Alaska Natural Gas In-State Demand Study
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Volume 1: Technical Report

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Executive Summary

The purpose of this report is to examine the future natural gas demand of Alaska communities and businesses. The study was prepared in a manner that provides quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. The major results of our study can be summarized as follows.

- We developed a baseline forecast which assumes a business as usual environment over the forecast period. Alaska prices were assumed to be constant, in real dollars, over the forecast period, while income was assumed to be increasing at a real annual average rate of a half-percent per year. (Chapter 4, page 25)

- Baseline residential natural gas demand is expected to grow at an average rate of 1.8 percent per year to 2020. Over the next ten years, residential baseline demand will increase by 3.5 Bcf per year, and will increase by 7.9 Bcf by 2020. (Chapter 4, Table 4.1)

- Baseline commercial natural gas demand is expected to grow at an annual average rate of 1 percent per year to 2020. Over the next ten years, commercial baseline demand will increase by 3.3 Bcf, and will increase by 6.3 Bcf by 2020. (Chapter 4, Table 4.2)

- The baseline forecast estimates moderate to flat growth of industrial natural gas usage. Over the forecast period, industrial baseline demand will increase at an annual average rate of approximately half a percent. Industrial demand will increase by 4.0 Bcf by the year 2010, and by 8.0 Bcf by 2020. (Chapter 4, Table 4.3)

- Electric utility demand for natural gas will increase by 0.7 percent per year to 2020. Electric utility demand will increase by 1.4 Bcf by the year 2010, and by 5.1 Bcf by 2020. (Chapter 4, Table 4.4)

- Total baseline natural gas usage is forecasted to grow at an annual average rate of little under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. (Chapter 4, Table 4.5)

Summary of Baseline Forecast

Date	Residential (Mcf))	Commercial (Mcf)	Industrial (Mcf))	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,851,818	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Note: Baseline forecast excludes natural gas dispositions to the Kenai LNG Plant. See discussion in Chapters 2 and 7.

- The baseline forecast developed in this study was subjected to a number of sensitivity analyses to determine the impact of changes in economic assumptions on natural gas usage. (Chapter 5, page 37)

- Under the high price/high income scenario, prices and income were expected to increase at a rate of one percent per year in real dollars. Under the low price scenario, prices were assumed to decrease at a real rate of one percent per year. Under the low income scenario, income was assumed to be constant in real dollars over the forecast period. (Chapter 5, page 37)

- Changes in price assumptions had larger influences on the baseline forecast than changes in income assumptions. (Chapter 5, Figure 5.2)

- Under a low price forecast, total in-state natural gas usage would grow at a 0.05 percent rate higher than under the baseline forecast. The low price forecast assumes that prices will fall by an annual rate of one percent during the forecast period. The baseline forecast, on the other hand, assumes constant prices. (Chapter 5, Figure 5.1)

Summary of Forecast Sensitivities

High Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

- After examining a range of expanded service opportunities through the state, the largest concentrations of new service opportunities are in the South Central and Interior regions of the state. There are approximately 2.2 Bcf of expanded service opportunities in South Central region and 4.3 Bcf of expanded service opportunities in the Interior. (Chapter 6, Table 6.6)

- There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of Internet server farms and a major petrochemical industry. Both are energy-intensive industries. (Chapter 7)

- It would take the addition of a relatively large Internet facility (i.e., about a one million square foot facility) to impact total in-state usage. We estimate that a high power density, million square foot server farm could use up to 4.3 Bcf per year. (Chapter 7, Table 7.1)

- A major petrochemical facility, on the other hand, could have a more meaningful impact. Based upon statistics from typical world class facilities on the Gulf of Mexico, a 619 ton per year ethylene facility could use as much as 27 Bcf per year. (Chapter 7, Table 7.3)

- All generating units in the state were examined to identify facilities those that could potentially shift their primary fuel to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior section of the state. There are approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Annual natural gas usage would be about 15 Bcf per year if all of the eligible facilities were to switch fuels. (Chapter 8, Tables 8.1 and 8.4)

- There is a supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the marginal costs of existing generating units. This new generation could account for about 12.5 Bcf of natural gas usage per year. However, prior studies of power markets performed on behalf of the Regulatory Commission of Alaska, have noted that Alaska does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. (Chapter 8, Tables 8.10 and 8.11)

- Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. We examined a number of major concentrations of potential gas usage, and modeled the typical costs of supplying natural gas to these potential applications. These results included:

- ***New Service to the Interior:*** Positive opportunities for natural gas service exist based on our initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent. (Chapter 9, page 120)

- ***Fuel Switching:*** Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated. (Chapter 9, page 124)

- ***Gas by Wire:*** There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014. (Chapter 9, page 128)

- ***Expanded Service to the Southcentral:*** Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage, 30-to-40 Bcf per year, currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area. (Chapter 9, page 131)

CHAPTER 1: INTRODUCTION

1.1: Research Overview

The purpose of this report is to examine the future natural gas demand and supply for Alaska communities and businesses. The study was prepared in a manner that provides a host of quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. Our study considers a number of opportunities including expanding natural gas service to retail customers, increased gas-fired power generation alternatives, and the addition of new industries to the Alaska economy.

A number of demand models have been developed throughout the course of this report. The primary set of models estimate customer class specific natural gas usage. These models have been developed to understand the important empirical determinants of natural gas demand, as well as forecasting potential in-state usage under a number of different economic scenarios.

The report uses a geographic information system (GIS) approach for identifying new regional sources of natural gas usage. Our GIS model identifies existing and potential sources of natural gas usage, and maps those locations to existing and future infrastructure development. Volumes by location and region are developed from this approach. Throughout the course of our report, we will define Alaska regions as identified below in Figure 1.1. These regions include: the Far North, the Interior, the Southwest, the Southcentral, and the South Eastern portions of the state.

Our GIS analysis was comprised of two approaches. First, we examine total regional in-state possibilities for expanded natural gas service regardless of distance and economics. This approach essentially defines the outer boundary of potential new natural gas usage in the state. Second, we examine the possibilities of expanding natural gas service within two major natural gas infrastructure systems: the existing local distribution networks in place in Alaska, and the proposed Alaska Highway Route (AHR).

Figure 1.1: Definition of Alaska Regions

We also examine the possibilities of new sources of natural gas usage. These include new natural gas power generation possibilities as well as a number of new commercial and industrial opportunities. The power generation options we consider can be broken into two classes. First, we estimate the opportunities for fuel switching at existing utility and non-utility fuel oil and diesel fired generation facilities. Second, we examine the possibilities of a "gas-by-wire" application where a larger central station power generation facility is located in close proximity to the AHR. Power generated from the gas-fired facility would then be moved by high voltage transmission lines to nearby communities.

We also analyze the possibilities of adding new energy intensive industries to the Alaska economy. These include: the development of an internet server farm; the possibilities of a new petrochemical facility in the state; as well as expansion of existing LNG and ammonia-urea production.

Lastly, no analysis of in-state demand would be complete without examining the cost implications of supplying natural gas to these identified possibilities. In a later chapter of our report, we examine the costs associated with stepping natural gas down from the high pressure AHR transmission line to potential regional natural gas usage applications.

1.2: Organization of Report

This report is organized into a total of ten chapters, three technical appendices, and a bibliography. The technical appendices and bibliography associated with this report are included in Volume 2.

The first chapter is this introduction that gives an overview of the report and its organization.

The second chapter of our report provides an overview of recent Alaska natural gas market trends. This chapter is a general overview over the past several years. A more detailed analysis, over a longer time period, can be found in Appendix 1 (Volume 2).

The third chapter of our report provides a general discussion of demand modeling and the techniques typically employed in this type of research. For those readers less interested in these technical details, this chapter of the report can be skipped without loss of context. For those readers looking for greater detail on natural gas demand modeling, Appendix 2 (Volume 2) has been provided for that purpose.

The fourth chapter of our report provides our baseline forecast of natural gas usage by major customer class: residential, commercial, industrial, and power generation. This chapter highlights the results of our forecast, with little discussion of our actual model and its statistical results. Those readers looking for greater empirical detail, in terms of the statistical models and their results, should refer to Appendix 3 (Volume 2).

The fifth chapter of our report subjects our baseline forecasts to a number of different assumptions about economic conditions in Alaska and how they could impact in-state natural gas usage.

The sixth chapter of our report examines new retail service opportunities for natural gas. This chapter highlights our GIS approach and maps out new usage opportunities on a regional and geographic proximity basis.

The seventh chapter of our report examines new natural gas opportunities through additions of new industries to the Alaska economy. This chapter provides some estimates of potential natural gas usage by the previously discussed internet server farm and the development of a new major petrochemical facility. We also consider expanded opportunities for natural gas usage at existing Alaska industries. In particular, expanded usage at existing LNG and urea production facilities.

The eighth chapter of our report examines new opportunities for natural gas fired power generation. This chapter identifies fuel switching applications, and potential natural gas usage volumes that could result from a shift in primary fuel at certain power generation stations and locations. We also examine a gas-by-wire application in this chapter of our report.

The ninth chapter of our report examines the cost of supplying natural gas to a number of the opportunities identified in the earlier chapters of our report. Our primary emphasis has been on the new service opportunities in relatively concentrated areas, in addition to power generation applications.

The tenth chapter of our report presents our overall conclusions. Also included with this report, in Volume 2, is an exhaustive bibliography of the leading articles in natural gas industry supply and demand modeling.

CHAPTER 2: RECENT TRENDS IN ALASKA'S RETAIL NATURAL GAS MARKETS

This chapter of our report will examine some of the more recent trends associated with the major natural gas consuming sectors in Alaska. A more detailed, longer run historical analysis has been presented in Appendix 1.

2.1: Data Used in the Analysis of Alaska Natural Gas Usage

The following discussion, as well as the models that we will develop in subsequent chapters, utilizes data from the EIA 176 database published by the U.S. Department of Energy, Energy Information Administration (EIA). This database is developed and maintained from annual survey information collected by the EIA under EIA Form 176. All major interstate natural gas pipeline companies, intrastate natural gas pipeline companies, investor and municipally owned natural gas distributors, underground natural gas storage operators, synthetic natural gas plant operators, among other providers of natural gas service, are required to complete this form. The completion of this report is mandatory under the Federal Energy Administration Act of 1974.

For a typical LDC, the EIA Form 176 requirements include annual reporting on the disposition of all gas flows over the company's system. This includes accounting for all gas sales, prices (average revenues), and customers for residential, commercial, industrial, and any other retail customer class. In addition, LDCs must report any transportation services (and volumes) for non-core customers. Thus, if a commercial or industrial customer is within the city gate, but receives gas from a third party, the LDC is required to report the volumes it transports to these customers even though the LDC is only providing transportation services.

In the information reported for Alaska natural gas companies, two LDCs filed information on sales, customers, and transportation volumes. The majority of their disposition was associated with traditional retail sales (i.e., residential, commercial, industrial, etc.). However, starting in 1992, Enstar began reporting transportation volumes for one industrial customer.[1] In 1995, the Company began reporting transportation volumes for commercial customers as well. Since 1995, the number of non-core commercial customers for Enstar has grown significantly. In 1995, there were 62 commercial customers receiving transportation service only from Enstar. This increased to 187 in 1996; 401 in 1997; and 768 in 1998. By 1999, this number has grown to 883 commercial customers taking only transportation service.

[1]In such a situation, if an LDC is transporting gas on behalf of a customer within the city gate, then that customer is being served by a competitive third party, presumable a competitive retail natural gas marketer. Thus, identifying transportation customers within an LDC's service can give some indication of the degree of competition within that particular area.

Other companies with pipeline assets are also required to report transportation and sales volumes even if they are not an LDC. According to the data included in the EIA 176 database, there were 6 non-LDCs reporting either transportation and/or direct sales. These included Arco Alaska, Inc., Chevron USA, Marathon Oil Company, Phillips Alaska Natural Gas Company, Ukpeaqvik Artic Slope, and Union Oil Company of California (UNOCAL). In 1999, these companies, collectively, served 11 commercial customers, of which 2 were transportation customers alone. In the same year, these companies collectively served 9 industrial customers. Enstar provided transportation service to three industrial customers.

The EIA database that we used in our historic trends analysis, as well as in the development of our forecasting models, excludes information from other natural gas uses that are reported separately to the DOE. These include field uses of natural gas in oil and gas production, internal company use of natural gas, pumping and compressor station use of natural gas, and liquefied natural gas (LNG). None of these gas usage activities are included in the commercial and industrial series analyzed in this chapter, nor were these natural gas uses included in commercial or industrial forecasting models. Gas Dispositions to the Kenai LNG Plant are excluded from the EIA data series because the LNG it is exported and not considered as an in-state requirement. However, the role of LNG in Southcentral Alaska is important since it accounts for close to 36 percent of total gas dispositions in the Cook Inlet area (see discussion in Chapters 7 and 9).

In addition to usage and price information included in the EIA Form 176, we compiled additional information to supplement the data we would use to specify our demand equation. This includes energy price information for alternative fuels such as diesel, fuel oil, and electricity. This information was also collected from the US Department of Energy, and is published every year in the Annual Energy Report. We also collected employment and state gross product information from the US Department of Commerce, Bureau of Economic Analysis (BEA).

2.2: Recent Trends in Retail Natural Gas Prices

Over the past several years, most Alaska customer classes have experienced price decreases for natural gas service. These trends have been presented in Figure 2.1. In this figure, customer class retail prices are measured as average revenues (expressed in non-inflation adjusted, money-of-the-day dollars).

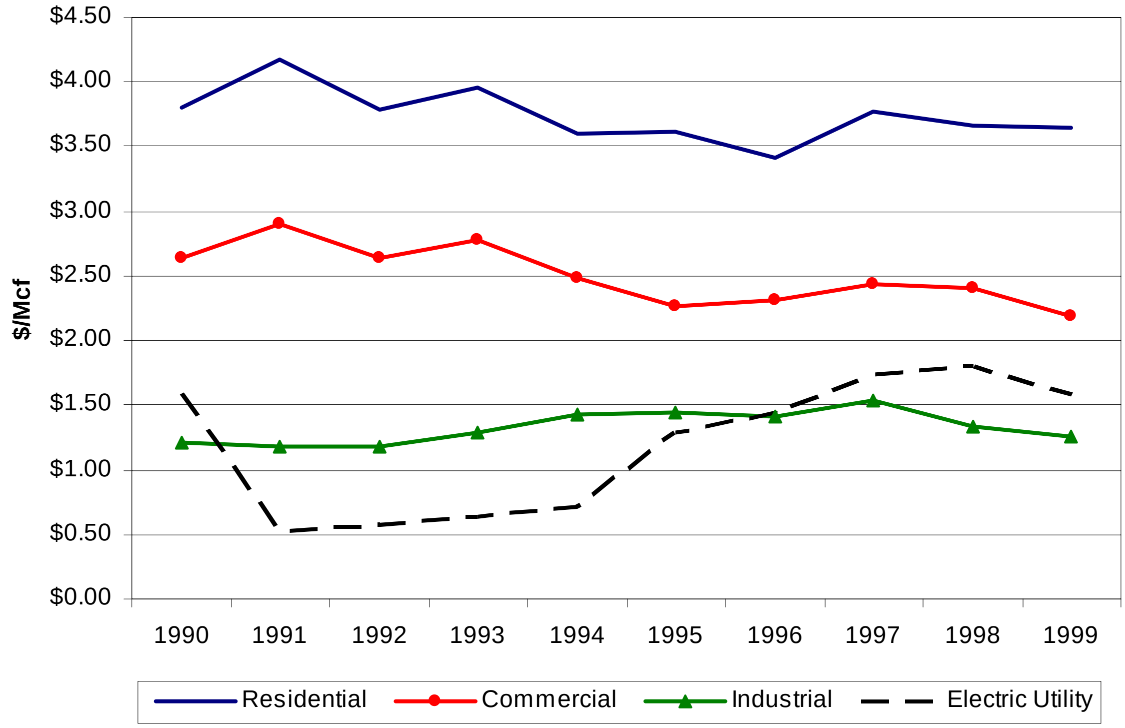

Figure 2.1: Recent Trends in Alaska Natural Gas Prices by Sector

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

As seen from the figure, residential rates tend to be the highest of all Alaska customer classes. Commercial rates are the next highest, with the differential between commercial and residential rates falling by close to 50 cents per Mcf over the past decade. Since 1990, the relative ranking of prices for electric utilities and industrial customers has shifted. Prior to 1996, electric utilities generally paid less on a Mcf basis for natural gas service than industrial customers. This changed in 1996, with electric utilities paying slightly higher rates. Since electric utilities in Alaska tend to sign longer term fuel agreements, this shift could reflect different contract terms and conditions.

