. In addition, Vermont Gas is planning on adding an additional 10,000 GJ of short-haul capacity on the TCPL system. This additional capacity will require TCPL to construct additional pipeline just north of the Vermont/Canadian border, which will provide additional reliability for VGS' customers. TCPL anticipates that there will be delays in acquiring the necessary permits for TCPL to begin construction, thereby delaying the Company's access to the additional 10,000 GJ of short-haul capacity for up to a year. Vermont Gas has sufficient capacity to meet projected design day and annual firm requirements in the interim while TCPL constructs the additional pipeline.

Flexibility: Vermont Gas will have the flexibility to relinquish TCPL capacity in October, 2022 and again in October, 2023, providing additional flexibility to the Company should VGS market conditions change. This flexibility is particularly critical given the potential load ramifications of a low-carbon future.

Vermont Gas also expects to provide flexibility to its customers. Vermont Gas has been working with Renewable Natural Gas ("RNG") suppliers, both on and off its system, to provide customers with additional supply choices. Vermont Gas filed with its regulators in October, 2015 for an approval of an RNG program and ability to offer RNG tariff service to customers.

The RNG program will be voluntary for Vermont Gas customers, as they will be able to choose to purchase between 0% and 100% of their overall purchases of RNG. Assuming regulatory approval of the RNG program, the Company will offer this service to both their firm and interruptible customers. Off system RNG supply will be delivered to VGS at a market hub along with 100% of its renewable attributes. Vermont Gas will used its existing capacity contracts to deliver the RNG to Vermont. In addition, Vermont Gas is in discussion with an on system RNG supply provider that will be delivered directly into the Vermont Gas distribution system. Vermont Gas plans to ramp up RNG supply volumes as the demand grows.

Vermont Gas anticipates that it will match RNG costs with corresponding customer purchases and has several mitigation strategies to address imbalances. As a last resort RNG costs may be included in the quarterly Purchased Gas Adjustment filings.

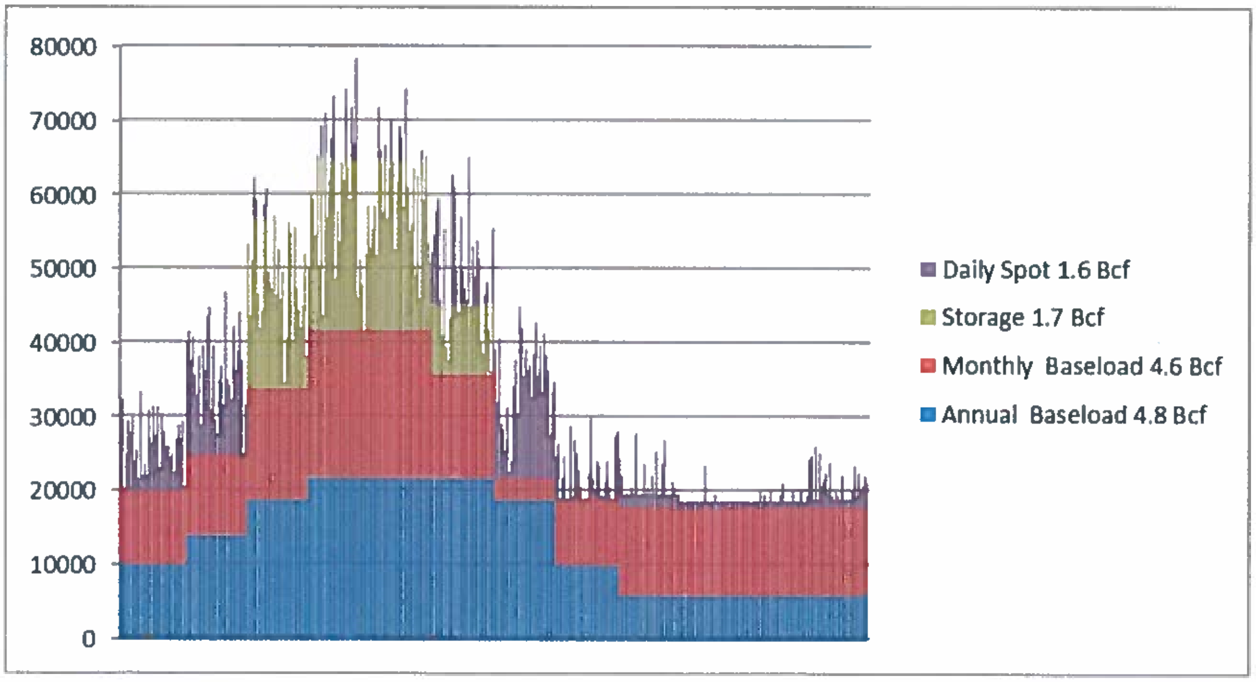
The RNG program is an important part of both the Company and the State of Vermont's carbon reduction goals. The program will allow both residential and commercial customers the choice to reduce their carbon footprint by using RNG.

Finally, Vermont Gas is using short and medium-term supply contracts (one month to one year) rather than long-term supply contracts to maintain additional supply flexibility.

By supplementing base load contracts with spot purchases, Vermont Gas retains the flexibility to adjust its purchases to changes during the year. A typical fiscal year (October through September) is shown below.

Figure 3.2: Annual Purchase Example

Figure 3.2 illustrates the variation between annual base load, storage and daily spot purchases.



Stability: While wholesale natural gas prices remain relatively low, some volatility in pricing remains. As a result, Vermont Gas hedges portions of its supply portfolio to reduce price volatility and provide customers with more stable pricing. To facilitate hedging, Vermont Gas ensures that its firm supply contracts are indexed to market hubs that are sufficiently liquid to be readily hedged. Further, because storage commodity costs are reflected in rates at the weighted average cost of storage inventory at the time of utilization, storage provides an additional degree of price stability.

Cost-effective: As used herein, cost-effective means least cost relative to alternatives, with due consideration given to reliability, flexibility, stability and other policy considerations. Because the natural gas market is dynamic, a portfolio that is cost-effective under one set of assumptions may not be cost-effective in a different scenario. With the current capacity and supply portfolio, Vermont Gas has structured a portfolio that will be cost-effective under a variety of circumstances.

As noted above, Vermont Gas has migrated its portfolio to be short-haul based. This has resulted in lower gas costs. Further, the Parkway receipt point is very liquid, thus ensuring the availability of competitively-priced supply for Vermont Gas and its customers. Finally, by seeking additional capacity for 2017/2018, Vermont Gas was able to take advantage of "rolled in" tolling, such that the construction of the additional pipeline will be shared by all shippers on the TCPL system, not solely Vermont Gas.

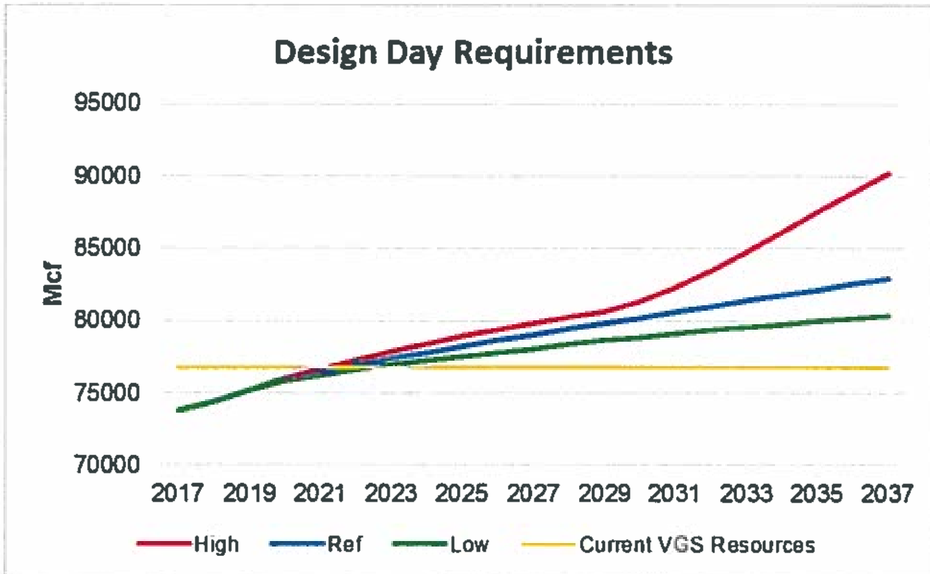
EVALUATING SUPPLY PORTFOLIOS

Prior to evaluating the supply resources described above against the planning criteria it is necessary to forecast design day and total system loads. These are discussed below.

Design Day The design day methodology and calculation was previously described in the Marketing chapter. The forecasted design day requirements compared to the current capacity portfolio is shown in Figure 3.3 below.

Figure 3.3: Design Day Requirements

Figure 3.3 illustrates Design Day forecast under three different cases: base growth, high growth, and low growth and compares it to current upstream capacity resources.



Total System Loads

Vermont Gas utilizes an Excel-based daily load dispatch model to calculate firm and interruptible sales which form the basis of total system loads. As described later, this model also generates daily load requirements and dispatches available supply resources prior to calculating gas costs. The methodology for calculating total system loads is described below.

Firm Sales The first step in the process is to develop firm sales using the following methodology:

Sales = (Cust * (Heat use- DSM) * HDD)) + (Cust * (Base – DSM))

Sales = Monthly sales

Cust = Monthly number of customers

HDD = 10 year average heating degree days (NOAA, Burlington VT)

Heat use = Heating use per customer per heating degree day.

Base = Base use per customer per month

DSM = DSM savings adjustment

Heating and base usage factors are derived from historic data using a 3 year average. The firm customer growth forecasts by rate class are contained within the marketing section of this plan and are a key input to the expected monthly number of customers.

This forecasting approach is consistent with Vermont Gas' internal planning models and prior regulatory filings. Please note that this approach assumes an average usage profile by rate class to each new customers and care must be taken if substantially smaller or larger customers are projected to be added. In these situations, explicit adjustments are may be made to the applicable usage factors to accurately reflect the expected new load.

Interruptible Sales – Interruptible customer growth forecasts are contained within the marketing section of this plan. Interruptible sales and revenue utilize a similar methodology as the firm customer class described above, with the following exceptions:

- Customer sales are forecasted on an individual basis
- Sales are inclusive of curtailments

Developing the Supply Portfolio and Resulting Cost of Gas

After developing the total system sales forecast, supply resource decisions are measured utilizing the same Excel spreadsheet to dispatch supply resources to meet daily and annual demand requirements under design and normal weather conditions, subject to the constraints of the underlying supply resource contracts.

Design day requirements are used to determine the amount of peak-day capacity resources needed and annual forecasted sales are used to determine the amount of annual supply required to meet those demands. In evaluating annual supply resources, operational constraints such as daily and annual storage limits, maximum daily spot purchases and the resulting curtailments must be considered.

Based on the customer demands calculated as described above and the supply objectives contained in this Plan, Vermont Gas' the proposed capacity portfolio for the next twenty years is shown in Table 3.2 below.

Table 3.2

Proposed Base Competitive Position Capacity Portfolio

	2017	2022	2027	2032	2037
Peak Day Mcfd	73,789	76,929	79,062	81,014	82,966
Resource Mcfd					
TCPL FT Short Haul (1)	50,298	59,527	59,527	59,527	59,527
TCPL Storage Trans.	18,715	18,715	18,715	18,715	18,715
Union Firm Transport (2)	26,395	26,395	26,395	26,395	26,395
Propane	7,730	7,730	7,730	7,730	7,730
Total	76,743	85,972	85,972	85,972	85,972
Excess	2,954	9,043	6,910	4,958	3,066
Maximum Storage Bcf	1.6	1.6	1.6	1.6	1.6

(1) Vermont Gas has a contractual right to de-contract a portion of this capacity effective November 1, 2022 and November 1, 2023 depending on market conditions. See Table 4.1 above for available volumes.

(2) Used to transport storage inventory to/from Dawn/Parkway. Does not add additional peak-day capacity and is therefore not included in capacity totals.

It is important to reiterate that this is the proposed capacity portfolio under a "base case" set of assumptions. Over the next three to five years Vermont Gas does not need to make any significant capacity commitments beyond what has already been committed to. Further, as noted earlier, the Company has the flexibility to readjust its capacity portfolio beginning in 2022. Therefore the actual capacity portfolio for 2022 forward will likely be different than the table above as the Company responds to changing market conditions.

Gas Costs

The final step in the process is to calculate gas costs. The same Excel model is used to calculate the overall supply costs, broken down by demand-related which refers to those costs associated with capacity contracts, and commodity-related, which refers to the cost of the natural gas itself. The overall supply costs can then be used to compare the cost implications of the current and alternative supply portfolios.

For purposes of this Plan, gas supply costs were calculated based on the following components and associated set of assumptions: (a) pipeline and storage fixed costs, based on current fixed charges; (b) pipeline and storage variable costs, based on current variable costs; and (c) wholesale commodity costs, based on NYMEX forecasts adjusted to reflect the basis differential between Henry Hub (supply point for natural gas for NYMEX) and the market purchase points used by Vermont Gas. For purposes of forecasting natural gas wholesale prices, the Plan relied on natural gas prices forecasts prepared by the Energy Information Administration ("EIA") under three different scenarios.

1) **Reference case-** The "Reference" case was used for the Base competitive scenario and base customer growth.
2) **High Price Advantage Case -** The EIA forecast used for the "High" price advantage case and high growth scenario is referenced as the "High Oil" scenario by EIA. Under that scenario high oil prices result in a wider spread between wholesale natural gas prices and wholesale oil prices.
3) **Low Price Advantage Case -**The EIA forecast used for the "Low" price advantage case and low growth scenario is referenced as the "Low Oil" scenario by EIA. In that scenario the spread between wholesale oil and wholesale natural gas prices is narrowed.

The resulting cost of gas is a key input to the financial modeling provided later in this Plan. It is critical to note that these are planning assumptions and should not be interpreted as actual forecasts of gas costs over the planning horizon. Rather the supply discussion is a description of the process to be employed in making supply decisions and an analysis of the sensitivity of overall gas costs to various changes in wholesale natural gas market. The key is to consistently and frequently monitor the current supply portfolio and assess alternatives and their ability to meet the planning objectives. A supply portfolio that is reliable, flexible, stable and cost-effective is the outcome we are constantly pursuing for the benefit of our customers.

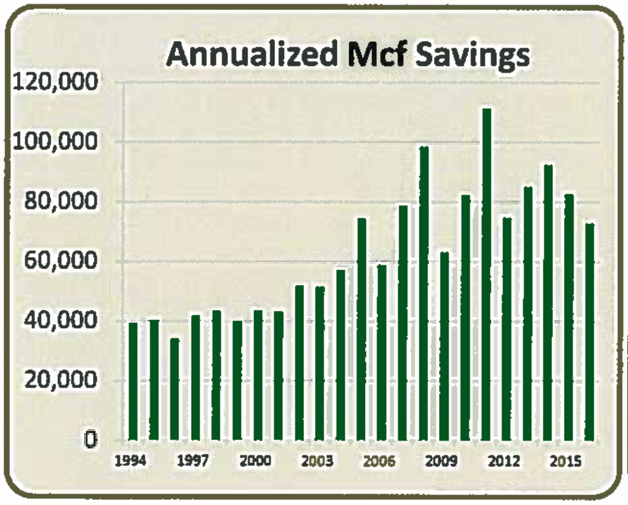
SECTION 4: ENERGY EFFICIENCY

Vermont Gas Systems, Inc. ("VGS") implemented its first energy efficiency programs in 1993. VGS currently offers three energy efficiency programs[1] for each of its residential and commercial sectors. The programs offer both technical and financial assistance and are comprehensive. VGS partners with other energy efficiency groups including Champlain Valley Office of Economic and Opportunity ("CVOEO"), Burlington Electric Department ("BED") and Efficiency Vermont ("EVT") to reduce program overlap, keep costs low, and streamline customer service. Each of the three programs is described below and is essentially the same scope for residential and commercial customers, although the individual measures will vary based upon customer size:

- Equipment Replacement – A lost opportunity program that aims to assist customers with failed or soon-to-fail equipment. Customers are provided incentives to install a higher efficient unit than they would have without the program.
- New Construction – This program is also considered a lost opportunity program and encourages builders to construct higher efficient buildings than otherwise without the program. Incentives are available for items such as better insulating, higher efficient appliances and higher efficient heating systems. Incentives under this program are provided directly to the builder.
- Retrofit – This program targets existing buildings. It is primarily audit-based and is designed to increase building shell efficiency and/or equipment efficiency.

Since program inception through end of calendar year 2016, VGS contributed more than $35 million in utility spending and achieved almost 1.5 Bcf in annualized savings. Savings and investments from program inception through 2016 are reflected in Figure 4.1 and Figure 4.2.

1 A full description of each program, including historical performance, incentive structures, and detailed program offering, is not contained in this IRP. For full program descriptions and offerings please reference the most recent CY 2016 Annual Plan located at the following link;
http://psb.vermont.gov/sites/psbnew/files/doc_library/vgs-annual-plan.pdf



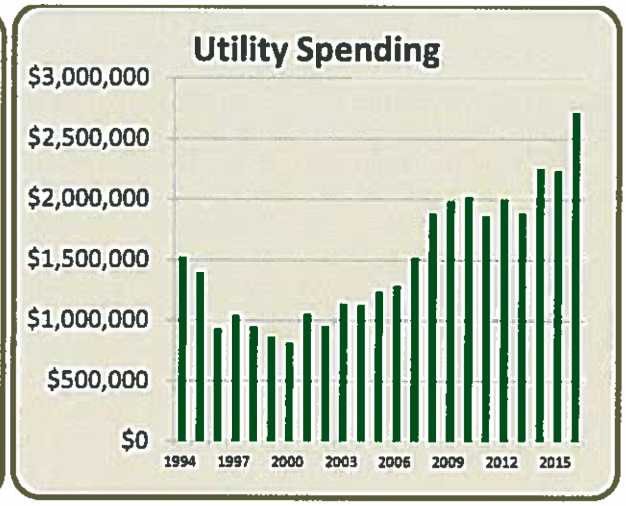


Figure 4.1 Historical Energy Efficiency Annualized Mcf Savings[2] and Figure 4.2 Utility Spending

The following section will give hi-lights on the procedural history leading up to VGS' appointment as an Energy Efficiency Utility, effective January, 2016, and following the Order of Appointment model.

Procedural History

In 2009, the Public Service Board ("Board") issued an Order in Docket No. 7466 announcing the change of the Energy Efficiency Utility ("EEU") structure moving from a contract model to an Order of Appointment model.

Effective April 17, 2015 the Board issued an Order of Appointment[3] to VGS to serve as an EEU as authorized in 30 V.S.A. § 209(d)(5).