Natural gas retail prices are usually composed of two parts: the base rate and the purchased gas acquisition (PGA) rate. The base rate covers the cost of providing service and return on, and of, investment for the local distribution company. The PGA, on the other hand, is the cost of obtaining natural gas, which is a pass-along to end-users. The different between the total retail rate and the PGA can be thought of as the cost of providing non-fuel related service. Figure 2.2 presents the relative changes of residential retail prices and PGA adjustments for Enstar, the state's largest natural gas local distribution company.

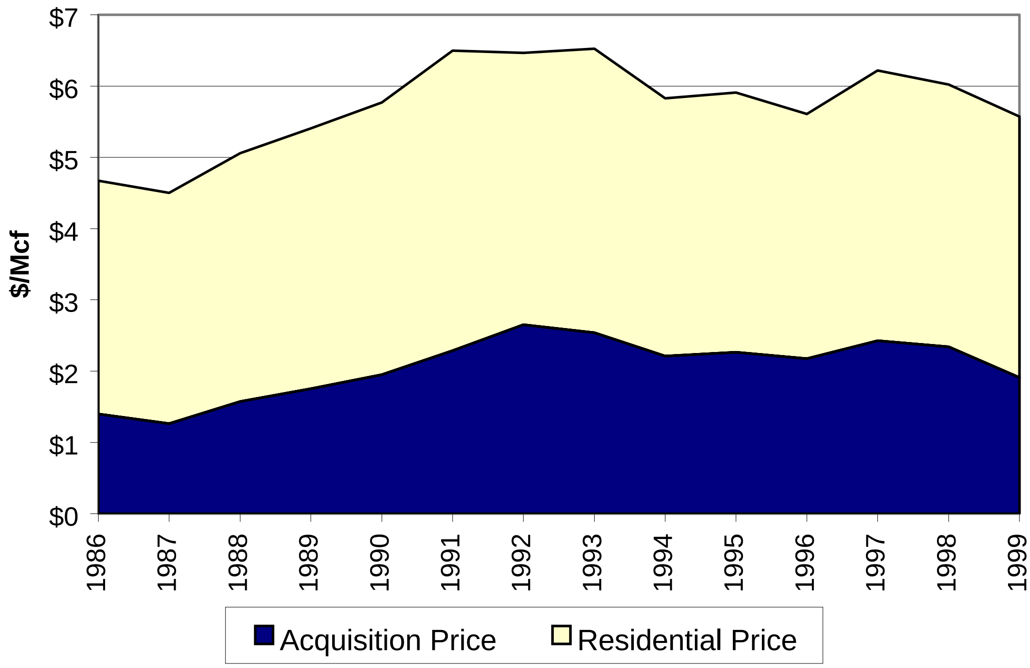

Figure 2.2: Residential Retail Rates and Gas Acquisition Costs -- Enstar

Source: U.S. Department of Energy, EIA Form 176.

As seen in Figure 2.2, retail prices have, in general, followed shifts in gas acquisition charges paid by LDCs. The lower area highlighted in the figure represents the acquisition cost of the LDC, while the higher area represents the total residential price. The difference between these two areas represents the non-fuel distribution charges associated with the residential rate, which has been relatively stable at an average of $1.50 per Mcf over the past five years.

A comparable analysis has been provided in Figure 2.3. This figure compares residential markups,[2] commercial markups, and the differentials between gas acquisition charges and wellhead prices. All three series tend to move in the same direction indicated that most of the recent trends in retail rates are driven by the cost of gas that is incurred by LDCs. The graph presented in Figure 2.3 compares relative price markups for Enstar.

[2]Residential mark-ups are defined as the residential retail price less the overall system gas acquisition cost. Commercial mark-ups are simply the commercial retail price less the same gas acquisition cost.

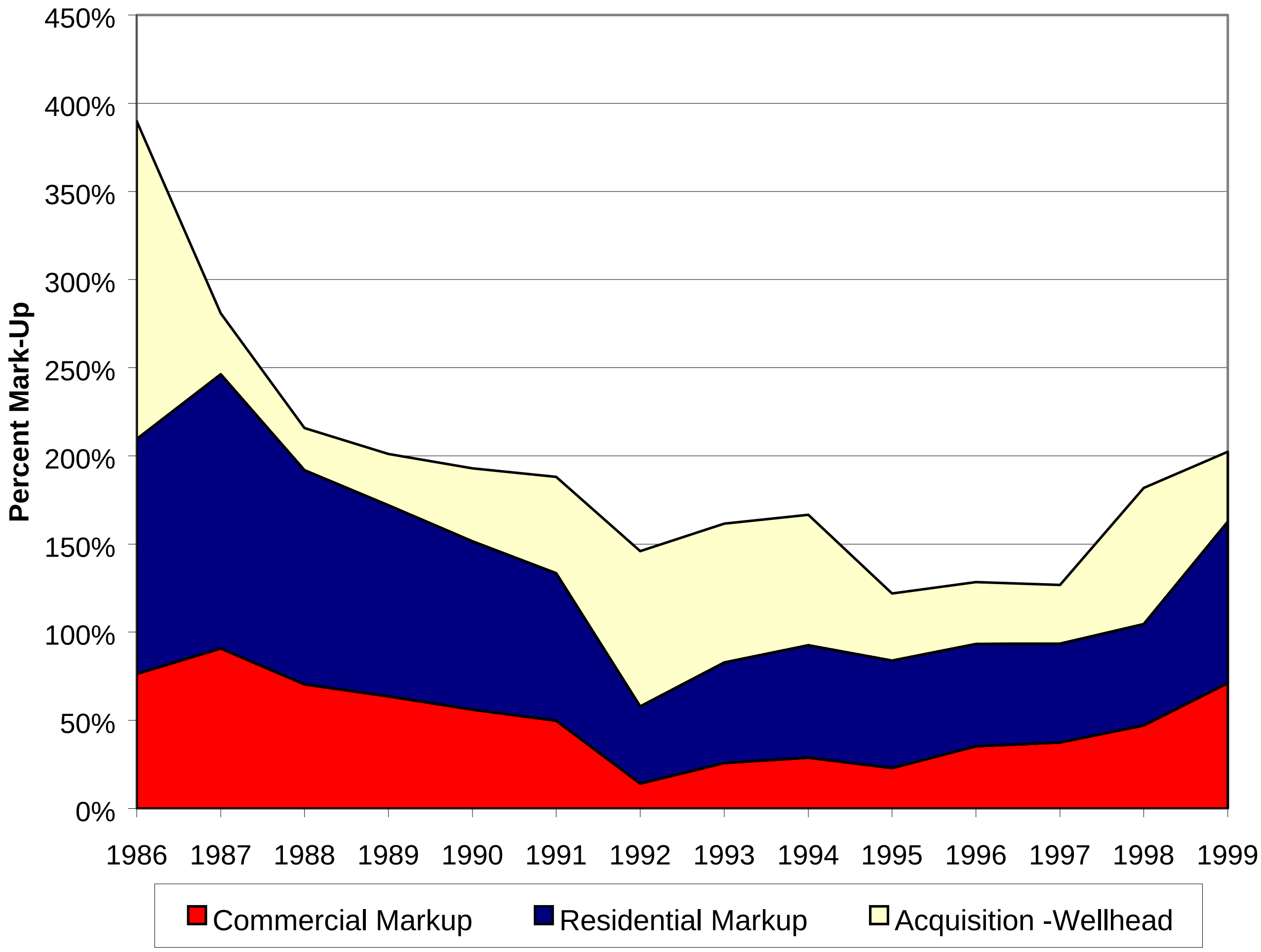

Figure 2.3: Comparison of Residential, Commercial, and Wellhead to PGA Markups – Enstar

Source: U.S. Department of Energy, EIA Form 176.

2.3: Recent Trends in Natural Gas Customer Growth

Over the past 10 years, residential natural gas customer growth has been relatively strong. Figure 2.4 presents annual number of residential and commercial customers while Figure 2.5 presents the annual number of industrial customers. Residential customer growth over the past decade has averaged at an annual rate of about 2.5 percent, while commercial customers have grown at an annual average rate of 1.3 percent. Industrial customer growth has been very limited, and over the past decade has hovered between 8 and 11 customers.

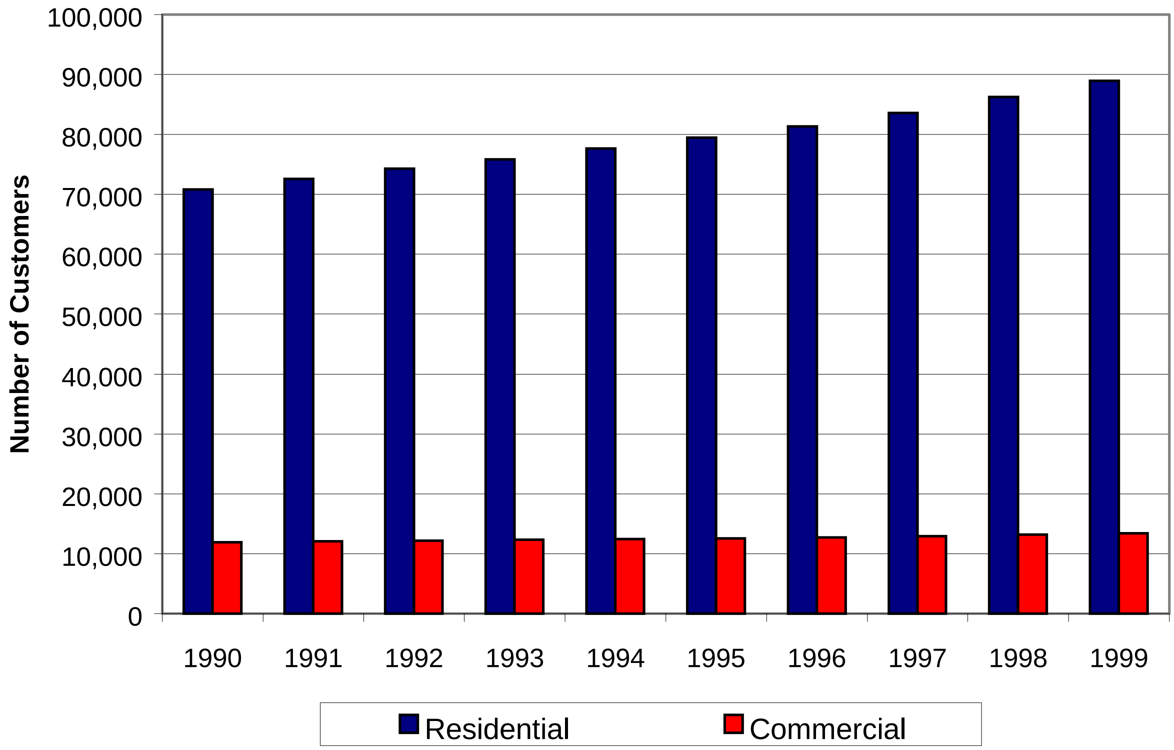

Figure 2.4: Annual Number of Residential and Commercial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

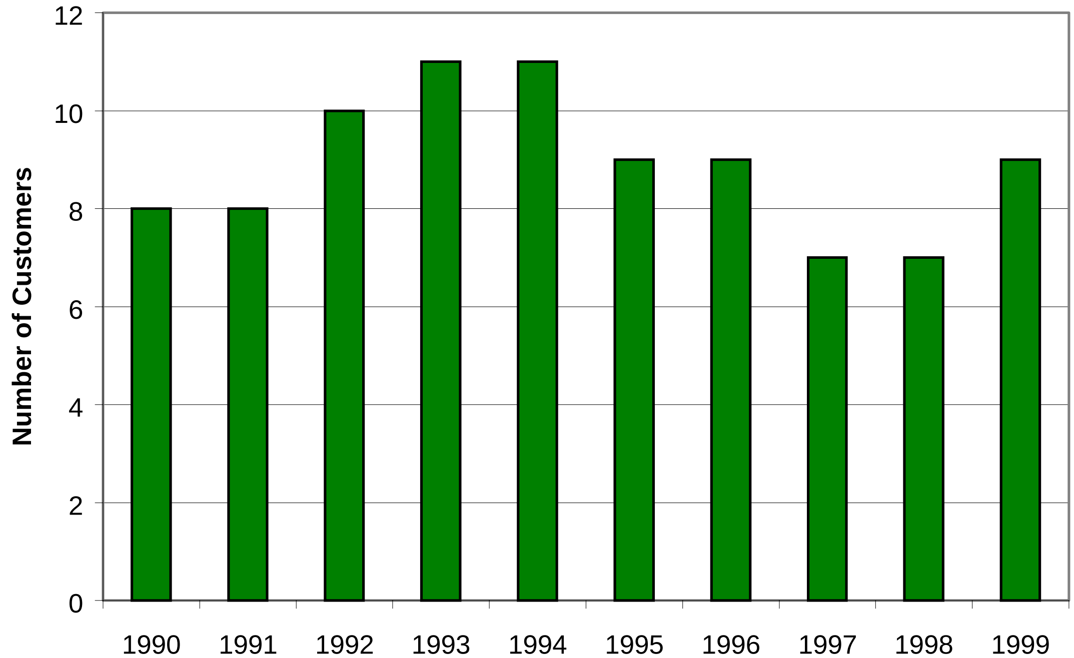

Figure 2.5: Annual Number of Industrial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

2.4: Recent Trends in Natural Gas Usage

Industrial customers are the largest users of Alaska natural gas. Total industrial natural gas usage averaged around 73 Bcf annually during the past decade. Usage for these customers took a decided dip between 1996 and 1998, but has rebounded since that time. The same trend is noticeable for electric utility customers of natural gas who averaged about 30 Bcf per year over the past decade. Both customer classes have tended to have relatively flat usage growth throughout the 1990s.