Effective January 1, 2016, Vermont Gas formally began operating under the EEU model, which impacted reporting, budgeting and paying for the programs. Prior to becoming an EEU the efficiency programs, excluding payroll and labor, were paid through rates via a "book and defer" process where the program spending became a part of rate cases and were then built into

2 Calendar Year 2016 savings do not include evaluation and verification of commercial or custom residential new construction program

3 The current P&A Document can be found at the following link; http://psb.vermont.gov/sites/psb/files/orders/2015/2015-04/7676%20Order%20re%20VGS%20Order%20of%20Appointment%20and%20P%20and%20A%20Document.pdf

rates. Payroll and labor were also included in Vermont Gas' rates but were not defered. As a result of becoming an EEU, the "pay as you go" model was adopted with the program costs included as an Energy Efficiency Charge ("EEC") as a line item in the monthly bill and Vermont Gas' distribution rates were reduced to reflect the expenses moved to the EEU. Please note that residual amounts related to pre-EEU charges that had not yet been amortized are still collected in VGS' distribution rates. These amounts are being amortized over 10 years.

Both Burlington Electric Department ("BED") and Efficiency Vermont("EVT") were already serving as Energy Efficiency Utilities and had recently completed their Demand Resoure Plan ("DRP") for calendar years 2015 – 2017. In order for efficiency in planning, it was determined that all EEU's be on the same DRP schedule. As a result, VGS developed and implemented, the Board approved, 2016-2017 Transition Period Plan ("TPP") to act as a bridge until the next round of DRP proceedings for years 2018-2020. VGS recently completed Year One (2016) and is currently in Year Two (2017) of the final year of the two year TPP plan. The 2018-2020 DRP is in progress and will establish budgets and savings goals for those years and identify indicative savings and budgets through 2037. The specific savings and budget goals beyond 2020 will be established by subsequent DRP proceedings for BED, EVT and VGS. Vermont Gas anticipates that in subsequent DRP proceedings, many of the issues identified in the executive summary that will impact Vermont's progress toward a low-carbon future will be further developed and be more explicitly addressed in future DRP proceedings.

As part of the DRP proceedings a potential study was conducted which included maximum and realistic achievable potential as well as modeling three scenario plans. In addition to collaborating with VGS regarding the modeling of energy efficiency programs, the Department of Public Service ("Department") conducted an internal rate and bill impact analysis and proposed development and support service budgets. To date, VGS and the Department have agreed on and filed the following resource acquisition costs ("RA"), development and support services ("DSS") and thermal clearing house budgets that pertain to 2018-2020 along with projected flat annual budgets for 2021-2037 as reflected in the following Table 4.1.

Table 4.1 reflects the proposed RA and DSS budgets by the Department and VGS

	2018	2019	2020	3 Yr. Total	2021-2037
Resource Acquisition (RA)	$2,889,201	$3,014,426	$3,030,476	$8,934,103	$3,030,476
Dev. & Support Services (DSS)	$259,757	$267,135	$269,536	$796,428	$269,536
Thermal Clearing House	$14,880	$14,880	$14,880	$44,640	$14,880
VGS Total	**$3,163,838**	**$3,296,441**	**$3,314,892**	**$9,775,171**	**$3,314,892**

The Department and VGS are in agreement on the costs related to each of the budget categories listed as well as keeping the corresponding EEC charge flat or declining. The Department and VGS currently disagree by a small margin in terms of the acquisition costs per Mcf that will be used to determine the annual incremental Mcf savings. The following Table 4.2 reflect both the Department and VGS' proposed acquisition costs based upon the agreed upon budgets.

Table 4.2 reflects proposed acquisition costs by calendar year

$/Mcf Acquisition Costs	2018	2019	2020	3 Yr. Total	2021-2037
DPS recommended	$36.49	$36.80	$36.94	$36.75	$36.89
VGS recommended	$39.39	$39.62	$39.97	$39.66	$39.97
AVG	$37.94	$38.21	$38.45	$38.20	$38.43

For purposes of this IRP, VGS used the average of the yield proposals made by the Department and VGS. The average $/Mcf was applied to the agreed upon resource acquisition budget to come up with the annualized incremental Mcf saved per year as shown in Table 4.3 and used for screening purposes in this IRP. For modeling purposes in the IRP, VGS combined results from the potential study along with historical results to determine the estimated savings by sector and the impact to peak day savings.

Table 4.3 Reflects the average annualized Mcf saved using the acquisitions rates from Table 4.2

Annualized Incremental Mcf Saved	2018	2019	2020	3 Year Total	2021-2037
Department recommended	79,178	81,914	82,038	243,129	82,149
VGS recommended	73,347	76,082	75,826	225,255	75,826
Average Annual Mcf Saved	76,151	78,890	78,809	233,851	78,861

Please note that there will be a realization rate applied to the Mcf's saved listed in Table 4.3 based on the savings verification, which is currently underway. The negotiated realization rate will be a direct multiplier and most likely reduce the savings goals.

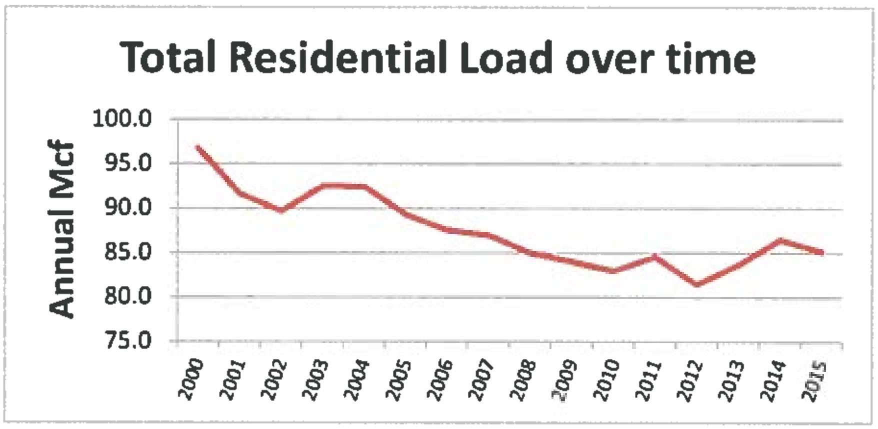


Figure 4.3 Reflects declining average residential usage over time.

VGS recognizes that there are other alternate fuel choices for customers and VGS is committed to keeping rates low. Accordingly its proposals for energy efficiency savings are made with an objective of flat to declining EEC charges. This IRP reflects that as shown in Table 4.4 below.

Table 4.4 reflects proposed 2018-2037 budgets along with corresponding Energy Efficiency Charge projected change from prior year

VGS Budget & Rate Impact	2017	2018	2019	2020-2037
VGS Budget*	$3,221,755	$3,387,432	$3,528,171	$3,535,423
Budget % Change from Previous Year	-	5.14%	4.15%	0.21%

Estimated Average EEC Rates ($/ccf)	$0.03800	$0.0378	$0.0377	$0.0376
EEC % change from previous year		-0.53%	-0.26%	-0.27%

* CY2017 EEC charge includes under collections from prior year. EEC rates include estimates for growth.

Local Market Challenges & Opportunities

While VGS is a regulated fuel, it also needs to remain competitive. VGS has been operating its efficiency programs for over 20 years and as a result has mature programs. The following are some of the challenges as well as opportunities that are anticipated in this plan.

- VGS has been implementing energy efficiency measures since 1994. This results in the highest users already having participated leaving a smaller pool of low users where the $/Mcf savings (yield) could potentially be higher.

- The Department of Energy ("DOE")'s furnace standards proposal will result in higher baselines. The DOE issued a Supplemental Notice of Proposed Rulemaking ("SNOPR") that most new furnaces would reach an efficiency of at least 92%. While facing challenges from several constituent groups, the new proposal would increase the baseline for furnaces over 55,000 Btu/hr from the current 80% to 92% AFUE. Implementation date of this new standard is yet unknown. While the legislation is welcome from an enhanced efficiency perspective, it will however lead to lower savings and possibly higher acquisition rates.

- Impact of both residential and commercial energy codes and standards as well as increasing baselines over the next 20 years are expected to have a material impact on savings, which will in turn impact the cost effectiveness of measures and in turn programs. Again, while the increase in both codes in baselines is welcome this will lead to smaller savings.

- Unknown evaluation realization rates results for programs that have not yet undergone formal M&V.

- Vermont Gas' Addison County goal is to have 30% participation in its energy efficiency programs by new Addison County customers by year three. By comparison, in recent expansions the total of the commercial and residential sectors on average achieved 19%

program participation after year two, 22% participation after year three and 24% after year four. The Addison County market offers a new opportunity to expand the current footprint with natural gas programs and the potential for additional savings. The VGS sales and marketing staff are aggressively marketing the efficiency programs at the same time gas services are being offered as well as sharing EVT's efficiency offerings as well to ensure customers have choices regardless of fuel type. The savings included in this IRP reflect this aggressive outreach in Addison.

Conclusions

In addition to RA and DSS costs associated in operating the EEU programs, there are additional fiscal agent fees, independent evaluation of program costs as well as costs incurred by the Department. The projected budgeted annualized Mcf Savings, the overall expected total program costs [4] and the total program associated benefit to cost ratios[5] without externalities as well as the societal benefits to costs are in the following Table 4.5.