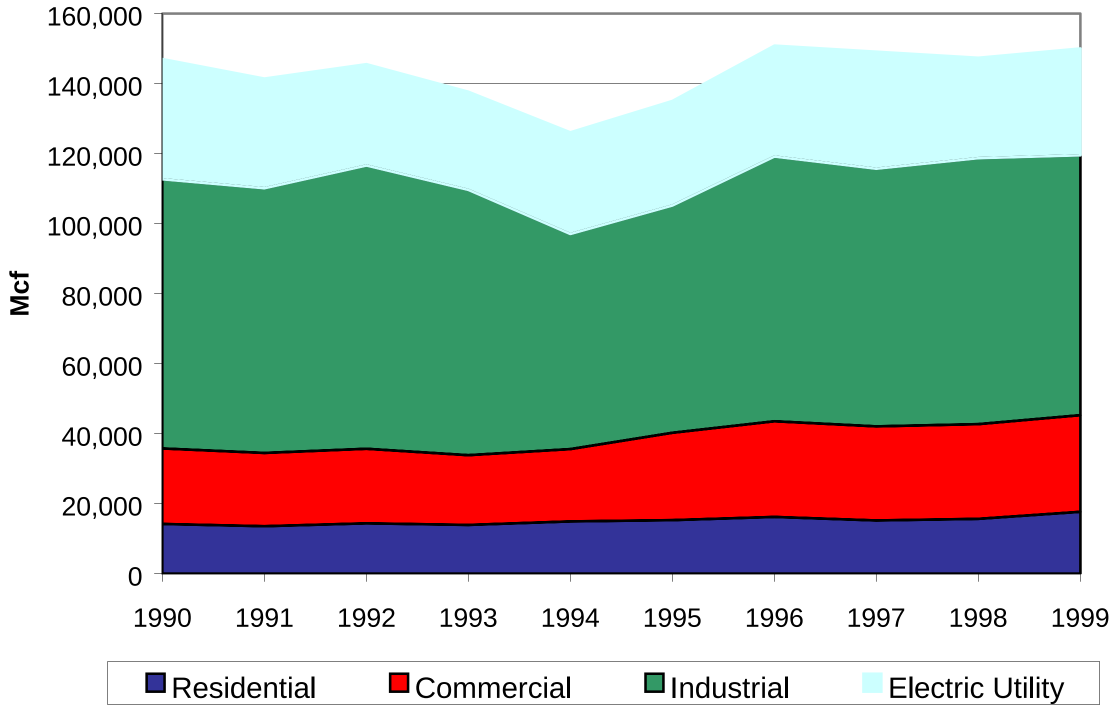

Figure 2.6: Recent Trends in Alaska Natural Gas Usage (Annual Mcf)

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Residential and commercial customers, have both smaller, and more stable usage patterns than their larger industrial and electric utility counterparts. Over the past decade, residential usage has grown by an annual average rate of 2.8 percent, while commercial usage has grown by 2.7 percent over the same time period. In recent times, usage for residential customers has averaged around 15 Bcf per year, while commercial usage has averaged about 24 Bcf per year.

Figure 2.7 presents recent trends in residential average usage. As noted in earlier graphs, residential customer growth has been relatively steady and consistent over the past decade. Usage, on the other hand, has moved sporadically. In some years usage has been up dramatically, like the 12 percent increase in 1998-1999, while in other years it has fallen, like the 6.3 percent decrease in 1996-1997. As a consequence, average usage has tended to move in fits and spurts.

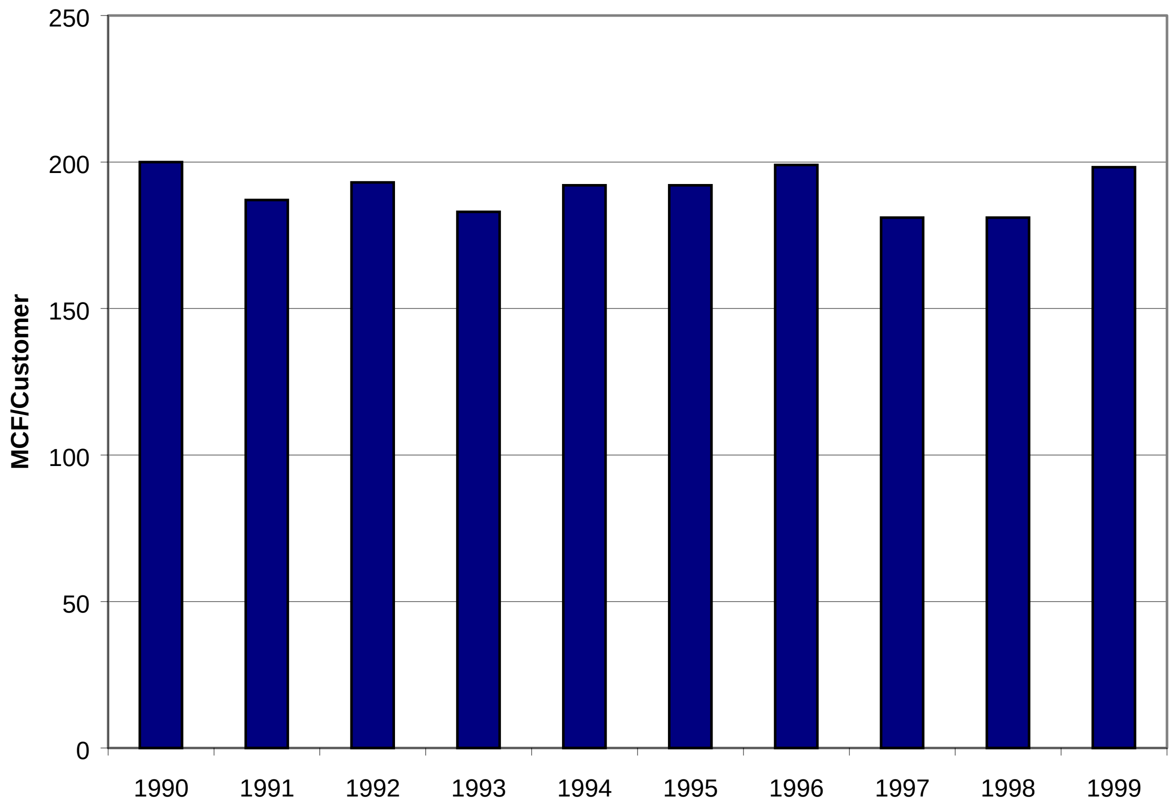

Figure 2.7: Residential Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Figure 2.8 presents average usage for commercial customers. Unlike the recent trends with residential customers, commercial customers have exhibit more stable average usage growth over the past decade. Average usage for commercial customers has grown at an average rate of about 1.4 percent over the past 10 years.

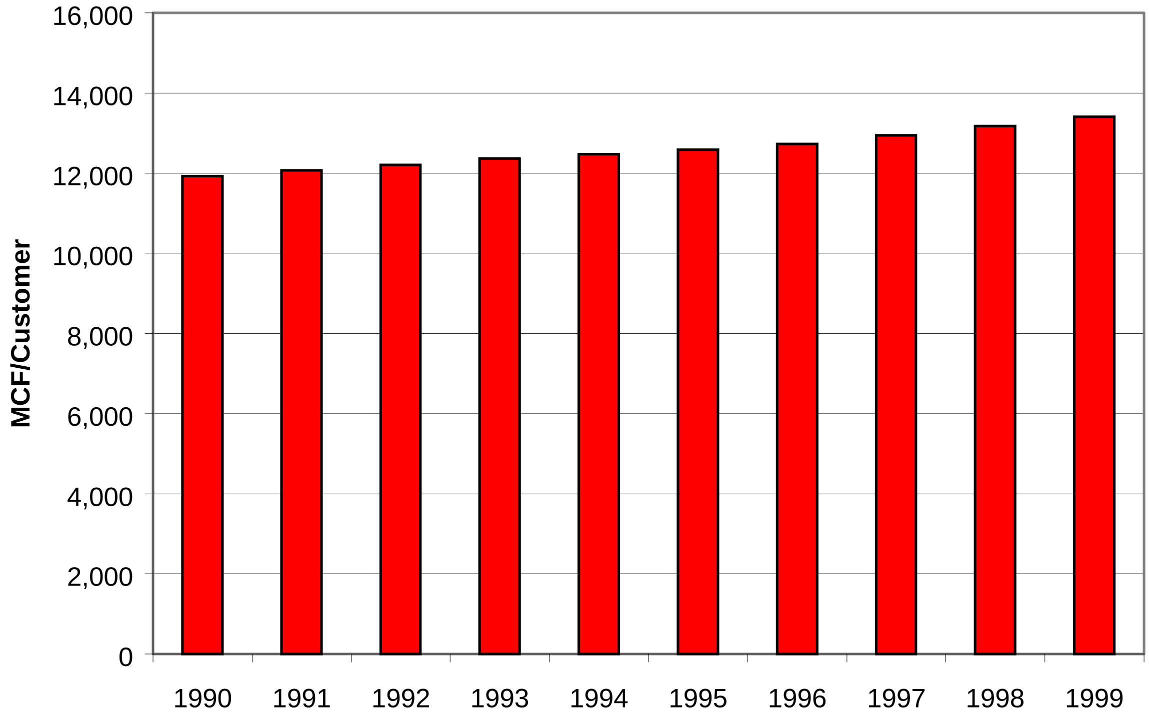

Figure 2.8: Commercial Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

CHAPTER 3: REVIEW OF DEMAND AND SUPPLY MODELING LITERATURE

This chapter of our report presents an overview of general issues associated with demand modeling, an overview of various different approaches to modeling natural gas demand, as well as an overview of the methods that we will employ in the development of our baseline natural gas demand models.

For the more general reader, this chapter of the report can be skipped without loss of context of the overall study. For those readers looking for additional detail on the modeling of natural gas demand, Appendix 2 was prepared for this purpose.

3.1: General Issues in Modeling Demand

Modeling natural gas demand and supply in local, regional, and national markets is important for a number of reasons. These models give researchers and other market observers information about the structure and composition of demand and supply. Futhermore, the results of these models inform researchers about the magnitude of future demand and its sensitivity to key determinants such as energy prices and income. This information is used to understand:

- Past trends and the determinants of realized demand and supply;
- The responsiveness of demand and supply to changes in its important determinants; and
- Future demand and supply under different assumptions about future scenarios.

From its most basic perspective, the relationships of demand and supply can be summarized as:

- Demand is a function of prices, income, and tastes and preferences; and
- Supply is a function of input factor prices, technology, and other factors.

Transforming these theoretical relationships into measurable statistical equations is difficult. The way empirical data is measured may not conform with the structure implied by theory. For instance, theory suggests that the quantity demanded is a function of prices and other important variables. Yet the "appropriate" prices may not be readily available or easily generated. Furthermore, in many energy pricing situations, prices are set in a multitude of different manners (i.e, average rates, two-part tariffs, increasing block rates, decreasing block rates, time of day and seasonal pricing, etc.) Data measurement problems in terms of definition, sampling, and aggregation complicate model specification and statistical estimation.

Most quantitative analyses of supply and demand are broken into two types: cross sectional and time series. Cross sectional models typically examine causal relationships across a collection of variables over a fixed period of time. As suggested by the nomenclature, time series models focus on time dependency.

Cross sectional models are used to examine existing determinants of either supply and demand. These models are structural in nature since they attempt to flush out causality and typicially employ many different determinants of demand or supply as independent (explanatory) variables. Thus, a model of the industrial demand for energy, could consider a number of different explanatory factors that include economic characteristics (i.e., relative energy prices, output levels, etc.) and technical characteristics of the facilities (i.e., number of boilers, fuel switching abilities, heat to power ratios, etc.).

Cross sectional models provide useful information on the relative statistical importance of these variables at a given period of time but are less useful in estimating how relationships change over time. Thus, their ability to serve as a springboard for forecasting is limited. In addition, these types of approaches usually require detailed disaggregate information (usually at the firm or production or consumption unit level), that can be difficult to acquire, particularly for independent research.

Time series models, on the other hand, are more useful in examining the dynamic determinants of demand or supply. The advantage of time series models is that they can convey information about how supply or demand relationships have varied historically, and where particular “structural breaks” in certain trends have occurred. These models are equally useful as a starting point for forecasting since most forecasts are developed from historical trend relationships. Their disadvantage is that data availability usually limits the range of the determinants measuring the supply or demand relationship.

Another consideration in time series models is that they can be developed in two different fashions. The first is traditionally referred to as a “structural econometric” approach while the second is commonly referred to more generally as a “time series” approach.[1] The structural econometric approach is concerned with the estimation of relationships suggested by economic theory across time. For instance, in demand analysis we might look at the relationship of energy demand relative to prices, income, weather, and other relevant variables. Such models serve two purposes. First, they allow economic hypotheses to be tested

[1] A seminal text on the econometric analysis of time series is Andrew Harvey. (1991) *The Econometric Analysis of Time Series*. Second Edition. Cambridge, Massachusetts: The MIT Press.

empirically.[2] Second, they provide a framework for making rational and consistent predictions (i.e., forecasting).

Pure time series approaches, on the other hand, are more generalized trend analyses based on statistical extrapolation techniques rather than theoretic relationships. Traditional time series analysis forecasts the time path of a variable with models that explicitly contain stochastic components to measure their dynamic relationships.[3] Difference equations, such as moving averages of either the error term, the dependent variable, or both, are at the core of these types of approaches. Uncovering the dynamic path of a series improves forecasts since the measurable components of the series can be extrapolated into the future.

There is a third modeling option known as cross-sectional/time series models. These approaches, as the name suggests, merge these two approaches to maximize the relative benefits, and minimize their relative shortcomings. The problem is that, in many instances, pooled cross sectional approaches require relatively advanced statistical techniques, as well as being very data intensive.

Another important question in measuring either supply or demand relationships is the determination of which of the two general approaches should be facilitated. In many instances, this is usually done by purpose of the study as well as the practical limitations of the data. If a researcher is interested in examining the price elasticity of the residential demand for natural gas, then a cross sectional analysis of account-specific information would be a useful approach. However, many researchers outside of natural gas local distribution companies usually have limited or no access to this type of information. The US Department of Energy, however, does report aggregate information by customer class across time, thus some type of time series approach may be more readily facilitated.

Lastly, determining the appropriateness of a particular model is an important specification issue. Often, applied modeling can emphasize goodness of fit of a particular model to the expense of all other considerations. However, more balanced consideration should include such factors as:

- *Consistency with theory*. Ensuring the quantitative estimates of model parameters exhibit mathematical signs and magnitudes consistent with economic theory (i.e., negative price elasticities and positive income elasticities).

- *Consistency with goals*. Obviously specifying and measuring time series models can be more important for forecasting goals, while cross sectional models can be more important for research

[2] *Ibid.*, 1.
[3] Walter Enders. (1995). *Applied Econometric Time Series*. New York: John Wiley and Sons, Inc.

questions related to the relative importance of structural determinants.

- *Parsimony*. Ensuring that models that are not overly specified and are straightforward.

- *Robustness*. Ensuring that models are not overly dependent upon unique specifications or time periods under consideration.

The modeling of supply and demand for natural gas builds on a broad arena of industry-based energy modeling. Natural gas supply modeling, for instance, is conditioned by a number of earlier studies in petroleum supply modeling. Natural gas demand modeling is heavily linked to the electric power industry.