Table 4.5 VGS Projected Annualized Mcf Savings, total utility spending and benefits to costs (with and without externalities)

	2018	2019	2020	2021-2037
Annual Mcf Saved	76,151	78,890	78,809	78,861
EEU Total Budget	$3,387,432	$3,528,171	$3,535,423	$3,387,432
Benefit to Cost Ratio (without externalities)*	4.92	4.96	5.01	5.1 **
Societal Benefit to Cost Ratio*	8.39	8.43	8.49	8.61 **

* Assumes firm rates and screened at program level using most recent Board Approved AESC screening tool

** Screened Using Implementation Year 2021

Whether operating its owner energy programs or as a result of becoming an Energy Efficiency Utility, VGS remains laser focused in helping its customers save energy. Not only will this lead to lower natural gas bills for VGS customers, but it also helps decrease greenhouse

4 Includes Resource Acquisition Costs, Development & Support Services, Fiscal Agent Fees, DPS costs and EM&V
5 Avoided Costs divided by the benefits screened using the most recent Board Approved AESC screening model.

gas emissions. The energy efficiency program helps customers make informed energy efficiency decisions as well as guides them through the process. VGS' partnerships with BED, EVT, CVOEO and the Department all help to ensure costs remain low where programs overlap and that all sectors whether commercial, residential, low income, new construction or multi-family housing are all served. This IRP reflects these perspectives.

SECTION 5: TRANSMISSION AND DISTRIBUTION SYSTEM

Vermont Gas' pipeline system is an interconnected network of pipelines operating at both transmission and distribution pressures. For ease of reference, pipelines that operate above 100 psi are referenced as the "transmission" system while those operating at or below 100 psi are referenced as the "distribution" system. Together, the transmission and distribution system along with pressure-regulation stations and the propane-air plant ("PAP") comprise Vermont Gas' pipeline network. This section of the plan describes Vermont Gas' planning approach to transmission and distribution system investments and describes the resulting investments in its pipeline system, both to accommodate growth and to ensure safe, reliable delivery of natural gas.

Transmission System

Vermont Gas operates approximately 118 miles of transmission lines. The transmission system interconnects with the TransCanada Pipeline Mainline ("TCPL") at Vermont Gas' border station located in Highgate, Vermont. This point is the sole supply of natural gas for the entirety of the Vermont Gas pipeline system. With the recent completion of the Addison Natural Gas Project, the southern terminus of the transmission system is in Middlebury, Vermont.

The key planning criteria for the transmission system is that it must be designed to ensure reliable delivery of natural gas supplies on a year-round basis and most importantly, on a design-day. As described more fully in the Market Growth and Load Forecast section of this plan, a design day for Vermont Gas is defined as an 86 degree day. For transmission planning purposes, interruptible customers are assumed to be fully curtailed on a design day: the system is sized to meet firm customers' design day demand.

As Vermont Gas' customer base continues to grow and therefore total natural gas usage continues to increase in spite of aggressive energy efficiency efforts, Vermont Gas must periodically expand the design day capability of the transmission system. In recent history, the preferred method has been installing segments of 16-inch transmission-pressure pipeline parallel to the existing 10-inch transmission-pressure pipeline. Vermont Gas refers to this multi-year project as its transmission system "looping". Phase I of the looping project was constructed in

1995 and reinforced the critical Missisquoi River crossing. With the completion of Phase VII in 2016, the 10-inch system is "looped" with 16-inch pipe from the border station to Sandy Birch Rd. in Georgia, Vermont. Looping provided both additional design day capacity as well as the ability to utilize higher pressures from TCPL when available. It also improves system reliability by reducing the length of the single feed portion of the 10-inch line.

As additional capacity is required, Vermont Gas will continue to assess transmission system looping as a means of increasing transmission capacity to accommodate customer growth. Looping has been the most reasonable way to match system capacity to market demand and thereby minimize the rate impact. However, the recent construction of Phase VII and ANGP has shown that pipeline construction costs are steadily rising which may bring the alternatives, discussed later in this section, into contention.

Meeting Design Day Demand

In determining how much transmission expansion is required, Vermont Gas evaluates the design day loads (as described in the Market Growth and Load Forecast Section) to existing system capacity. The capacity of the transmission system is impacted by several factors including the minimum guaranteed pressure from TCPL, the minimum operating pressures required at the south end of the system, and the load patterns on the system. Vermont Gas uses the following key parameters:

- TCPL Minimum Delivery Pressure 580 PSIG
- Minimum Delivery Pressure at Southern Terminus 250 PSIG
- Minimum Delivery Pressure at Winooski Gate Station 225 PSIG
- Minimum Delivery Pressure at North Burlington 100 PSIG
- Maximum Velocity of Gas in Pipeline 60 ft/sec.
- Peak Hour Ratio 5%
- Maximum Propane/Air to NG ratio 30%

Each of these factors is discussed briefly below.

TCPL Minimum Delivery Pressure: The pressure entering the system impacts transmission system capacity. The higher the delivery pressure the more capacity is available. The delivery pressure assumption Vermont Gas uses for transmission planning purposes is equal to the current contractual minimum pressure from TCPL, 580 psig. While frequently higher pressures are available, Vermont Gas only relies on *contractual* minimum pressures for design-day capacity calculations. This is unchanged from prior planning assumptions.

Minimum Southern Pressure: The minimum pressure at the southern terminus of Vermont Gas' system also affects transmission capacity. The lower the acceptable southern terminus pressure, the greater the available capacity. The assumed southern terminus pressure of 250 psig is set at a level to ensure firm customer service can continue uninterrupted. Note: with the recent completion of ANGP, the new physical southern terminus of the transmission system is Middlebury Gate Station. This was mentioned in the prior IRP. Vermont Gas had previously assumed a southern terminus pressure of 225 psig. However, as the system expanded further south, Vermont Gas has increased the acceptable southern pressure to 250. This will allow for better transmission system response and flexibility due to the additional line pack.

Minimum Delivery Pressure at Winooski Gate Station: With the completion of the Addison Natural Gas Project that connects into the existing 10" transmission line north of the Winooski gate and back feeds into the Burlington system via the new Williston gate station, there is less reliance on the Winooski gate to deliver customer demand on a design day. Additionally, because the southern terminus of the transmission system has moved from Winooski Gate Station to Middlebury Gate Station, Winooski no longer needs to remain above 250 psig for reliability. For design purposes, Vermont Gas has reduced the minimum delivery pressure required at Winooski Gate Station to 225 psig. This will allow for more total throughput, as Winooski Gate Station is the largest usage station in the system, while still maintaining the flexibility.

Minimum Delivery Pressure at North Burlington: Vermont Gas relies on the propane air plant to meet a portion of its capacity requirements on a design day. Therefore, the 8" North Burlington lateral between the Propane Air Plant ("PAP") and the Convent Square gate station has to have adequate pressure to enable deliveries of propane/air to the North Burlington/Colchester area. Monitoring these pressures will ensure the PAP can be utilized to its potential. This planning parameter remains unchanged from the prior IRP.

Maximum Velocity: The velocity of the natural gas is set at a maximum of 60 feet per second. Higher velocities result in unnecessary wear and tear on measurement and control equipment, which in turn results in increased maintenance and repair costs. This planning parameter is consistent with industry standard and unchanged from the prior IRP.

Peak-Hour Ratio: Peak-hour ratio (i.e. the peak hour load as a percent of the daily load) affects the capacity of the transmission system: the higher the peak-hour ratio, the lower the capacity on the transmission system. For purposes of this plan, a 5% peak-hour ratio was used. This is consistent with industry standards and is unchanged from the prior IRP.

Propane-Air to Natural Gas Ratio: During peak-periods, Vermont Gas injects a mixture of propane and air into its transmission system to both supplement the natural gas supply and increase the available capacity on the transmission system. The higher the ratio of propane-air to natural gas, the greater the available capacity on the transmission system. However, if the ratio of propane-air is too high, there can be an adverse impact on the functioning of customer's natural gas appliances. Consistent with past planning assumptions, for purposes of this plan, Vermont Gas has used a 30% ratio. Experience indicates that at higher levels operational difficulties down-stream of the propane-air plan may occur.

In addition to the factors listed above, the send-out pattern (i.e. where on the Vermont Gas system the load occurs) impacts the transmission capacity. Load located at the northern end of the system has less of an impact on system capacity than load located at the southern end due to the additional capacity of the 16-inch looping. The send-out percentages used in the calculations are shown in Table 5.1 and are based on actual, historical, take-off patterns.

Table 5.1

Gate Station	Flow as a Percent of Total System Flow (%)
Carter Hill Road, Highgate	0.02%
Route 78, Swanton	2.18%
Sheldon Town	0.80%
Lower Newton Road, St. Albans	0.22%
Lake Street, St. Albans	5.59%
Nason Road, St. Albans	4.27%
Georgia Plains Road, Georgia	0.18%
Sandy Birch Road, Georgia	0.83%
Murray Road, Milton	0.02%
Christine Court, Milton	0.21%
Quail Hollow, Milton	0.23%
Milton (Route 7)	2.40%
Catamount Industrial Park, Milton	0.68%
Middle Road, Colchester	4.98%
Sunderland Station, Colchester	8.15%
Malletts Bay Avenue, Colchester	1.48%
Convent Square, Burlington	18.20%
Winooski (Gorge Road)	35.24%
Williston (Route 2)	10.78%
Plank Road, New Haven	1.73%
Middlebury (Route 7)	1.81%

With the addition of Phase VII Looping and the three new gate stations (Williston, Plank Road, and Middlebury) applying the above assumptions to Vermont Gas' network-analysis software, GL Nobel Denton, Inc. SynerGEE Gas Version 4.5.2, yields a current pipeline capacity of 69,808 Mcfd. When combined with output of the propane-air plant (7,730 Mcfd), the total system capacity is 77,538 Mcfd for the 2017/2018 winter.

As can be seen in Table 5.2, based on the base competitive position design day forecast, which includes energy efficiency, the recent completion of Phase VII Looping has given Vermont Gas reasonable reserve capacity for the next several winter seasons. It should be noted that for system capacity planning purposes, Vermont Gas uses the high-end of the design-day forecast band.

Table 5.2

Winter Season	Estimated Peak-Day Send Out	Estimate Pipeline Capacity	Estimated Propane/Air Capacity	Total System Capacity	Estimated System Capacity Excess/(Shortfall)
2018	74,467	69,808	7,730	77,538	3,071
2019	75,228	69,808	7,730	77,538	2,310
2020	75,913	69,808	7,730	77,538	1,625
2021	76,425	69,808	7,730	77,538	1,113
2022	76,929	69,808	7,730	77,538	609

In the prior IRP, Vermont Gas discussed at length its planning around the service agreement they had entered with International Paper (IP) to extend natural gas service to its paper mill located in Ticonderoga, New York. Since then that service agreement has been terminated and IP is receiving compressed natural gas delivered by truck in lieu of pipeline gas. This means Vermont Gas is no longer including service to IP in the planning process. Also in the prior IRP, it was assumed that Phase VII Looping would be 6.5 miles long. This was, in part, to limit the amount of days IP would be curtailed as part of their interruptible service. A review of Vermont Gas' capacity needs indicated 3 miles would suffice and accordingly Phase VII was constructed as a 3 mile section of 16-inch transmission loop running from Reynolds Road in Georgia, the terminus of Phase VI, to the existing VGS gate station at Sandy Birch Road in Georgia.

As Vermont Gas stands right now, there is enough capacity in the transmission system to accommodate high case growth for the next 5+ years. As demand continues to increase in the coming years, VGS will evaluate all options to expand the amount of gas they can supply. For consistency with past IRPs, 16-inch transmission looping will be discussed first, followed by alternatives.

Phased transmission looping continues to be the desired method of transmission capacity expansion based on economics and reliability. By phasing the transmission system expansion, Vermont Gas is able to reasonably match system capacity to market demand and thereby minimize the rate impact associated with expanding the transmission system. Vermont Gas believes this phased approach is very practical for natural gas pipeline expansion. The starting point of each expansion is pre-determined: they will begin from the end-point of the existing looped facilities. Further, unless environmental, land use or reliability concerns necessitate deviating, the corridor for each pipeline segment is in or adjacent to the same right of way. This is consistent with federal, state and regional policy favoring the use of existing corridors to the greatest extent possible.

In determining how long each phase of looping should be Vermont Gas looks at how much additional capacity is expected to be required over the next few years and where are there logical interconnection points along its system, i.e. existing valves or gate stations. As long as Vermont Gas has pre-identified the corridor, this approach provides a reasonable blend of flexibility and reliability.

Based on current planning, Phase-VIII Looping would consist of 3.5 miles of 16-inch transmission main running from Sandy Birch Road in Georgia, the terminus of Phase VII, to Poor Farm Road in Milton. This is consistent with the originally planned Phase VII end point before it was shortened.

Table 5.3 shows what the added capacity would be once Phase VIII (or a similar sized alternative) is operational.

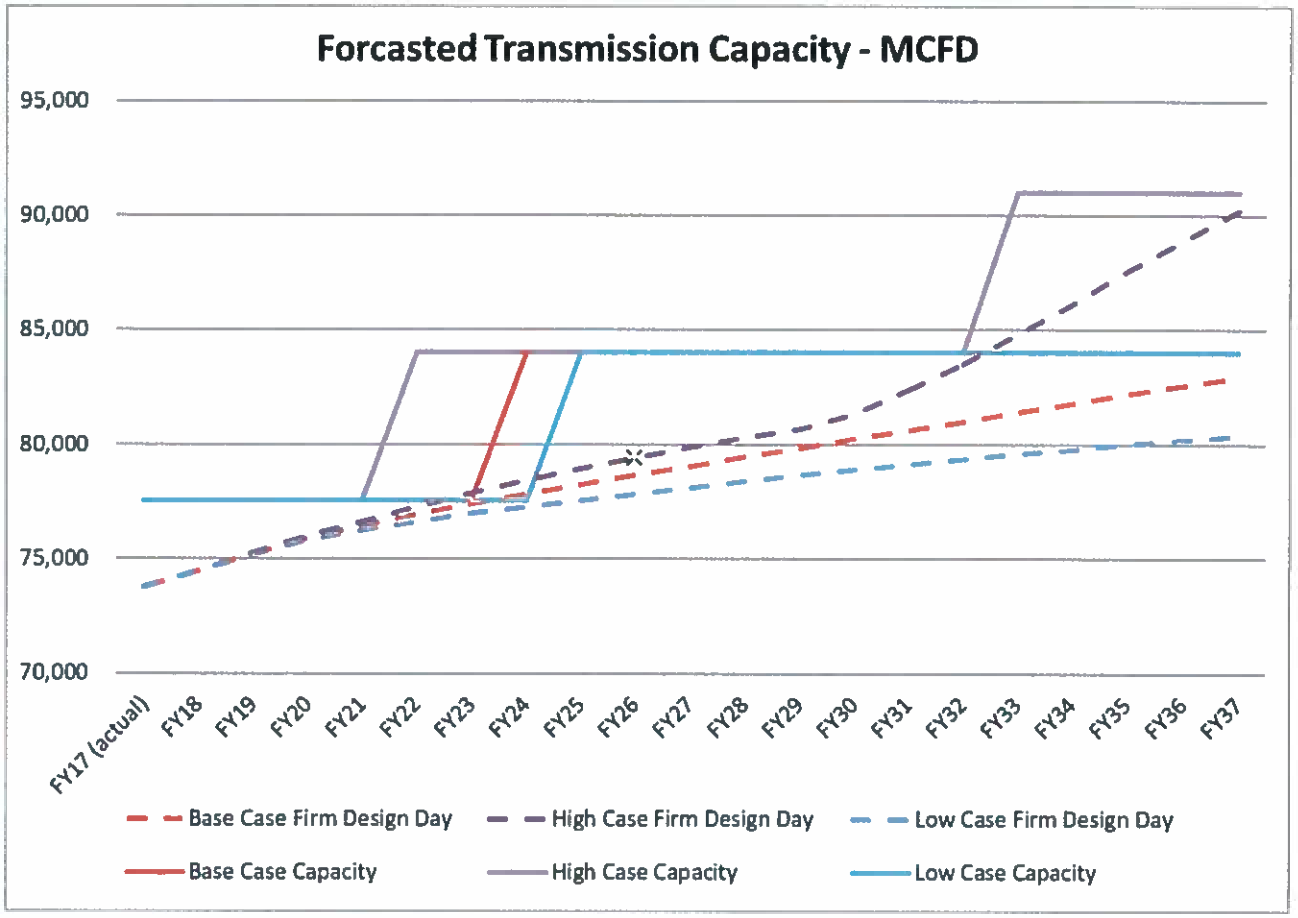
Table 5.3

Phase	Miles	Pipeline Capacity (Mcfd)	Propane Air (Mcfd)	Phase VIII Capacity (mcfd)	Total Capacity (Mcfd)
VIII	3.5	69,808	7,730	6,480	84,018

Note: Capacities subject to change depending on location of growth.

Based on the gas demands described in the Market Growth and Load Forecast section of this plan, the following chart (5.1) details the timing of the subsequent phases of the transmission system expansion under base, low and high competitive position scenarios. Please note that construction of transmission system expansion is assumed to occur the summer before the winter that it is needed, i.e., if the shortfall is expected to occur in the winter of FY 2021, then construction would occur in the summer of FY 2020.

Chart 5.1



Before deciding to expand its transmission system, Vermont Gas will also consider several other capacity-related options. The appropriateness of any of these alternatives instead of 16-inch transmission main looping would be developed more fully in the applicable 248 proceeding. Potential alternatives are described below.

Looping with Different Diameter Pipe: While all prior phases of looping were constructed using 16-inch diameter pipe, it is appropriate to continue to evaluate whether 16-inch is the proper size pipe for subsequent phases. In analyzing previous phases of looping, Vermont Gas has evaluated whether a smaller diameter pipe was least cost. Although the 16-inch is more expensive than smaller diameter, it provides more flexibility for continued growth south of the existing service footprint. Similar analyses will be undertaken for subsequent phases.

Increase Maximum Operating Pressure to 660 psi: This would entail negotiating with TransCanada Pipelines to increase the minimum contractual delivery pressure from 580 psi to 660 psi. While this option may be viable at some point in time, it is not operationally preferred. TCPL operates a single-feed line into Vermont. Vermont Gas' objective is to increase the reliability on that line by the installation of additional pipe north of the border. While TCPL looped a segment of this single-feed line in 2008, there still remains approximately 13 kilometers of single-feed line to the Vermont border. If TCPL were to increase the capacity by increasing pressure, no additional reliability would be gained and TCPL would have no need to continue its looping. After TCPL fully loops its system, it may then be appropriate to consider a pressure uprate. TCPL is currently in the process of permitting a 4 kilometer looping project to reduce the amount of un-looped line feeding Vermont and thus increasing reliability to the border.

Compression on the 16-inch line: This is similar to the alternative discussed above except that only pressures in the 16-inch line would be raised. While any potential concerns about the 10-inch line are ameliorated under this scenario, the concerns with the TransCanada line still exist. Therefore, based on current planning assumptions this option is not preferred, but would be considered before committing to an alternate strategy.