The study of natural gas supply and demand also is linked to technical-engineering models, sociological models, economic models, and hybrid models that employ varying combinations of these factors. Econometric analysis, as opposed to time series approaches, has dominated much of the supply and demand modeling literature. The preference for these econometric approaches is probably to be expected. First, econometric approaches are useful in explaining the changes in natural gas disposition that result from general changes in the industry—particularly, the response to shifts in price and the general degree of price volatility in the industry since the early 1970s.

Second, while data measurement and implementation is still a challenge in the analysis of energy demand and supply, accessibility of the information has improved considerably. Reporting requirements and data collection developed at the U.S. Department of Energy gives researchers a consistent source of information to examine and corroborate existing studies in the energy industry. With the advent of the internet, the electronic availability of the information enhances the ability to concentrated important efforts in understanding empirical relationships rather than collecting basic information on industry disposition and trends.

Third, over the past twenty years, econometric approaches have become more accessible to industry practitioners as software packages have reduced the programming work needed to do the earlier models by an exceptional order of magnitude. Today, many readily available statistical packages can estimate either supply or demand models in matter of seconds. The reduction in computational difficulty has helped facilitate the development of a large body of analysis related to important energy relationships.

3.2: Empirical Studies of Natural Gas Demand

One of the pioneering authors in demand modeling, for many sectors that go beyond just energy demand modeling, is Hendrick S. Houthakker. His studies in energy demand modeling were extensive, and provided some of the first insights into the importance many structural determinants of energy demand. His work is still commonly cited in principal textbooks of microeconomic theory.[4] Houthakker's work in energy demand modeling, developed in the early 1950s, was a basis for his broader work in overall demand modeling.[5]

On the more practical side, there is a considerable amount of work in natural gas demand modeling that rests outside the traditional academic literature. This work is associated with the modeling conducted within the process of regulated natural gas distribution companies, commonly referred to as local distribution companies or LDCs. These LDCs use forecasting models for internal planning process in meeting supply (commodity) and capacity (transportation and storage) needs.[6]

Many of the theoretic developments of natural gas demand modeling have come from the academic literature. A good portion of this analysis has focused on residential, and to a lesser degree commercial, demand for natural gas. These models are primarily econometric in nature since the purpose of many are to get accurate estimates of price, income, and weather related sensitivities of natural gas demand.

Another practical consideration in reviewing the literature on natural gas modeling is its relationship with its sister energy industry, electricity. A number of the earliest works in energy demand concentrated in the area of electricity (i.e., Houthakker) and not natural gas. It seems likely that one of the initial reasons for more comprehensive development of demand modeling in the electricity industry is associated with its greater degree of data availability. Thus, any survey of natural gas demand modeling will have to include some references to the development in the power industry as well.

There are a number of surveys in the literature dedicated to natural gas and energy demand modeling in general. One of the earliest and most comprehensive surveys of energy demand modeling was prepared by Douglas R. Bohi for the Electric Power Research Institute (EPRI).[7] While the overall

[4]Hendrick S. Houthakker and Lester D. Taylor. (1966). *Consumer Demand in the United States, 1929-1970*. Cambridge: Harvard University Press.

[5]For instance see: Hendrick S. Houthakker. (1951), "Some Calculations of Electricity Consumption in Great Britain." *Journal of the Royal Statistical Socie*ty. Series A, 114, Part III, 351-71.

[6]A general primer on the role of natural gas demand forecasting and how it relates to overall LDC planning can be found in: Charles Goldman, et al. (1993). *Primer on Gas Integrated Resource Planning*. Berkeley, California: Lawrence Berkeley Laboratories.

[7]Douglas R. Bohi. *Price Elasticities of Demand for Energy: Evaluating the Estimates*. Palo Alto: Electric Power Research Institute.

purpose of the study was to examine price elasticities, the study is an excellent overview of demand modeling since price elasticities are usually outputs derived from an overall analysis of demand determinants. An update to this study was prepared in 1984 by Bohi and Zimmerman.[8]

A more recent study, which emphasizes the development of the literature in residential energy demand modeling, was presented by Reinhard Madlener.[9] In the survey, Madlener attempts to update the earlier Bohi work, as well as breaking the existing econometric literature into a number of useful different categories. These include studies associated with log-linear functional forms, transcendental logarithmic (translog) functional forms, qualitative choice models (also know as discrete choice models), household production theory (end-use modeling), and pooled time series-cross sectional models.

Madlener presents a table associated with each of these types of models. This table has been replicated, with additional comments and analysis, in Appendix Table A.2.1. The following discussion provides a brief overview of the literature along the lines developed by Madlener. A more detailed discussion of each of the general demand modeling methods is provided in Appendix 2.

3.2.1: Log-Linear and Double Log Models: The typical log-linear and double log models are relatively straightforward and tend to be the model of choice, particularly for industry practitioners. The benefit of the log-linear and double log form is that coefficients can easily be translated into elasticities. In the double log form, the parameter for price is interpreted as the price elasticity of demand, while the parameter estimate for income can be interpreted as the income elasticity of demand.

3.2.2: Transcendental Logarithmic (Translog) Models: Translog models became popular in the 1970s with the advent of the Christensen, et al. (1973) approach of estimating industrial production, and later with cost functions and consumer-utility functions.[10] This approach was applied to the electric power

[8]Douglas R. Bohi and Martin B. Zimmerman. (1984). "An Update on Econometric Studies of Energy Demand Behavior." *Annual Review of Energy*. 9: 105-54. The Bohi and Zimmerman (1984) elasticity estimates vary considerably but two general conclusions emerge. First, price elasticities for residential tend to be under 1.0. Two, elasticities are higher (in absolute value) as the analysis moves residential to commercial, to industrial customers. Elasticities increase in absolute value since larger customers tend to have more fuel substitution opportunities.

[9]Reinhard Madlener. (1996). Econometric Analysis of Residential Energy Demand: A Survey. *Journal of Energy Literature*. 2:3-32.

[10]Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1973) "Transcendental Logarithmic Production Frontiers." *The Review of Economics and Statistics*. 55:28-45. Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1975) "Transcendental Logarithmic Utility Functions." *The American Economic Review* 65: 367-83.

industry in 1976, and has become commonplace for a considerable amount of the energy economics research.[11]

The translog specification is a quadratic function with its elements expressed in terms of their natural logarithm. This specification is a second order approximation around a given point for the Cobb-Douglas production function. The Cobb-Douglas production function allows declining marginal products for all inputs, and also assumes that opportunities exist to substitute inputs in production without gaining or losing output.

The advantage of the translog approach is that it provides some structure on the assumed production/utility function under investigation. The parameters associated with the own and cross-price terms provide estimates of own and cross-price elasticities of demand. In additional, the translog approach allows for a more flexible functional form that enables empirical validation of utility-function properties. For example, while the Cobb Douglas function imposes unitary elasticity of substitution among inputs, the translog enables the data to determine the degree of input substitutability. In general, this flexible functional form enables the data to determine if the assumed functional form is correct, and imposes fewer a-priori restrictions on model specification.

The approach, however, is not without its potential problems. First, translog models require a significant amount of information, which can be difficult to attain. Second, these models can be relatively difficult to apply and interpret. This has led many practitioners to steer clear of these approaches. Third, the parameter estimates in many instances do not tend to be robust or stable, and can lead to some erroneous results. Last, the model tends to lend itself better to cross-sectional analyses, and, as a result, is not a very useful tool for forecasting.

3.2.3: Qualitative Choice and End Use Models: Most demand models prior to the early to mid 1970s, and even to this day, use continuous variables to measure energy consumption. There are equally interesting empirical applications, however, that examine not how much of a particular resource is utilized, but whether or not that resource is utilized at all. Such approaches are discrete in nature and have led to the development of qualitative choice, or discrete choice models of energy usage.

Discrete choice models are those in which the dependent variable is a discrete variable. The simplest application is one where the dependent variable is a binary choice variable that represents a simple positive or negative response. The dependent variable takes the value 1 if the choice is made, and 0 if the choice is not made. Independent variables are then used to estimate parameters influencing that choice.

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[11] Laurits Christensen and William Greene. (1976). "Economies of Scale in U.S. Electric Power Generation." *Journal of Political Economy*. 84 (4): 655-76.

Discrete choice models can be powerful tools to examine individual customer choice behavior and the factors influencing those decisions. Sensitivities, developed through the calculation of odds ratio statistics, can then be derived. These odds ratio statistics give some indication on how the probability of making a particular discrete energy consumption decision change as the independent variables change. In some natural gas and energy end use applications, these models provide interesting information on appliance usage and potential changes in penetration rates resulting from shifts in natural gas prices.

These qualitative based models, however, usually require specific and relatively comprehensive end use information. Typically, data used in these types of analyses are from individual consumer surveys. Thus, such empirical approaches are limited, if customer, or decision making unit information is not available. In addition, these types of models can tend to be more static in nature making it difficult to use for long forecasting and trend analysis.

3.3: Methods and Data Used to Develop the Baseline Demand Model

As noted above, there are a number of empirical modeling techniques that have been facilitated in the literature. However, one of the most common and successful approaches for examining natural gas demand are the log-linear and double log models first developed in the 1960s. Our baseline models of natural gas demand are based upon those approaches. There are a number of advantages associated with the traditional double-log models. These include:

- They are straightforward approaches that are parsimonious and easier to implement;

- They are general models that are applicable to a wide range of data;

- In the absence of detailed, account specific survey data, these models serve as the best approach for fitting demand curves for the broad customer classes we are examining (i.e., residential, commercial, and industrial);

- The majority of the past academic and trade literature has been based upon these approaches; and

- These approaches have the advantage of providing considerable descriptive information in addition for being good tools for developing forecasts.

This study has developed baseline models for each major consuming sector in Alaska's natural gas markets. These include residential, commercial, industrial, and electric utility.

In looking at natural gas demand, the goal was to find a consistent source of information that was documentable and widely accepted as authoritative. Based upon our past experience, we have found that the information provided by the Department of Energy, Energy Information Administration (EIA) provides the most comprehensive, and documentable source of information for natural gas usage. This information is compiled annual by the EIA in EIA Form 176. A discussion of EIA Form 176, and the data collected in this annual survey.

The descriptive statistics for all the variables that were utilized in the baseline demand models are presented in Table 3.1.

Table 3.1: Descriptive Statistics for Baseline Model Dataset (1986 – 1999)

Variable Name	Number of Observations	Mean	Standard Deviation	Minimum	Maximum
Residential NG Usage, Mcf/yr	14	14,364,367	1,561,998	12,090,998	17,633,864
Commercial NG Usage, Mcf/yr	14	23,010,401	3,015,288	20,002,655	27,667,159
Industrial NG Usage, Mcf/yr	14	70,717,120	7,004,328	59,341,410	80,937,950
Electric Utilities NG Usage, Mcf/yr	15	31,306,872	2,323,032	28,024,737	35,569,901
Number of Residential Customers	14	75,892	7,242	65,953	88,924
Number of Commercial Customers	14	12,290	643	11,243	13,409
Number of Industrial Customers	14	9.29	1.77	7.00	13.00
Average Revenue from Residential Customers (1999 $/Mcf)	14	4.20	0.42	3.58	4.88
Average Revenue from Commercial Customers (1999 $/Mcf)	14	2.91	0.45	2.18	3.51
Average Revenue from Industrial Customers (1999 $/Mcf)	14	1.38	0.16	0.99	1.58
Heating Degree Days at Fairbanks (Base 65 degrees F.)	14	13,605	802	12,244	15,142
Per Capita Income (1999 $)	14	27,383	713	25,966	28,629
Manufacturing Gross State Product (1999 $ MM)	14	1,226	199	684	1,457

Data Sources:	***Variables***
EIA-176 "Annual Gas Supply and Disposition Report", 1986-1999	Usage, number of customers, and average revenue for all customer classes except electric utilities.
EIA Electric Power Annual, 1986-2000	Industrial NG Usage
NOAA National Climatic Data Center website	Heating Degree Days
BEA website	Per Capita Income and Gross State Product

CHAPTER 4: BASELINE IN-STATE NATURAL GAS DEMAND FORECASTS

The results from our baseline in-state natural gas demand models are summarized in this chapter of the report. A more detailed description of the statistical models used in this forecast is presented in Appendix 3.

Our baseline in-state natural gas demand forecasts are developed under a set of “business as usual” assumptions. We have forecast in-state natural gas demand for each major customer class to the year 2020 under the assumption that trends over the past five years will be maintained into the forecast period. In the following chapter of our report, we will examine the sensitivities of these forecasts to changes in the underlying assumptions associated with these past trends.

We use a three-fold approach to forecast baseline natural gas demand. First, we estimate econometric time-series models. Natural gas usage in each major sector (residential, commercial, industrial and electric power generation) is the dependent variable to be explained. Explanatory variables include personal income, gross state product, prices, weather, and other important determinants of natural gas demand. The magnitude of these impacts (i.e., elasticities) and their statistical properties are presented in Appendix 3.

Second, we estimate traditional time series trend models. The time series approach extrapolates the underlying trend in natural gas usage over time for each sector. This approach is useful because it is simple to apply and straight forward to interpret. The detailed statistical results, along with a discussion of each of these types of methods, are also presented in Appendix 3.

Third, we average the results of the separate econometric and time-series trend models described above to form a combined forecast. This approach helps pick up the peaks, valleys, and underlying trends in data and is a useful tool for forecasting. The forecast information from each of these approaches has been provided in tables in this chapter of our report. The detailed results from each of the approaches, and their related statistical output, have been provided in Appendix 3.

4.1: Residential Baseline Forecast

The results from our residential in-state demand model are presented in Table 4.1.

Table 4.1: Residential Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time-Series (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	12,090,998	12,198,225		12,198,225
1987	12,256,280	12,499,708	12,406,056	12,452,882
1988	12,529,140	12,808,641	12,540,566	12,674,604
1989	13,588,767	13,125,210	13,655,173	13,390,191
1990	14,164,886	13,449,602	14,151,008	13,800,305
1991	13,561,759	13,782,013	13,445,474	13,613,744
1992	14,349,944	14,122,639	14,537,644	14,330,141
1993	13,857,568	14,471,683	13,585,834	14,028,759
1994	14,895,199	14,829,354	14,873,428	14,851,391
1995	15,230,778	15,195,865	14,947,440	15,071,653
1996	16,179,216	15,571,435	15,908,103	15,739,769
1997	15,146,116	15,956,287	15,415,471	15,685,879
1998	15,616,617	16,350,651	15,926,681	16,138,666
1999	17,633,864	16,754,761	17,594,905	17,174,833
2000	--	17,168,859	17,867,599	17,518,229
2001	--	17,593,192	18,087,424	17,840,308
2002	--	18,028,012	18,310,890	18,169,451
2003	--	18,473,578	18,537,190	18,505,384
2004	--	18,930,157	18,766,257	18,848,207
2005	--	19,398,021	18,998,187	19,198,104
2006	--	19,877,448	19,232,955	19,555,201
2007	--	20,368,724	19,470,649	19,919,686
2008	--	20,872,142	19,711,255	20,291,698
2009	--	21,388,002	19,954,860	20,671,431
2010	--	21,916,612	20,201,450	21,059,031
2011	--	22,458,286	20,451,117	21,454,701
2012	--	23,013,349	20,703,866	21,858,607
2013	--	23,582,129	20,959,711	22,270,920
2014	--	24,164,967	21,218,750	22,691,858
2015	--	24,762,210	21,480,954	23,121,582
2016	--	25,374,215	21,746,434	23,560,325
2017	--	26,001,345	22,015,159	24,008,252
2018	--	26,643,974	22,287,242	24,465,608
2019	--	27,302,487	22,562,653	24,932,570
2020	--	27,977,274	22,841,498	25,409,386
Root Mean Square Error		0.01753		

The results from our in-state residential demand forecast show relatively healthy growth in natural gas usage from the existing residential customer base in Alaska. Overall, we forecast that natural gas demand will grow at an annual average rate of about 1.8 to 1.9 percent per year, under baseline conditions, until 2020. Baseline conditions included a half percent increase per year in per capita income and zero percent increase in real retail residential natural gas prices. In the next chapter of our report, we examine the sensitivity of this forecast to changes in those underlying assumptions.