Expansion of the propane air plant (PAP): Currently the propane air plant is a critical resource on design day. To increase the output and capacity of the propane air plant, not only would additional compressors need to be installed, but also additional system upgrades would be needed to alleviate pressure drops. Vermont Gas could increase the capacity of the PAP by increasing the ratio of propane/air to natural gas. This can result in downstream performance problems with high efficiency equipment and will therefore not be considered in future analyses. Additionally, expansion of the propane air plant without a corresponding expansion in pipeline would leave Vermont Gas vulnerable to any mechanical failures at the propane air plant. Based on current planning assumptions, expansion of the PAP is unlikely to be an appropriate alternative for transmission system expansion or other alternatives.

Construction of a Liquefied Natural Gas (LNG) Facility: Vermont Gas has explored at a high level the utilization of LNG for peak shaving. A peaking facility consisted of the following infrastructure and operation capabilities:

- 120,000 gallon LNG storage tanks
- 5,400 MCF of daily vaporization (water bath)
- 6 acre parcel
- Trucking to support 7 consecutive days of operation

As the technology advances, the costs of installing an LNG peak shaving plant could become more comparable to pipeline construction. The LNG option would also introduce a supply source other than natural gas supplies via TCPL. In 2012, when the prior IRP was filed, LNG could only be sourced from a single supplier, Gaz Suez, at the Distrigas terminal in Everett, MA. Since then, alternate sources of LNG have developed, which is discussed further in the Supply section of this plan.

Having a second source of gas potentially located on the southern end of the transmission system also improves reliability. Although the output is not extremely high, the LNG plant could back feed the system in the event of a break on the transmission line.

Compressed Natural Gas (CNG), Trucked or Stored: Vermont Gas operated a trucked CNG "gas island" in Middlebury, VT while awaiting for the completion of ANGP. Although, depending on location, it is less cost effective to operate than a pipeline system on a permanent basis, it could be feasible as a peak shaving resource. The downside to trucked CNG is that each truck only has a small capacity, therefore many trucks and a large parcel of land would be needed if this was the sole capacity expansion project for firm customers for the future.

Distribution System

As of December 31, 2016, Vermont Gas had 813 miles of distribution mains and 38,911 services. In this section, the additional investment in distribution mains, services and meters necessary in response to customers demand to serve the projected customer growth are reviewed.

Distribution system planning is driven by the projected number of customers. The investment in distribution main, services, and meters is determined based on the projected number of customers and historical averages for footage per customer and the percent of customers requiring mains and services. These footages are then applied to current cost per foot and escalated with an inflator each year. The actual cost for any given main extension may vary depending on the construction conditions encountered and the actual footage required.

Other System Investments

In addition to the growth-related investments described above, Vermont Gas does planning and assessment related to ensuring the on-going safe operation of its pipeline network. This includes, but is not limited to, the following:

- Periodic review of system flow analysis to identify areas of the distribution network that may require reinforcement;
- Risk-based assessments of the transmission and distribution system pursuant to federally mandated transmission and distribution system integrity management programs;
- On-going leak detection initiatives;
- Review of gate station conditions; and
- Review of meter testing results.

A brief description of some of the results of these planning initiatives is described below:

Distribution Reinforcement: As with the transmission system, the distribution system network is analyzed through the use of Vermont Gas' network-analysis software, GL Nobel Denton, Inc. SynerGEE Gas Version 4.5.2. The system is modeled annually with the addition of new loads on the distribution system. Over the past few years, Vermont Gas has completed distribution reinforcement projects to bolster the system capabilities and reliability. These include connecting Dorset Street and Spear Street via Barstow Road in Shelburne with 6-inch main, completing a 4-inch loop on Marshall Avenue in Williston and crossing I-89 with 4-inch main on Bay Road in Colchester. These projects all aided in raising the overall end pressures in the Burlington distribution system allowing for increased capacity. This work that was completed over the last several years has yielded a fairly strong system that will carry into the future. Presently the greater Burlington area is not in need of any distribution pipeline reinforcements. Should an area within the system experience exceptional growth, then Vermont Gas would install distribution reinforcements. One of the most beneficial additions to the system for future reliability has been from the facilities installed associated with the ANGP. The Williston Gate Station, located on Route 2 in Williston, provides a back feed into the Burlington area boosting the pressures throughout the system. This has increased the deliverability of the entire Burlington distribution system, as well as adding flexibility in how the system is operated.

Gate & Industrial Station Improvements: Many of the existing gate and industrial stations in the system will need upgrading. Crucial components in some of these stations are over 30 years old. The new technology available will provide better information, enhanced flexibility and improved safety/security. Vermont Gas plans to upgrade several gate and industrial measurement stations during the first five years of this plan. These gate station improvement projects do not increase system capacity, but ensure Vermont Gas is able to reliably serve its customers. Vermont Gas anticipates that its gate stations and industrial meter stations will continue to need upgrading as the facilities age. Some of the criteria that is reviewed in deciding whether a station needs attention are: obsolete equipment, physical condition of the piping, equipment capacity, maintenance history, and overall safety of the system and personnel working on the equipment. Currently stations are expected to be upgraded over the next 5 years include:

Beebe Road Gate Station: A new station at Beebe Rd will allow for the removal of the Swanton Gate Station (built 1965) and the Bushey Street Gate Station (built 1992). In addition to reduced maintenance expense from eliminating two aging gate stations, the removal of these two stations will also make it easier to complete the hydrostatic test on the 10" transmission line in an HCA area of the pipeline. The main line valve will stay at the current location at the Swanton gate but the regulating station could be removed from the center of town.

Milton Gate Station: This station was built in 1965. The station design is old and does not have a station heater or building to protect the equipment from the elements. The new station design will include a new configuration that would safety and ease of maintenance.

Additionally, an alternative to upgrading the Milton Gate Station would be to run distribution pipe from the Sandy Birch Station area to the Milton Station area. Sandy Birch was rebuilt in 2016 and can easily maintain pressures in the Milton system after distribution main is run under the Lamoille River near the Georgia high bridge and tied into the gas main on North Road. This would also replace the need to create a small bypass station at Milton station during a rebuild.

If the distribution systems could be connected between the Sandy Birch Gate Station, the Milton Gate Station and the Catamount Gate Station, then the Milton Gate Station could be retired and the Catamount station rebuilt.

Catamount Gate Station - The station was built in 1984. The station could use an upgrade to at least a 2" Fisher 627 regulator to handle the increased load. In the future, the Catamount station could be connected to the Milton station area to help as a backup and redundancy for the two gas systems. If the connection were made between the two systems, a larger station at Catamount station would be preferred to be able to handle the entire load of the two areas.

Mallets Bay Ave Gate Station: The station was built in 1990 with 2" Axial Flow regulators that require taking the valve out of the piping system to replace the rubber boot. These older style regulators take longer to remove and reinstall. The station needs a heater and building to protect the regulators from the elements and to help reduce noise from the station. Power and communications could also be installed to monitor station conditions on flow and inlet and outlet pressures. Currently, there are wireless communications only on the instrument showing flows, however, this could be expanded for the entire station. A new tap and valve would be an added safety item by having a shutdown valve at least 25 feet away from the station.

Route 78 Gate Station: This station could use a building over the station to reduce noise and protect the station from the elements. The station heater will need to be moved further away from the station to install a building. The communication equipment also needs to be moved further away from the station equipment into a separate building.

Sheldon/Rock Tenn Gate Station: This station could also use a building placed over the new station sometime in the future.

Farm Tap Stations: Combine small station areas if possible and in the future start replacing the farm tap station so that a meter can be placed in the station for gas measurement.

Meter Replacement: Through the meter testing process, Vermont Gas has identified several classes of meters to be replaced. As a result of several year's implementation of the testing program, Vermont Gas has determined that it is appropriate to proactively begin replacing meters when they have been in the field for 25 years. This IRP assumes the continuation of this practice.

SECTION 6: FINANCIAL IMPACTS

METHODOLOGY

The financial analysis developed in this IRP serves as a means to compare the financial implications of the three scenarios from a cost of service perspective as well as provide other key financial metrics. The financial analysis does not support a current or future rate filing and furthermore does not reflect the level of detail that would be necessary to support a rate filing.

For each scenario, assumptions have been made to derive average rate base, gas costs, operating expenses, capital expenditures, and total other expenses, as well as financial and authorized return. The derivation of each of these components is discussed below.

ASSUMPTIONS

Rate Base: Rate base is calculated using a 13-month average.

Capital Investments; Capital investments included within the financial analysis reflect the estimated investment in transmission, distribution, mains and other pipeline infrastructure as described previously within the T&D Section of this plan. Investments in other capital items, such as general plant and rental property are held constant through the various scenarios. Additional system investments are added to Vermont Gas' projected plant in-service projected as of September 30, 2017.

Demand Side Management ("DSM") Balances: As the Company is currently operating as an Energy Efficiency Utility ("EEU"), we are no longer accumulating deferred balances related to energy efficiency spending on the Company's balance sheet. As an EEU energy efficiency is funded through a "pay as you go" model via an energy efficiency charge on customers' bills. Pre-EEU, a significant portion of energy efficiency investments were deferred to balance sheet accounts for future recovery. Each scenario modeled the amortization of these "legacy" DSM buckets, with no further energy efficiency-related deferrals. Refer to "Amortization Expense" below for further detail.

Depreciation Expense: Depreciation expense is based upon projected plant-in service as of September 30, 2017 plus projected capital expenditures. The related depreciation rates, by plant type are consistent with the Company's current Depreciation Study.

Accumulated Depreciation: Accumulated Depreciation is increased annually by the annual depreciation associated with plant in-service.

Purchased Gas Costs. The purchased gas adjustment for each scenario is determined from the gas costs and revenue models described in the Supply-Side Planning section.

Responsibility Expenses: Responsibility expenses, including salaries and benefits are based on the forecasted twelve months ending September 30, 2017. While the Company is committed to controlling its expenses, for the purpose of this high-level modelling, operating expenses are escalated at a 2% inflation rate with no explicit cost-containment initiatives modeled.

Amortization Expense: Amortization expense is based upon the following and is consistent with current practice:

- The legacy DSM buckets assume a 10-year amortization period,
- The Barge Canal balance currently being amortized, assuming a 20 year amortization period
- The amortization of the Addison Natural Gas Project first 11 mile regulatory asset, assuming a 10 year amortization period.

Taxes Other Than Income: Taxes other than income assumes a property tax rate of approximately 2.0% per year plus gross receipts and weatherization taxes at 0.3% and 0.75% respectively, consistent with current rates.

Interest Expense: Interest expense is broken into long-term and short-term. Long-term interest expense is based on Vermont Gas' current long-term debt ("LTD") structure, adjusted for any maturities. The significant capital expenditures modeled in the "high case" scenario required the issuance of additional LTD. The scenario assumes sufficient incremental LTD to maintain a 50% debt to equity capital structure, consistent with the Company's current capital structure (refer to "Capital Structure" below for more detail). VGS assumed a LTD interest rate of 4.00%

as this is relatively consistent with the Company's last debt issuance. Vermont Gas recognizes that current capital markets will likely vary from this estimate; however, for purposes of this analysis a rate of 4.00% was utilized.

Short-term interest is assumed to be approximately 2.0%. Short-term interest is based upon the 30-day LIBOR rate plus approximately 105 basis points, which is the average credit spread under the Company's existing short-term debt structure. For purposes of this analysis, Vermont Gas made the assumption to keep LIBOR relatively consistent as the change will not materially impact the financial analysis. Vermont Gas further notes that in each scenario there is the potential opportunity to reduce short-term debt with additional long-term debt financing; however, for purposes of this analysis long-term debt financing was not assumed as this would not material impact interest expense or the reader's interpretation of the scenarios.

Return on Equity. Vermont Gas has performed a sensitivity analysis surrounding Return on Equity ("ROE"). The Company has modeled all three scenarios (Base, Low & High) with an upper and a lower ROE range. The Company utilized an ROE of 9.0% for the lower range and 9.7% for the upper range.

Capital Structure. The financial scenarios were projected assuming Vermont Gas's currently authorized equity ratio of 50%.

System Expansion & Reliability Fund (SERF). The three scenarios reflect SERF collections based on MCF sales per the load forecast in the Supply section of this plan. As SERF is collected, Vermont Gas reflects the SERF collections as a regulatory liability as the monies associated with the SERF are utilized in a future period to offset rate impacts. Each of the scenarios reflects the continuation of SERF collections through 2021, consistent with the MOU adopted in Docket 8710. Further, SERF withdrawals are fully utilized by the end of 2021 in all scenarios, which is also consistent with the MOU adopted in Docket 8710. The withdrawals have been utilized as a mechanism to smooth rates through 2021.

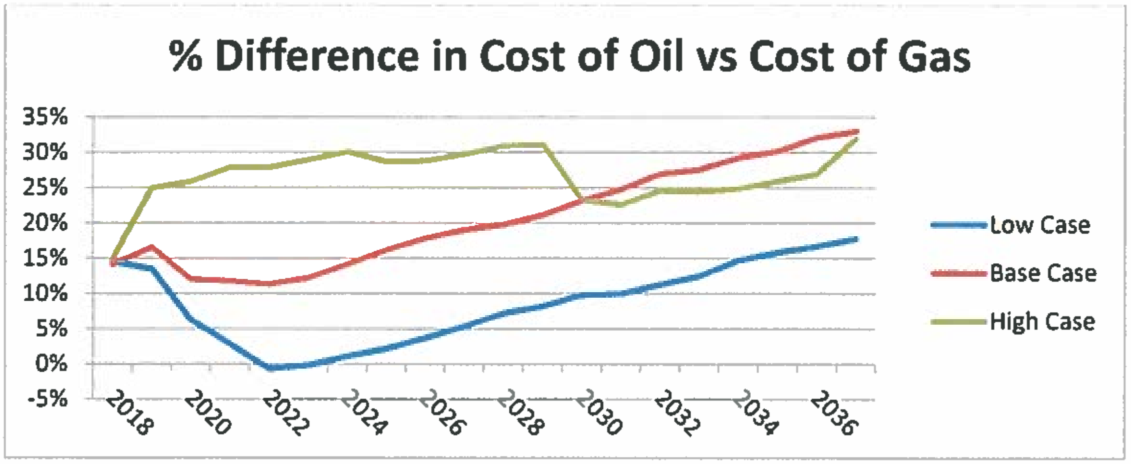
RESULTS

The financial analysis was run for the three scenarios discussed within this Plan. The financial analysis helps inform planning decisions by striking a balance of key objectives, including maintaining stable and competitive rates, striving to have a reasonable opportunity to achieve the allowed return on equity, and giving consideration of advancing state energy policy.

Under our tariff, base rates are intended to cover the non-gas components of the Company's operations. In all scenarios within this plan, there are moderate base rate increases through 2022 and SERF utilization through 2021. After 2022, when the Company has gradually brought base rates to a level in which they cover the cost of ANGP being in service, there are little to no base rate changes projected in the scenarios. The exception to this is in the high case scenario which assumes as a "what if" planning scenario a natural gas expansion to Rutland County provided that such there is substantial customer demand resulting from a significant price advantage over heating oil and strong public policy and community support. In that scenario, the base rate changes are more measurable. As modeled, the high case scenario financial analysis assumed the cost of a hypothetical Rutland expansion would be covered with increased base rates. The Company is not pursuing such an expansion at this time. However, should such an expansion occur, the Company would explore means to mitigate rate impacts for existing customers.

In each of the three scenarios, Vermont Gas maintains a favorable competitive position against oil, which is consistent with the analysis presented in the Market Growth section of the plan. In the graph presented below, which presents the percentage difference in the cost of oil over the cost of gas, this is demonstrated. In the high case scenario, which includes base rate increases related to the hypothetical significant expansion, the competitive position is still advantageous against oil; however the competitive position decreases in the year in which the expansion occurs. As noted above, this, along with all scenarios, are simplified modeling assumptions. Vermont Gas would evaluate means to cover the cost of such an expansion without undue rate pressure for existing customers.

Figure 6.1 Percentage Difference in Competitive Position



Additional information regarding the output of the scenarios is provided in the following attachments:

High Competitive Position:	Attachment 6.1
Base Case Competitive Position:	Attachment 6.2
Low Competitive Position:	Attachment 6.3

VGS Financial Analysis

	2018	2023	2028	2032	2037
Average Number of Customers	51,700	55,800	59,100	62,400	69,700
Firm Gas Sales Mcf	6,800,000	7,000,000	7,200,000	7,400,000	7,900,000
Interruptible Gas Sales Mcf	5,700,000	5,800,000	5,800,000	5,800,000	5,800,000
Total Mcf Sales	12,500,000	12,800,000	13,000,000	13,200,000	13,700,000
Firm Gas Revenue	35,800,000	47,200,000	63,100,000	78,900,000	81,800,000
Firm Base Revenue	48,300,000	64,700,000	67,800,000	90,100,000	99,000,000
SERF	6,900,000	-	-	-	-
Total Firm Revenue	91,000,000	111,900,000	130,900,000	169,000,000	180,800,000
Interruptible Revenue	28,000,000	39,900,000	51,500,000	64,100,000	70,900,000
Rental & Other Revenue	3,600,000	4,000,000	4,200,000	4,400,000	4,600,000
Total Revenue	122,600,000	155,800,000	186,600,000	237,500,000	256,300,000
Cost of Gas	63,600,000	86,700,000	114,500,000	142,900,000	152,600,000
Responsibility Expenses	17,600,000	19,500,000	21,500,000	23,200,000	25,700,000
Depreciation	10,700,000	13,400,000	15,600,000	19,900,000	23,600,000
DSM and Regulatory Amortization	1,700,000	500,000	-	-	-
Taxes Other Than Income	6,200,000	9,400,000	10,800,000	15,500,000	17,800,000
Interest Expense	6,800,000	6,300,000	5,700,000	6,000,000	5,600,000
Income Taxes*	6,400,000	8,100,000	7,500,000	12,100,000	12,500,000
Return at 9.7%	9,500,000	11,900,000	11,000,000	17,800,000	18,400,000
Return at 9.0%	9,500,000	11,000,000	10,200,000	16,500,000	17,000,000
Total Non-Gas Cost of Service at 9.7% Return	58,900,000	69,100,000	72,100,000	94,500,000	103,600,000
Total Non-Gas Cost of Service at 9.0% Return	58,900,000	68,200,000	71,300,000	93,200,000	102,200,000
Total Cost of Service at 9.7% Return*	122,500,000	155,800,000	186,600,000	237,400,000	256,200,000
Total Cost of Service at 9.0% Return	122,500,000	154,900,000	185,800,000	236,100,000	254,800,000
Capital Expenditures	16,300,000	10,900,000	10,500,000	17,800,000	19,800,000
Average Rate Base	255,000,000	245,100,000	227,800,000	367,300,000	379,500,000
Short & Long Term Debt	141,900,000	128,200,000	117,600,000	189,800,000	195,700,000
Stockholders Equity	145,600,000	125,600,000	114,600,000	179,100,000	184,400,000
SERF Collections	(5,100,000)	-	-	-	-
SERF Withdrawals	12,000,000	-	-	-	-
Balance as of September	17,700,000	-	-	-	-