Under our baseline forecast, residential in-state natural gas usage will grow from a 1999 level of 17 Bcf to 25 Bcf by the year 2020. A graph of this longer run trend is presented below in Figure 4.1

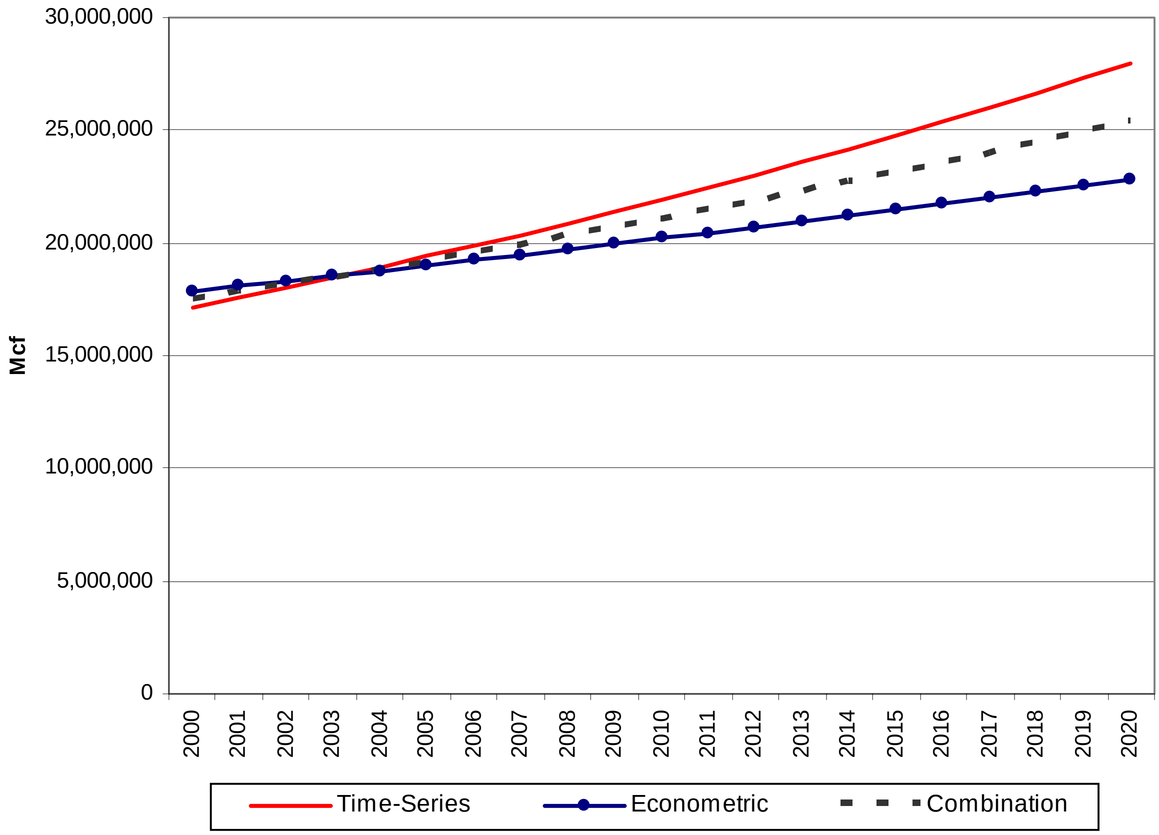

Figure 4.1: Residential Baseline Demand Forecast (2000-2020)

4.2: Commercial Baseline Forecast

Our commercial in-state demand forecast is presented in Table 4.2. A graph of these longer run trends is presented in Figure 4.2. Under business as usual conditions, we forecast long-term commercial natural gas usage to grow at a relatively moderate pace. The average annual rate of growth over the forecast period varies from a high of 1.7 percent in the 2003-2004 time period, to around 1.0 percent or less for the period 2010 onwards.

Commercial natural gas usage is forecast to grow from a 1999 level of 28 Bcf to a 2020 forecast level of 35 Bcf. This forecast assumes zero percent real changes in commercial natural gas prices and a half percent annual increase in per capita income. Deviations from this forecast assumption, and its implications for commercial natural gas usage, will be considered in the following chapter.

Table 4.2: Commercial Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time-Series (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	20,874,011	20,872,099		20,872,099
1987	20,224,143	21,459,238		21,459,238
1988	20,842,041	20,808,703	20,952,886	20,880,795
1989	21,738,412	21,424,696	21,111,727	21,268,211
1990	21,621,850	22,320,431	21,608,730	21,964,580
1991	20,897,429	22,203,516	20,147,636	21,175,576
1992	21,299,274	21,477,732	20,996,129	21,236,931
1993	20,002,655	21,877,606	20,617,698	21,247,652
1994	20,697,859	20,580,149	22,079,885	21,330,017
1995	24,978,977	21,272,817	24,597,540	22,935,179
1996	27,314,942	25,553,385	27,507,854	26,530,620
1997	26,908,231	27,892,388	27,310,569	27,601,479
1998	27,078,631	27,486,776	25,963,527	26,725,151
1999	27,667,159	27,655,530	27,727,955	27,691,742
2000	--	28,242,988	28,890,145	28,566,567
2001	--	28,818,167	28,999,111	28,908,639
2002	--	29,392,686	29,012,758	29,202,722
2003	--	29,966,545	29,338,263	29,652,404
2004	--	30,539,746	29,796,778	30,168,262
2005	--	31,112,288	30,016,438	30,564,363
2006	--	31,684,173	29,997,933	30,841,053
2007	--	32,255,402	29,832,200	31,043,801
2008	--	32,825,975	29,696,295	31,261,135
2009	--	33,395,893	29,666,724	31,531,308
2010	--	33,965,156	29,738,479	31,851,818
2011	--	34,533,766	29,843,132	32,188,449
2012	--	35,101,723	29,920,323	32,511,023
2013	--	35,669,028	29,946,149	32,807,588
2014	--	36,235,682	29,937,088	33,086,385
2015	--	36,801,685	29,923,989	33,362,837
2016	--	37,367,038	29,929,179	33,648,108
2017	--	37,931,743	29,955,787	33,943,765
2018	--	38,495,799	29,993,163	34,244,481
2019	--	39,059,207	30,028,044	34,543,626
2020	--	39,621,969	30,053,513	34,837,741
Root Mean Square Error		0.04907		

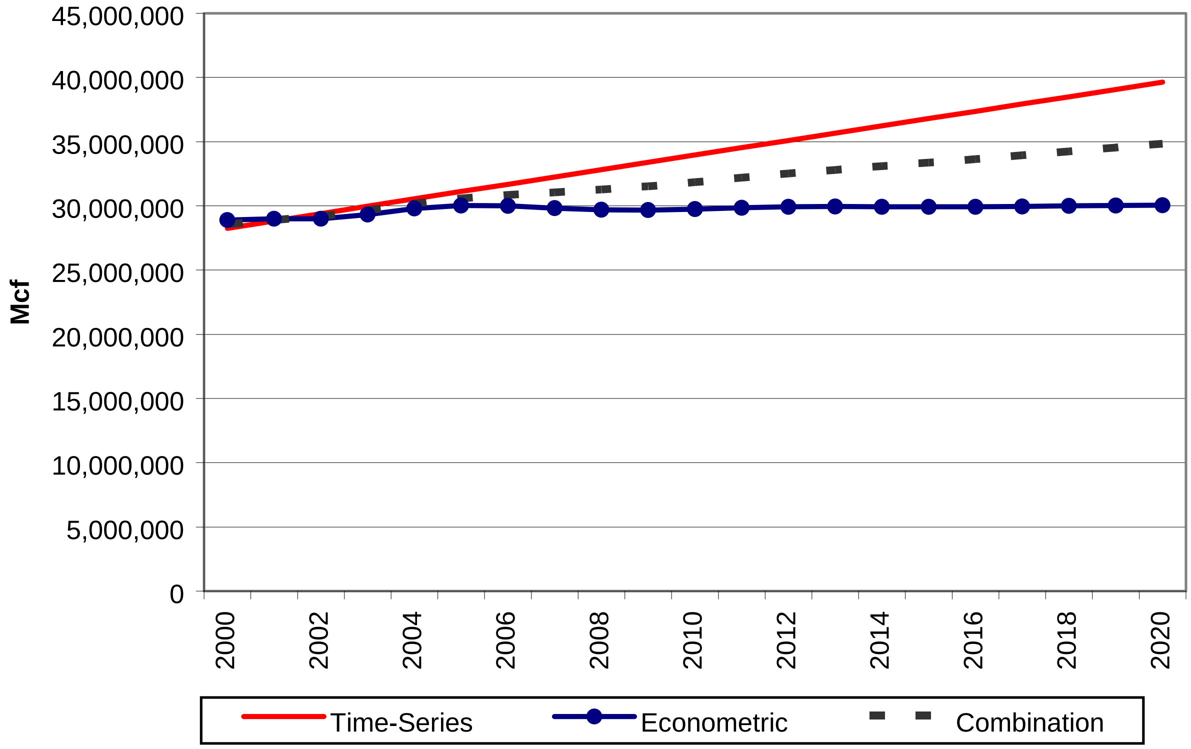

Figure 4.2: Commercial Baseline Demand Forecast (2000-2020)

4.3: Industrial Baseline Forecast

The results from the industrial in-state demand forecast are presented in Table 4.3. A graph of these longer run trends is presented in Figure 4.3. Our forecast assumes no greater than average growth in either the number of industrial customers, or their average usage. In addition, the baseline forecast assumes that current economic conditions and prices will hold relatively stable.

The average annual rate of growth for industrial natural gas usage over the forecast period is half of one percent. Industrial natural gas usage is forecast to grow from a 1999 level of 74 Bcf to a 2020 forecast level of 81 Bcf.

Given the relatively limited historic growth of industrial customers and usage, our forecast for future use is somewhat limited. We anticipate relatively constant growth, under baseline conditions, for industrial consumption. The addition of new industrial customers, however, could impact this forecast. In later chapters of this report, we examine the addition of new industries to Alaska and their implications for industrial and large volume customer usage. Sensitivities to our baseline forecast are also considered in the subsequent chapter.

Table 4.3: Industrial Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time-Series (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	60,438,785	65,983,516	60,953,186	63,468,351
1987	67,467,489	66,711,763	70,090,074	68,400,918
1988	67,804,860	67,440,010	68,568,283	68,004,146
1989	59,341,410	68,168,256	73,723,646	70,945,951
1990	76,849,333	68,896,503	73,991,984	71,444,243
1991	75,637,177	69,624,750	74,064,575	71,844,662
1992	80,937,950	70,352,997	70,766,558	70,559,778
1993	75,794,979	71,081,244	69,802,135	70,441,689
1994	61,404,028	71,809,491	67,148,789	69,479,140
1995	64,977,342	72,537,737	71,056,370	71,797,053
1996	75,616,070	73,265,984	70,741,268	72,003,626
1997	73,599,299	73,994,231	71,538,235	72,766,233
1998	75,946,906	74,722,478	73,864,793	74,293,635
1999	74,224,056	75,450,725	70,231,772	72,841,248
2000	--	76,178,972	70,298,379	73,238,676
2001	--	76,907,218	70,365,044	73,636,131
2002	--	77,635,465	70,431,784	74,033,625
2003	--	78,363,712	70,498,588	74,431,150
2004	--	79,091,959	70,565,442	74,828,701
2005	--	79,820,206	70,632,373	75,226,290
2006	--	80,548,453	70,699,354	75,623,904
2007	--	81,276,699	70,766,412	76,021,556
2008	--	82,004,946	70,833,520	76,419,233
2009	--	82,733,193	70,900,705	76,816,949
2010	--	83,461,440	70,967,941	77,214,690
2011	--	84,189,687	71,035,253	77,612,470
2012	--	84,917,933	71,102,616	78,010,275
2013	--	85,646,180	71,170,057	78,408,118
2014	--	86,374,427	71,237,547	78,805,987
2015	--	87,102,674	71,305,116	79,203,895
2016	--	87,830,921	71,372,748	79,601,835
2017	--	88,559,168	71,440,431	79,999,800
2018	--	89,287,414	71,508,192	80,397,803
2019	--	90,015,661	71,576,003	80,795,832
2020	--	90,743,908	71,643,893	81,193,900
Root Mean Square Error		0.10026		

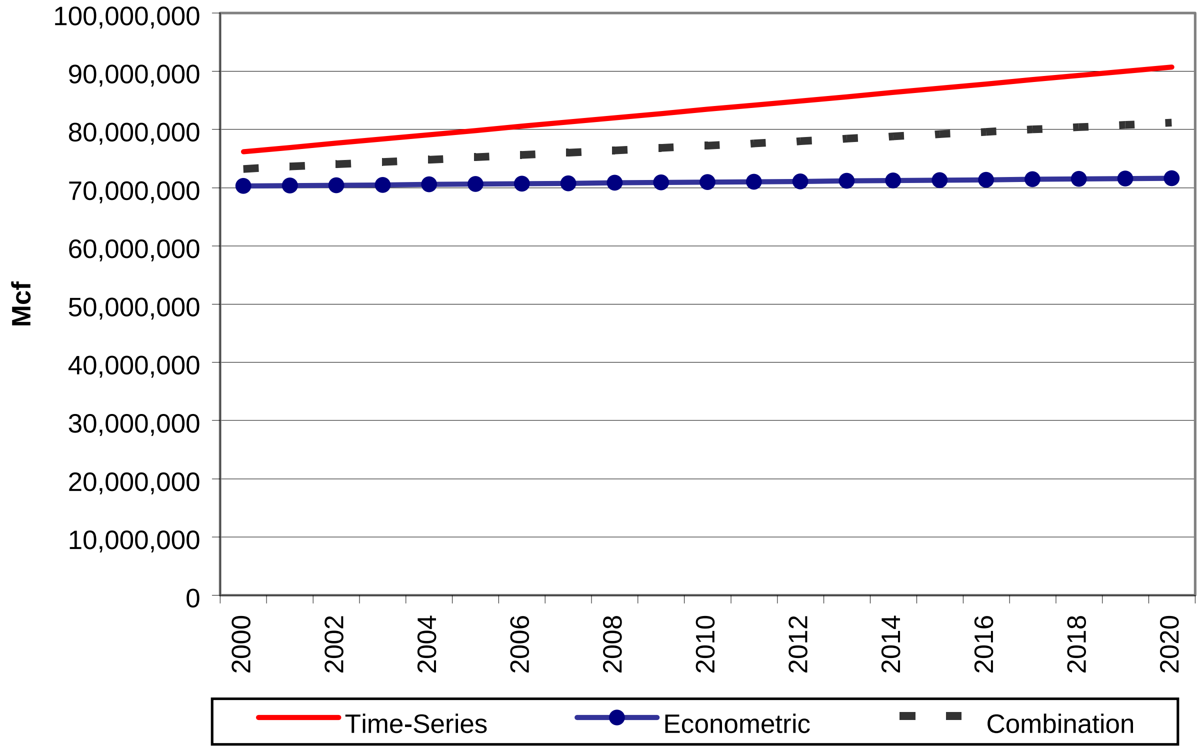

Figure 4.3: Industrial Baseline Demand Forecast (2000-2020)

4.4: Electric Utility Baseline Forecast

Our electric utility demand model was prepared in a manner different from than the other customer classes. First, we developed a long run trend forecast of power generation for Alaska's electric utilities. Second, we used the long run average trend for the gas-fired portion of the fuel mix to determine what proportion of that generation would come from gas-fired units. Third, we utilized the long run trend in power plant heat rates to estimate the future operating efficiency of total in-state power generation. This efficiency rating allows us to estimate the amount of natural gas that would be used for power generation under business as usual conditions. The forecast assumes that no new power generation facilities will be brought on line during the forecast period.