*Income Taxes represent the 9.7% return scenario. Should the return be 9.0%, Income Taxes would be adjusted

* The return does not vary in year 2018 as the scenario assumes the Company will not earn their allowed return

VGS Financial Analysis

	2018	2023	2028	2032	2037
Average Number of Customers	51,700	55,400	58,200	60,100	62,500
Firm Gas Sales Mcf	6,800,000	7,000,000	7,100,000	7,200,000	7,200,000
Interruptible Gas Sales Mcf	5,700,000	5,800,000	5,800,000	5,800,000	5,800,000
Total Mcf Sales	12,500,000	12,800,000	12,900,000	13,000,000	13,000,000
Firm Gas Revenue	36,500,000	46,600,000	56,700,000	64,000,000	68,200,000
Firm Base Revenue	48,300,000	64,400,000	67,800,000	69,600,000	71,900,000
SERF	6,900,000	0	0	0	0
Total Firm Revenue	91,700,000	111,000,000	124,500,000	133,600,000	140,100,000
Interruptible Revenue	29,400,000	39,200,000	47,400,000	53,000,000	57,100,000
Rental & Other Revenue	3,600,000	4,000,000	4,200,000	4,400,000	4,600,000
Total Revenue	124,700,000	154,200,000	176,100,000	191,000,000	201,800,000
Cost of Gas	65,900,000	85,400,000	104,000,000	116,900,000	125,200,000
Responsibility Expenses	17,600,000	19,500,000	21,500,000	23,200,000	25,700,000
Depreciation	10,700,000	13,200,000	15,400,000	17,200,000	19,500,000
DSM and Regulatory Amortization	1,700,000	500,000	0	0	0
Taxes Other Than Income	6,200,000	9,200,000	10,700,000	11,700,000	12,900,000
Interest Expense	6,800,000	6,400,000	5,800,000	5,000,000	4,300,000
Income Taxes*	6,400,000	8,100,000	7,600,000	6,900,000	5,800,000
Return at 9.7%	9,400,000	12,000,000	11,100,000	10,100,000	8,500,000
Return at 9.0%	9,400,000	11,000,000	10,300,000	9,300,000	7,800,000
Total Non-Gas Cost of Service at 9.7% Return	58,800,000	68,900,000	72,100,000	74,100,000	76,700,000
Total Non-Gas Cost of Service at 9.0% Return	58,800,000	67,900,000	71,300,000	73,300,000	76,000,000
Total Cost of Service at 9.7% Return*	124,700,000	154,300,000	176,100,000	191,000,000	201,900,000
Total Cost of Service at 9.0% Return	124,700,000	153,300,000	175,300,000	190,200,000	201,200,000
Capital Expenditures	16,300,000	13,600,000	10,400,000	11,100,000	12,100,000
Average Rate Base	255,300,000	245,900,000	228,500,000	207,400,000	174,100,000
Short & Long Term Debt	142,600,000	129,200,000	118,700,000	106,800,000	89,600,000
Stockholders Equity	145,500,000	125,400,000	113,600,000	101,500,000	84,100,000
SERF Collections	5,100,000	0	0	0	0
SERF Withdrawals	12,000,000	0	0	0	0
Balance as of September	17,700,000	0	0	0	0

*Income Taxes represent the 9.7% return scenario. Should the return be 9.0%, Income Taxes would be adjusted

* The return does not vary in year 2018 as the scenario assumes the Company will not earn their allowed return

VGS Financial Analysis

	2018	2023	2028	2032	2037
Average Number of Customers	51,700	54,900	57,200	58,800	60,900
Firm Gas Sales Mcf	6,800,000	6,900,000	7,000,000	7,100,000	7,100,000
Interruptible Gas Sales Mcf	5,700,000	5,800,000	5,800,000	5,800,000	5,800,000
Total Mcf Sales	12,500,000	12,700,000	12,800,000	12,900,000	12,900,000
Firm Gas Revenue	36,000,000	43,100,000	52,600,000	61,700,000	66,600,000
Firm Base Revenue	48,300,000	62,800,000	66,700,000	68,500,000	70,900,000
SERF	6,900,000	-	-	-	-
Total Firm Revenue	91,200,000	105,900,000	119,300,000	130,200,000	137,500,000
Interruptible Revenue	28,300,000	36,500,000	44,400,000	51,800,000	56,400,000
Rental & Other Revenue	3,600,000	4,000,000	4,200,000	4,400,000	4,600,000
Total Revenue	123,100,000	146,400,000	167,900,000	186,400,000	198,500,000
Cost of Gas	64,200,000	79,300,000	96,900,000	113,400,000	122,900,000
Responsibility Expenses	17,600,000	19,500,000	21,500,000	23,200,000	25,700,000
Depreciation	10,700,000	13,100,000	15,200,000	16,900,000	19,200,000
DSM and Regulatory Amortization	1,700,000	500,000	-	-	-
Taxes Other Than Income	6,200,000	9,100,000	10,300,000	11,300,000	12,500,000
Interest Expense	6,800,000	6,200,000	5,600,000	5,000,000	4,400,000
Income Taxes*	6,400,000	7,700,000	7,500,000	6,700,000	5,600,000
Return at 9.7%	9,500,000	11,200,000	11,000,000	9,800,000	8,300,000
Return at 9.0%	9,500,000	10,400,000	10,100,000	9,100,000	7,700,000
Total Non-Gas Cost of Service at 9.7% Return	58,900,000	67,300,000	71,100,000	72,900,000	75,700,000
Total Non-Gas Cost of Service at 9.0% Return	58,900,000	66,500,000	70,200,000	72,200,000	75,100,000
Total Cost of Service at 9.7% Return*	123,100,000	146,600,000	168,000,000	186,300,000	198,600,000
Total Cost of Service at 9.0% Return	123,100,000	145,800,000	167,100,000	185,600,000	198,000,000
Capital Expenditures	16,300,000	10,100,000	10,100,000	10,900,000	11,900,000
Average Rate Base	255,100,000	231,200,000	225,200,000	203,500,000	170,800,000
Short & Long Term Debt	142,100,000	121,800,000	117,900,000	106,200,000	89,600,000
Stockholders Equity	145,600,000	118,300,000	113,200,000	101,200,000	83,900,000
SERF Collections	12,000,000	-	-	-	-
SERF Withdrawals	(5,100,000)	-	-	-	-
Balance as of September	17,700,000	-	-	-	-

*Income Taxes represent the 9.7% return scenario. Should the return be 9.0%, Income Taxes would be adjusted

Note: The return does not vary in year 2018 as the scenario assumes the Company will not earn their allowed return

SECTION 7: IMPLEMENTATION

This section reviews the implementation plans that are derived from the outcomes of the scenarios and the analysis discussed in this IRP.

Planning is a dynamic process, and thus the strategies discussed in this IRP will evolve over time based on the environmental and operating considerations. This includes the Company's approach to market expansion, energy efficiency and system planning, expanding into new areas when the competitive position is strong, and boosting energy efficiency initiatives when market conditions dictate.

Marketing:

- Expand natural gas service into new communities, including those that the Company agreed to in Docket 7970 (Middlebury[1], East Middlebury, Vergennes[1], New Haven, Bristol, St. George and Monkton).
- Continue to offer the choice of natural gas service within the current footprint through oil-to-gas conversions, cost-effective expansion into new streets and neighborhoods and provide the option of natural gas service to residential new construction customers.
- Continue to evaluate and seek opportunities in non-traditional market areas, including: bulk compression and delivery of Compressed Natural Gas (CNG); installation of Gas Islands; electric generation; heat pumps; and NGVs.
- Long term, periodically review and evaluate possible expansion further south if consistent with state energy policy and cost effective. The Company does not anticipate any such expansion absent a state energy plan that supports such expansion, the support of the communities impacted, strong regulatory and policymakers' support, and a means to fund the expansion without undue rate pressure on existing customers.

[1] Expansion into Middlebury & Vergennes have begun in 2017.

Supply Side Planning:

- Integrate into the supply portfolio 10,000 GJ of contracted capacity.
- Continue to seek full utilization of capacity resources through asset management agreements on any unused capacity.
- Continue to use a competitive bid process for annual baseload supply purchases and asset management agreements, while using short and medium-term supply contracts to maintain flexibility.
- Expand service offerings to include Renewable Natural Gas (RNG), working with RNG suppliers and customers to implement the Company's proposed RNG program, which is pending approval by the Public Utilities Commission.
- Continue the ongoing hedging program to minimize price volatility and maintain stable rates for its customers.

Energy Efficiency:

- Complete the first Demand Resource Plan ("DRP") for years 2018-2020, which will establish budgets and savings goals for those years, while identifying indicative savings and budgets through 2037. Follow the guidelines outlined in said DRP plan.
- Achieve 30% participation in energy efficiency programs in Addison County. Continue to aggressively market efficiency programs in the new communities.

Transmission and Distribution:

- Design, construct and operate the pipeline system in response to evolving market demands.
- Continue to meet the requirements of the meter replacement and testing program.
- Continue to monitor and remediate the transmission and distribution systems for safety- and reliability-related concerns, such as leaks, corrosion or other abnormal operating conditions.
- Modernize and upgrade several gate stations to enhance system reliability.

Finance:

- Continue focus on cost control to ensure stable and affordable rates for customers.
- Continue to monitor and address financial and rate impacts resulting from the completion of ANGP and the utilization of the System Expansion and Reliability Fund ("SERF"). As a result of Docket 8710, the collection of SERF will be discontinued after 2021.