The results from the baseline electric utility demand forecast can be found in Table 4.4 while a graph of forecast electric utility natural gas usage has been provided in Figure 4.4. Baseline forecast electric utility usage is anticipated to grow from a level of 31 Bcf in 1999 to 41 Bcf by the year 2020. Sensitivities to this forecast are also considered in the following chapter of this report.

Table 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time-Series (Mcf)
1986	34,409,000	33,670,793
1987	30,530,000	31,234,619
1988	30,841,000	31,418,047
1989	32,746,000	32,312,018
1990	34,366,142	33,549,084
1991	31,329,758	32,470,899
1992	28,953,390	31,259,209
1993	28,024,737	27,867,045
1994	29,047,703	28,129,752
1995	29,808,627	28,661,334
1996	31,154,273	29,541,429
1997	33,509,748	31,362,521
1998	28,784,955	30,332,479
1999	30,527,841	32,409,397
2000	--	35,656,886
2001	--	32,949,652
2002	--	33,655,948
2003	--	34,119,758
2004	--	34,899,977
2005	--	35,406,497
2006	--	35,330,693
2007	--	35,813,699
2008	--	36,248,792
2009	--	36,677,751
2010	--	37,031,714
2011	--	37,353,364
2012	--	37,759,602
2013	--	38,149,476
2014	--	38,529,726
2015	--	38,899,627
2016	--	39,272,923
2017	--	39,657,179
2018	--	40,036,768
2019	--	40,414,176
2020	--	40,790,982

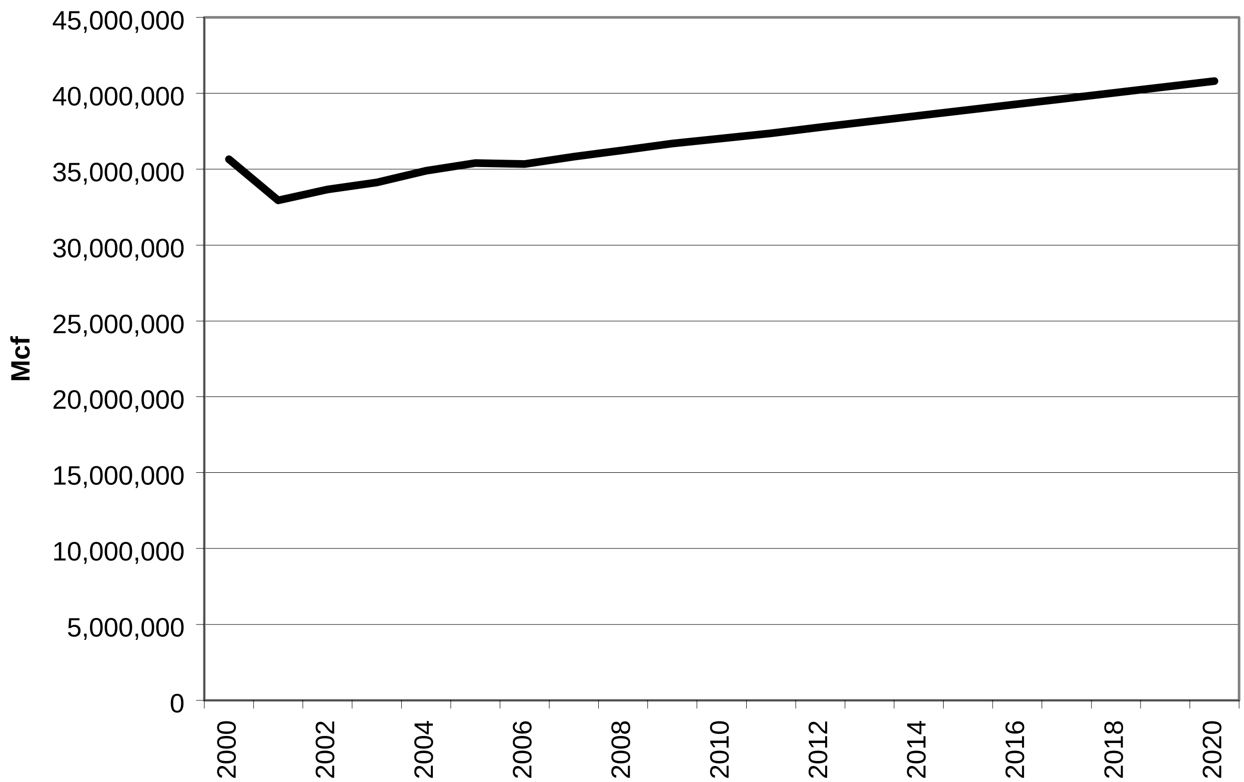

Figure 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

4.5: Total Forecast Baseline In-State Demand

The aggregation of our baseline forecasts for each customer class can be summed to analyze total in-state demand until 2020 under business as usual conditions. The total baseline forecast is developed from our combination forecast. Total in-state, baseline usage, is presented in Table 4.5, while Figure 4.6 presents a graphical representation of annual baseline usage levels.

We anticipate that baseline forecast natural gas usage over the forecast period will grow by 27 Bcf. Residential customers will account for 24 percent of this growth, commercial customers will account for 22 percent of this growth, industrial customers will account for 22 percent of this growth, and electricity utilities will account for 32 percent of this growth. Sensitivities to the overall baseline forecast, and total forecast use by the year 2020, are explored in the next chapter of our report.

Table 4.5: Total In-State Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Baseline (Mcf)
1986	127,812,794	130,209,467
1987	130,477,912	133,547,658
1988	132,017,041	132,977,591
1989	127,414,589	137,916,372
1990	147,002,211	140,758,213
1991	141,426,123	139,104,881
1992	145,540,558	137,386,059
1993	137,679,939	133,585,145
1994	126,044,789	133,790,300
1995	134,995,724	138,465,219
1996	150,264,501	143,815,443
1997	149,163,394	147,416,112
1998	147,427,109	147,489,931
1999	150,052,920	150,117,221
2000	--	154,980,358
2001	--	153,334,730
2002	--	155,061,745
2003	--	156,708,696
2004	--	158,745,146
2005	--	160,395,253
2006	--	161,350,851
2007	--	162,798,743
2008	--	164,220,859
2009	--	165,697,439
2010	--	167,157,253
2011	--	168,608,985
2012	--	170,139,507
2013	--	171,636,103
2014	--	173,113,957
2015	--	174,587,941
2016	--	176,083,191
2017	--	177,608,996
2018	--	179,144,660
2019	--	180,686,203
2020	--	182,232,010

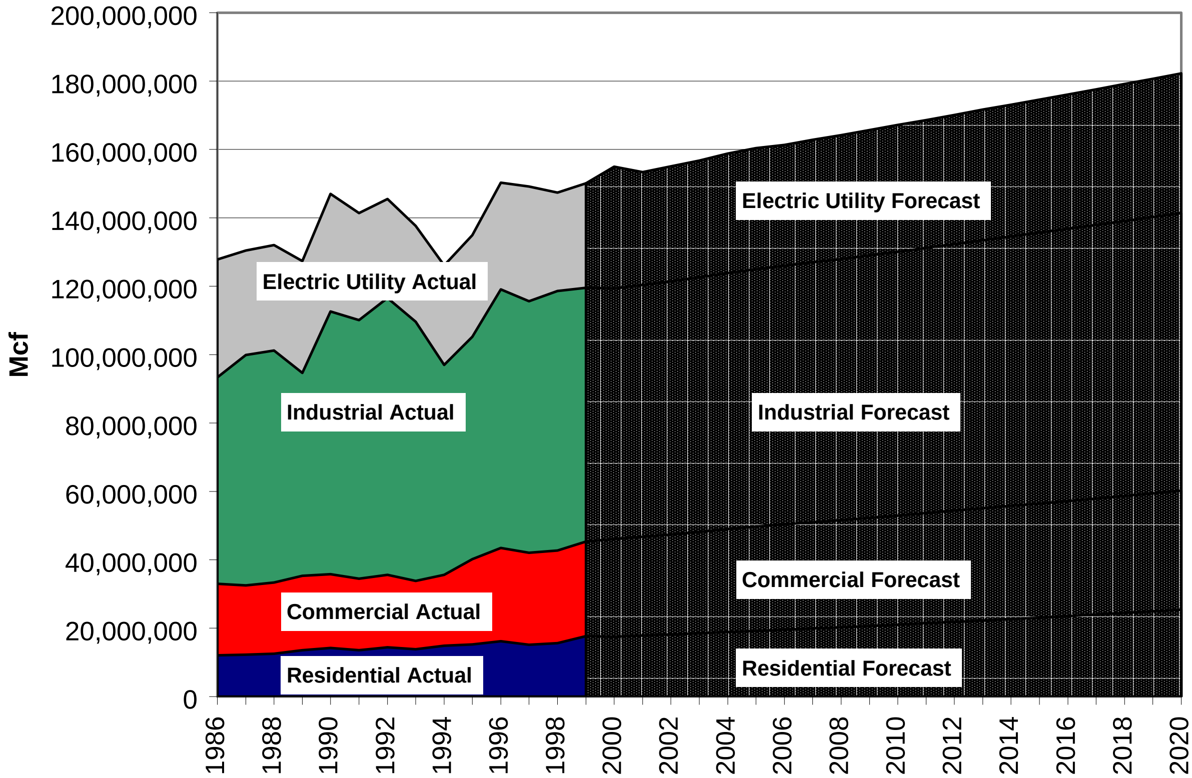

Figure 4.5: Total In-State Natural Gas Usage, Baseline Forecast (2000-2020)

CHAPTER 5: SENSITIVITY ANALYSIS OF BASELINE FORECAST

Our sensitivity analyses consisted of examining potential variations to our baseline forecast under varying economic assumptions. We examined two different scenario categories that could impact customer class natural gas usage: changes in prices; and changes in income. Specifically, each customer class baseline forecast was subject to the following scenarios:

(1) High Price Scenario: customer class natural gas prices were assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period.

(2) Low Price Scenario: customer class natural gas prices were assumed to decrease at an annual average rate of one percent, in real dollars, over the forecast period.

(3) High Income Scenario: state personal income was assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period. Gross state manufacturing product, the income proxy used for our industrial models, is assumed to increase by one percent per year as well.

(4) Low Income Scenario: state personal income was assumed to grow at an average annual rate of zero percent, in real dollars, over the forecast period. Gross state manufacturing product was also assumes to be constant in real dollars.

Our baseline assumptions are comparable to estimates prepared by the University of Alaska's Institute for Economic and Social Research (ISER). The most recent ISER base case forecast anticipates statewide average personal income growth of around one percent until the year 2020. Low personal income growth scenarios used in the ISER models utilize a 0.62 percent average annual growth rate, while the high personal income growth scenario is 2.13.[1]

5.1: Residential Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that residential natural gas usage will increase from an annual level of approximately 17.5 Bcf in 2000 to a level of 21 Bcf in 2010. The increase at the end of the forecast period, 2020, is anticipated to be 25.4 Bcf. The total increase in residential natural gas usage over the ten year period is anticipated to be 3.5 Bcf and 7.9 Bcf for the twenty year period. This represents approximately a 20 percent increase over the ten year period

[1]Scott Goldsmith. *Economic Projects for Alaska and the Southern Railbelt: 2000-2025*. Anchorage: Institute of Social and Economic Research, October 3, 2001. Pages 2, 47, and 65.

and 45 percent increase over the twenty year period. The annual average rate of growth under the baseline forecast is 1.8 percent.

As noted earlier, we subjected each of our customer class forecasts to a number of sensitivities to measure the potential shift in usage that could result from either price or income swings. A comparison of the forecast residential usage levels under our various price scenarios are in Table 5.1.

Under our high natural gas price scenario, we estimate lower levels of residential natural gas usage (holding other variables constant). Under a high natural gas price scenario, residential annual natural gas usage will grow from a level of 17.5 Bcf in 2000 to a level of 20.7 Bcf in 2010 to a level of 24.7 Bcf in 2020.

Total residential usage during the forecast period is anticipated to grow at a slower rate than the baseline forecast. Overall, we anticipate a 1.7 percent annual average rate of growth if the longer run price decrease trend is dampened. Over a 10 year period (2000-2010) we anticipate residential natural gas usage to grow by 3.2 Bcf, and by 7.2 Bcf over the twenty year long run forecast period (2000-2020). This represents an 18.4 percent and 41.2 percent increase over the short run (2000-2010) and long run (2000-2020) forecast periods, respectively.

We also examined a scenario where natural gas prices fell at a greater rate than our baseline forecast. Under our low natural gas price scenario, there would be slightly greater residential natural gas usage. Under our low price scenario, we anticipate residential natural gas usage to grow at an annual average rate of 2 percent. During the short run period, this usage would grow by approximately 3.9 Bcf, and by 8.6 Bcf over the long run horizon.

Table 5.1: Forecast Residential Natural Gas Usage Under Different Price Scenarios

Year	Residential Base Case (Mcf)	Residential High Price Case (Mcf)	Residential Low Price Case (Mcf)
2000	17,518,229	17,500,093	17,536,585
2001	17,840,308	17,794,479	17,886,835
2002	18,169,451	18,095,331	18,244,930
2003	18,505,384	18,402,367	18,610,612
2004	18,848,207	18,715,675	18,983,999
2005	19,198,104	19,035,431	19,365,289
2006	19,555,201	19,361,751	19,754,627
2007	19,919,686	19,694,810	20,152,221
2008	20,291,698	20,034,739	20,558,223
2009	20,671,431	20,381,722	20,972,847
2010	21,059,031	20,735,890	21,396,261
2011	21,454,701	21,097,441	21,828,684
2012	21,858,607	21,466,526	22,270,300
2013	22,270,920	21,843,304	22,721,302
2014	22,691,858	22,227,984	23,181,928
2015	23,121,582	22,620,716	23,652,356
2016	23,560,325	23,021,717	24,132,845
2017	24,008,252	23,431,145	24,623,578
2018	24,465,608	23,849,231	25,124,821
2019	24,932,570	24,276,139	25,636,776
2020	25,409,386	24,712,105	26,159,711
Ten Year Increase	3,540,802	3,235,797	3,859,676
Twenty Year Increase	7,891,157	7,212,012	8,623,126

If state personal income were to increase above its past five year rates, we see significant opportunities for residential natural gas usage growth. Under our high income assumption, residential natural gas usage will increase from a level of 17.6 Bcf in 2000 to 21.9 Bcf in 2010 to 27.3 Bcf in 2020. This represents a 24.7 percent increase over the short run forecast period, and a 55.5 percent increase over the longer run forecast period. Under the high income scenario, residential natural gas usage would be approximately 1.9 Bcf above the long run baseline estimated growth levels. However, some caution should be given to these results. In order for these usage levels to be obtained, economic growth would have to remain uncharacteristically high over the entire forecast period.

The implication of low-income growth on residential natural gas usage over the different forecast periods is summarized in Table 5.2. Under the low-income assumptions, we anticipate much lower levels of natural gas usage. The average annual rate of growth during the forecast period would be approximately 1.6 percent. Total usage over the short run period (10 years) would increase by 2.8 Bcf, and by 6.3 Bcf over the long run forecast horizon.

The residential usage levels associated with different income levels are in Table 5.2.

Table 5.2: Forecast Residential Natural Gas Usage Under Different Income Scenarios

Year	Residential Base Case (Mcf)	Residential High Income Case (Mcf)	Residential Low Income Case (Mcf)
2000	17,518,229	17,584,947	17,451,674
2001	17,840,308	17,975,876	17,706,062
2002	18,169,451	18,376,091	17,966,365
2003	18,505,384	18,785,358	18,232,270
2004	18,848,207	19,203,831	18,503,889
2005	19,198,104	19,631,736	18,781,361
2006	19,555,201	20,069,301	19,064,823
2007	19,919,686	20,516,715	19,354,420
2008	20,291,698	20,974,220	19,650,301
2009	20,671,431	21,442,059	19,952,614
2010	21,059,031	21,920,440	20,261,517
2011	21,454,701	22,409,617	20,577,167
2012	21,858,607	22,909,852	20,899,726
2013	22,270,920	23,421,367	21,229,362
2014	22,691,858	23,944,434	21,566,245
2015	23,121,582	24,479,334	21,910,548
2016	23,560,325	25,026,305	22,262,453
2017	24,008,252	25,585,635	22,622,141
2018	24,465,608	26,157,632	22,989,802
2019	24,932,570	26,742,544	23,365,628
2020	25,409,386	27,340,683	23,749,813
Ten Year Increase	3,540,802	4,335,493	2,809,844
Twenty Year Increase	7,891,157	9,755,736	6,298,140

5.2: Commercial Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that commercial natural gas usage will increase from an annual level of approximately 28.6 Bcf (2000) to 31.9 Bcf (2010) to 34.8 Bcf (2020). The total increase in commercial natural gas usage over this period is 3.3 Bcf (2000-2010) and 6.3 Bcf. Over the long run forecast period, we anticipate annual average growth to be one percent. This is consistent with historic trends when one out-lying year (1994-1995) is excluded from analysis.

Under our high price scenario, we estimate much lower levels of commercial natural gas usage. Our high commercial natural gas price scenario forecasts annual use to grow from a level of 28.5 Bcf in 2000 to 29.6 Bcf in 2010 and 30.7 Bcf in 2020. The annual average rate of growth during the period is less than one half percent. Total commercial usage over the forecast period, under our high natural gas price assumption, will grow by 1.1 Bcf over the short run forecast period (2000-2010) and by 2.2 Bcf over the longer run forecast period (2000-2020). For the year 2010, this would represent a 3.9 percent increase in commercial natural gas usage over the short run period and a 7.8 percent increase over the longer run period. Under our high price assumption, usage would be approximately 2.2 Bcf below the baseline short run forecast estimate and 4 Bcf over the longer run forecast period. The changes associated with each of our different price scenario forecasts are presented in Table 5.3.

Table 5.3: Forecast Commercial Natural Gas Usage Under Different Price Scenarios

Year	Commercial Base Case (Mcf)	Commercial High Price Case (Mcf)	Commercial Low Price Case (Mcf)
2000	28,566,567	28,451,442	28,683,799
2001	28,908,639	28,602,525	29,224,552
2002	29,202,722	28,671,009	29,760,330
2003	29,652,404	28,890,366	30,464,513
2004	30,168,262	29,170,069	31,249,292
2005	30,564,363	29,336,492	31,915,682
2006	30,841,053	29,395,288	32,457,978
2007	31,043,801	29,392,036	32,921,074
2008	31,261,135	29,407,258	33,402,273
2009	31,531,308	29,473,177	33,946,905
2010	31,851,818	29,585,393	34,555,030
2011	32,188,449	29,713,250	35,188,542
2012	32,511,023	29,831,304	35,811,692
2013	32,807,588	29,930,419	36,408,946
2014	33,086,385	30,018,098	36,989,250
2015	33,362,837	30,107,039	37,571,398
2016	33,648,108	30,205,861	38,169,861
2017	33,943,765	30,315,356	38,787,369
2018	34,244,481	30,431,127	39,417,553
2019	34,543,626	30,548,081	40,051,786
2020	34,837,741	30,663,720	40,685,286
Ten Year Increase	3,285,251	1,133,951	5,871,231
Twenty Year Increase	6,271,174	2,212,278	12,001,487

Under our low price forecast, commercial natural gas usage would increase considerably given this class' strong price sensitivity (i.e., price elasticity of demand). The average annual rate of growth under our low price scenario is well over 1.5 percent per year. Over the short run forecast period, commercial usage will grow by 5.9 Bcf and almost 12 Bcf over the longer run forecast period.

Table 5.4: Forecast Commercial Natural Gas Usage Under Different Income Scenarios

Year	Commercial Base Case (Mcf)	Commercial High Income Case (Mcf)	Commercial Low Income Case (Mcf)
2000	28,566,567	28,576,984	28,532,498
2001	28,908,639	28,929,557	29,150,269
2002	29,202,722	29,234,126	29,474,563
2003	29,652,404	29,694,762	29,803,121
2004	30,168,262	30,222,057	30,103,978
2005	30,564,363	30,629,414	30,387,626
2006	30,841,053	30,916,930	30,668,380
2007	31,043,801	31,130,068	30,951,703
2008	31,261,135	31,357,778	31,237,019
2009	31,531,308	31,638,622	31,522,587
2010	31,851,818	31,970,191	31,807,560
2011	32,188,449	32,318,083	32,091,903
2012	32,511,023	32,651,874	32,375,815
2013	32,807,588	32,959,461	32,659,420
2014	33,086,385	33,249,113	32,942,736
2015	33,362,837	33,536,403	33,225,744
2016	33,648,108	33,832,619	33,508,427
2017	33,943,765	34,139,374	33,790,782
2018	34,244,481	34,451,290	34,072,809
2019	34,543,626	34,761,652	34,354,512
2020	34,837,741	35,066,944	34,635,893
Ten Year Increase	3,285,251	3,393,207	3,275,062
Twenty Year Increase	6,271,174	6,489,961	6,103,395

Table 5.4 presents our forecast sensitivity analysis for changes in commercial usage resulting from different assumptions of future economic activity. Higher sustained economic growth in the state could result in the growth of commercial natural gas usage, holding other factors constant. As seen in the table, under a high income scenario, commercial natural gas usage would increase by 22.7 percent over the long run forecast period and by approximately 22.4 percent under a low income scenario.

5.3: Industrial Baseline Forecast Sensitivity

Under our baseline forecast, we anticipate that industrial natural gas usage will grow at a relatively slow pace. Customer growth and usage in this class has been relatively constant over the recent past, and without the addition of new industries, it seems unlikely that there would be a significant relative shift in industrial usage. However, despite the relatively low percent growth for industrial use, it is a meaningful amount in absolute levels.

Table 5.5: Forecast Industrial Natural Gas Usage Under Different Price Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Price Case (Mcf)	Industrial Low Price Case (Mcf)
2000	73,238,676	73,197,507	73,280,303
2001	73,636,131	73,553,767	73,719,514
2002	74,033,625	73,910,037	74,158,897
2003	74,431,150	74,266,303	74,598,436
2004	74,828,701	74,622,570	75,038,129
2005	75,226,290	74,978,844	75,477,994
2006	75,623,904	75,335,110	75,918,010
2007	76,021,556	75,691,388	76,358,194
2008	76,419,233	76,047,661	76,798,539
2009	76,816,949	76,403,938	77,239,049
2010	77,214,690	76,760,215	77,679,715
2011	77,612,470	77,116,500	78,120,555
2012	78,010,275	77,472,776	78,561,547
2013	78,408,118	77,829,065	79,002,711
2014	78,805,987	78,185,348	79,444,037
2015	79,203,895	78,541,636	79,885,529
2016	79,601,835	78,897,930	80,327,188
2017	79,999,800	79,254,219	80,769,008
2018	80,397,803	79,610,512	81,210,997
2019	80,795,832	79,966,805	81,653,146
2020	81,193,900	80,323,106	82,095,472
Ten Year Increase	3,976,015	3,562,708	4,399,411
Twenty Year Increase	7,955,225	7,125,599	8,815,169

Under our baseline forecast, we anticipate industrial usage to grow around 1 percent per year. For the short run forecast period (2000-2010), this would entail about a 5.4 percent increase or 4 Bcf. Over the long run forecast period we anticipate baseline growth of about 8 Bcf – or about an 11 percent increase. If prices increase, we forecast industrial natural gas usage growth would decrease slightly. Alternatively, should prices decrease, industrial natural gas usage would increase slightly.

We also considered the impact of changing economic conditions on industrial usage patterns in Alaska. Under most income scenarios, there are limited shifts in industrial usage over both the short run and longer run forecasting horizon. Given the relatively steady baseline forecast, changes in our differing income assumptions (as well as price) typically result in level shifts in usage.

Table 5.6: Forecast Industrial Natural Gas Usage Under Different Income Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Income Case (Mcf)	Industrial Low Income Case (Mcf)
2000	73,238,676	73,271,847	73,205,369
2001	73,636,131	73,702,568	73,569,492
2002	74,033,625	74,133,416	73,933,615
2003	74,431,150	74,564,396	74,297,739
2004	74,828,701	74,995,497	74,661,862
2005	75,226,290	75,426,724	75,025,986
2006	75,623,904	75,858,085	75,390,109
2007	76,021,556	76,289,566	75,754,232
2008	76,419,233	76,721,175	76,118,356
2009	76,816,949	77,152,918	76,482,479
2010	77,214,690	77,584,783	76,846,603
2011	77,612,470	78,016,776	77,210,726
2012	78,010,275	78,448,903	77,574,849
2013	78,408,118	78,881,154	77,938,973
2014	78,805,987	79,313,533	78,303,096
2015	79,203,895	79,746,048	78,667,220
2016	79,601,835	80,178,686	79,031,343
2017	79,999,800	80,611,453	79,395,467
2018	80,397,803	81,044,357	79,759,590
2019	80,795,832	81,477,384	80,123,713
2020	81,193,900	81,910,542	80,487,837
Ten Year Increase	3,976,015	4,312,935	3,641,234
Twenty Year Increase	7,955,225	8,638,695	7,282,468

5.4: Electric Utility Baseline Forecast Sensitivity

We also examined a number of different scenarios for power generation. Our sensitivity analysis of power generation differed somewhat from the analysis done for retail natural gas usage for residential, commercial, and industrial customers. Our sensitivities were based upon changes that our economic drivers (price, income) had on electricity usage. From there we forecast the changes associated with gas fired power generation, and natural gas usage.

Table 5.7: Forecast Electric Utility Natural Gas Usage Under Different Price Scenarios

Year	Estimated Utility Base Case (Mcf)	Estimated Utility High Price Case (Mcf)	Estimated Utility Low Price Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	32,125,910	33,773,393
2002	33,655,948	32,814,549	34,497,347
2003	34,119,758	33,266,764	34,972,752
2004	34,899,977	34,027,477	35,772,476
2005	35,406,497	34,521,334	36,291,659
2006	35,330,693	34,447,426	36,213,961
2007	35,813,699	34,918,357	36,709,042
2008	36,248,792	35,342,572	37,155,012
2009	36,677,751	35,760,807	37,594,694
2010	37,031,714	36,105,921	37,957,507
2011	37,353,364	36,419,530	38,287,198
2012	37,759,602	36,815,612	38,703,592
2013	38,149,476	37,195,739	39,103,213
2014	38,529,726	37,566,483	39,492,969
2015	38,899,627	37,927,136	39,872,118
2016	39,272,923	38,291,100	40,254,746
2017	39,657,179	38,665,750	40,648,609
2018	40,036,768	39,035,849	41,037,687
2019	40,414,176	39,403,821	41,424,530
2020	40,790,982	39,771,208	41,810,757
Ten Year Increase	1,374,828	536,020	2,387,606
Twenty Year Increase	5,134,096	4,201,307	6,240,856

Table 5.7 presents the results from our electric utility baseline demand sensitivity analysis for changes in retail electricity prices. Under our baseline scenario, we

anticipate electric generation demand for natural gas to grow during the short run forecast period at approximately 3.9 percent. Over the longer run, we forecast generation use of natural gas to grow by about 14.4 percent.

If retail electricity prices increase by one percent, in real dollars, per year, we anticipate a slowing of electricity demand, and as a result, natural gas fired generation. The short run increase in power generation usage of natural gas falls to 1.51 percent under our high price scenario, and to 11.8 percent over the longer run forecast period.

Under a low retail electricity price scenario, we see moderate growth in the amount of natural gas fired generation. Over the short run period, this increase is about 6.7 percent, while over the longer run there is approximately at 17.5 percent increase in natural gas demanded by electric generators.

We have also examined the potential changes in natural gas fired power generation from shifts in our underlying economic output assumptions. If state income were to grow by one percent, in real dollars, per year, we forecast a relatively significant amount of gas fired power generation. Gas usage by power generation increase by about 14.5 percent over a ten year period, and 26.1 percent over the longer forecast period, assuming relatively strong economic growth.

Alternatively, if economic growth were to proceed on a relatively flat pace, we see power generation dipping in the short run, but rebounding slightly over the long run forecast period. In the short run, we forecast natural gas usage to fall by about 6.3 percent. Gas usage by power generation would increase over the longer run, but at a very moderate rate (3.2 percent).

Table 5.8: Forecast Electric Utility Natural Gas Usage Under Different Income Scenarios

Year	Estimated Utility Base Case (Mcf))	Estimated Utility High Income Case (Mcf)	Estimated Utility Low Income Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	36,244,617	29,654,687
2002	33,655,948	37,021,543	30,290,353
2003	34,119,758	37,531,734	30,707,782
2004	34,899,977	38,389,974	31,409,979
2005	35,406,497	38,947,146	31,865,847
2006	35,330,693	38,863,763	31,797,624
2007	35,813,699	39,395,069	32,232,329
2008	36,248,792	39,873,671	32,623,913
2009	36,677,751	40,345,526	33,009,975
2010	37,031,714	40,734,885	33,328,543
2011	37,353,364	41,088,701	33,618,028
2012	37,759,602	41,535,562	33,983,642
2013	38,149,476	41,964,424	34,334,529
2014	38,529,726	42,382,699	34,676,754
2015	38,899,627	42,789,590	35,009,664
2016	39,272,923	43,200,216	35,345,631
2017	39,657,179	43,622,897	35,691,462
2018	40,036,768	44,040,445	36,033,091
2019	40,414,176	44,455,593	36,372,758
2020	40,790,982	44,870,081	36,711,884
Ten Year Increase	1,374,828	5,164,984	-2,241,358
Twenty Year Increase	5,134,096	9,300,180	1,141,983

5.5: Total Usage Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that total natural gas usage will increase from an annual level of approximately 155 Bcf (2000) to 182 Bcf (2020). The total increase in total natural gas usage over this period is 27 Bcf. For the year 2020, this increase represents a 17.6 percent increase from its 1999 levels under our baseline forecast.

If natural gas prices were to increase at an annual average rate of one percent, we estimate much lower levels of total natural gas usage. Our high price case estimates annual use to grow from a level of 155 Bcf in 2000 to a level of 175 Bcf in 2020. Total usage over the forecast period, under our high natural gas price assumption, will grow by 20.8 Bcf over the forecast period. For the year 2020, this would represent a 13.4 percent increase in total natural gas usage. Under our high price assumption, usage would be approximately 6.5 Bcf below the baseline estimate.

If natural gas prices were to decrease at an annual average rate of one percent over the forecast period, we estimate higher total natural gas usage. Our low price forecast for total natural gas usage is 155 Bcf in 2000, and grows to a level of 191 Bcf by the year 2020. This represents an increase of 35.6 Bcf over 2000 total usage levels – or a 23 percent increase. Under our low price scenario, total natural gas usage will be approximately 8.4 Bcf above its baseline level.

Table 5.9: Forecast In-State Natural Gas Usage Under Different Price Scenarios

Year	Estimated Total Base Case (Mcf)	Estimated Total High Price Case (Mcf)	Estimated Total Low Price Case (Mcf)
2000	154,980,358	154,718,943	155,070,588
2001	153,334,730	152,076,681	154,604,295
2002	155,061,745	153,490,926	156,661,503
2003	156,708,696	154,825,800	158,646,312
2004	158,745,146	156,535,791	161,043,895
2005	160,395,253	157,872,101	163,050,624
2006	161,350,851	158,539,575	164,344,576
2007	162,798,743	159,696,591	166,140,531
2008	164,220,859	160,832,230	167,914,047
2009	165,697,439	162,019,644	169,753,495
2010	167,157,253	163,187,419	171,588,512
2011	168,608,985	164,346,721	173,424,979
2012	170,139,507	165,586,218	175,347,131
2013	171,636,103	166,798,526	177,236,172
2014	173,113,957	167,997,914	179,108,184
2015	174,587,941	169,196,528	180,981,401
2016	176,083,191	170,416,609	182,884,641
2017	177,608,996	171,666,470	184,828,565
2018	179,144,660	172,926,720	186,791,058
2019	180,686,203	174,194,846	188,766,237
2020	182,232,010	175,470,138	190,751,225
Ten Year Increase	12,176,895	8,468,477	16,517,924
Twenty Year Increase	27,251,652	20,751,195	35,680,637

If state personal income were to increase at one percent per year, we forecast opportunities for total natural gas usage growth. Under our high income assumption, total natural gas usage will increase from a level of 155 Bcf in 2000 to 189 Bcf in 2020. This represents a 22.1 percent increase over the forecast period. Under the high income scenario, total natural gas usage would be approximately 6.9 Bcf above the baseline estimated growth levels.

If state personal income were to remain constant over the forecast period, total natural gas usage growth would grow by about 6.4 Bcf less than the baseline estimate. Under our low income assumption, total natural gas usage will grow from a level of 155 Bcf in 2000 to 176 Bcf in 2020. This represents a 13.5 percent increase over the forecast period.

Table 5.10: Forecast In-State Natural Gas Usage Under Different Income Scenarios

Year	Estimated Total Base Case (Mcf)	Estimated Total High Income Case (Mcf)	Estimated Total Low Income Case (Mcf)
2000	154,980,358	155,003,678	154,759,441
2001	153,334,730	156,852,618	150,080,509
2002	155,061,745	158,765,176	151,664,896
2003	156,708,696	160,576,250	153,040,912
2004	158,745,146	162,811,359	154,679,708
2005	160,395,253	164,635,020	156,060,819
2006	161,350,851	165,708,078	156,920,937
2007	162,798,743	167,331,417	158,292,685
2008	164,220,859	168,926,844	159,629,589
2009	165,697,439	170,579,124	160,967,656
2010	167,157,253	172,210,299	162,244,222
2011	168,608,985	173,833,176	163,497,824
2012	170,139,507	175,546,192	164,834,032
2013	171,636,103	177,226,405	166,162,283
2014	173,113,957	178,889,779	167,488,831
2015	174,587,941	180,551,375	168,813,176
2016	176,083,191	182,237,825	170,147,855
2017	177,608,996	183,959,360	171,499,851
2018	179,144,660	185,693,724	172,855,292
2019	180,686,203	187,437,174	174,216,611
2020	182,232,010	189,188,250	175,585,427
Ten Year Increase	12,176,895	17,206,621	7,484,781
Twenty Year Increase	27,251,652	34,184,572	20,825,986

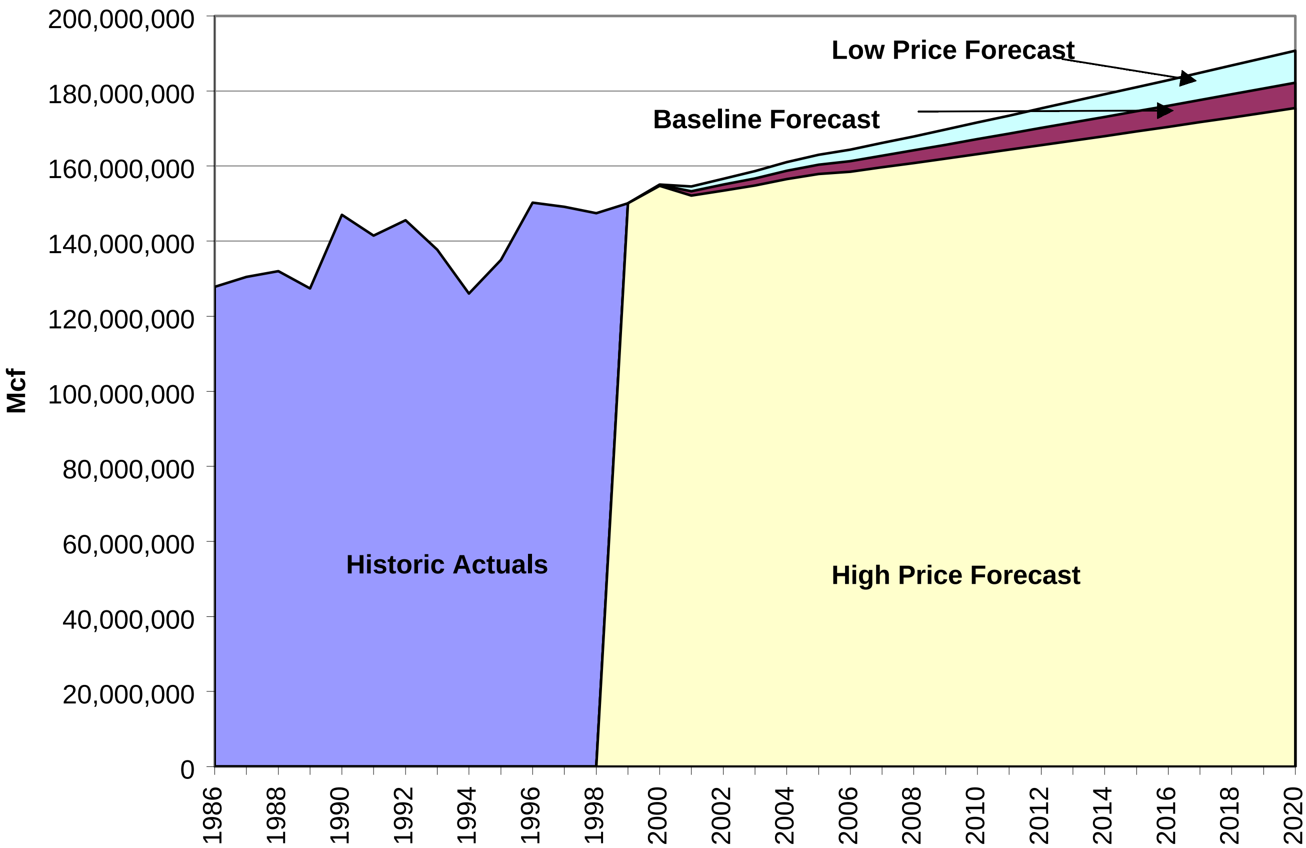

Figure 5.1: Forecast In-State Natural Gas Usage Under Different Price Scenarios

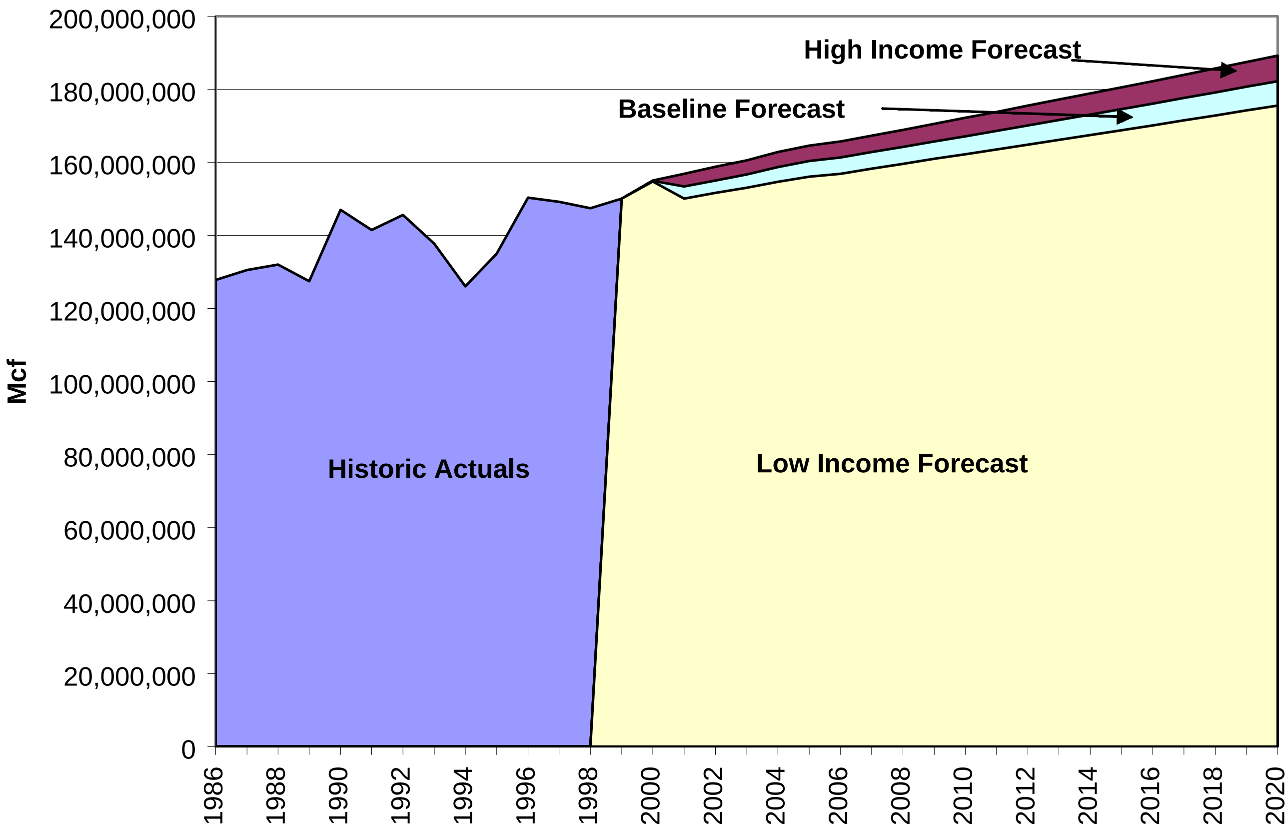

Figure 5.2: Forecast In-State Natural Gas Usage Under Different Income Scenarios

5.6: Conclusions

The sensitivity analysis for the baseline forecast was developed to examine a range of gas usage levels that could be realized under differing economic conditions. The main factor influencing these potential shifts in usage are the income and price elasticities of demand that have been estimated for each customer class. Overall, price impacts tend to have greater implications for usage relative to income impacts. This is particularly true for commercial customers that can exhibit price elasticities of –0.8 in the short run and –1.8 in the long run.

Sensitivity ranges (i.e, high, low) for price and income were developed from a fixed range over longer run 10 year averages. A given symmetrical range around this historic averages were developed for comparison purposes. The approach is similar to that developed by ISER in its Alaska forecast. However, our ranges are admittedly smaller, and more conservation than some of the outer ranges considered in the ISER analyses. Our sensitivity analysis is designed to answer a “what if” question, i.e., explore changes in the dependent variable due to lower or higher levels of the independent variables. In that sense, the levels of the independent variables represent not so much a “forecasted” values, but rather certain discrete levels, which, in our view, correspond to a qualitative label of “high” and “low”.

There are a number of other sensitivities to in-state usage that can be considered. These sensitivities include examining the implications of shifts in natural gas usage of large individual users. Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. Combined, these facilities account for close to 130 Bcf per year in natural gas usage. Expansions or closure of these facilities could have significant implications for in-state usage. The role that these facilities play in determining in-state usage trends is examined in greater detail in Chapter 7.

CHAPTER 6: EXPANDED RESIDENTIAL SERVICE

6.1: Regional Analysis of Expanded Residential Service Opportunities

In terms of the residential market, we examined two potential opportunities for increased natural gas usage:

(1) Expanding coverage of natural gas service to those remote areas that currently have no existing or proposed gas service.

(2) Increasing natural gas market penetration rates in areas that already have gas service.

In order to analyze these potential opportunities we used a geographic information system (GIS) to combine demographic geo-referenced information with information on existing and proposed natural gas service areas. This approach allowed us to establish a spatial framework for residential natural gas service in Alaska, which is required for the analysis.

According the 2000 U.S. Census of Population and Housing, Alaska has a population of 580 thousand people, which make up 205 thousand households. Approximately two thirds of the population reside in the Southcentral region. The Interior and the Southeast region account for 11 percent each, while the Far North region has only 4 percent. Anchorage, located in the Southcentral region, is the only large city in the state, it alone accounts for 45 percent of the total Alaskan population. Together, the cities of Juneau and Fairbanks, with populations of about 30,000 each, account for 10 percent of statewide population.

Figure 6.1 shows the geographic distribution of settlements within Alaska according to size. The distribution of population in the state is very uneven, with majority of the population concentrated in three major urban clusters: Anchorage; Juneau; and Fairbanks. The size of the dots in Figure 6.1 represents the size of the settlements throughout the state. Very small dots, for instance, represent settlements with less than 500 households (conventionally, population is measured in number of people; however, we are using number of households because a household represents a gas service customer). As can be seen on the map, Alaska has three major areas with population greater than 4,500 households: Juneau in the Southeast, Anchorage in the Southcentral area, and Fairbanks in Interior Alaska. There are a considerable number of settlements in Alaska with fewer than 500 households.

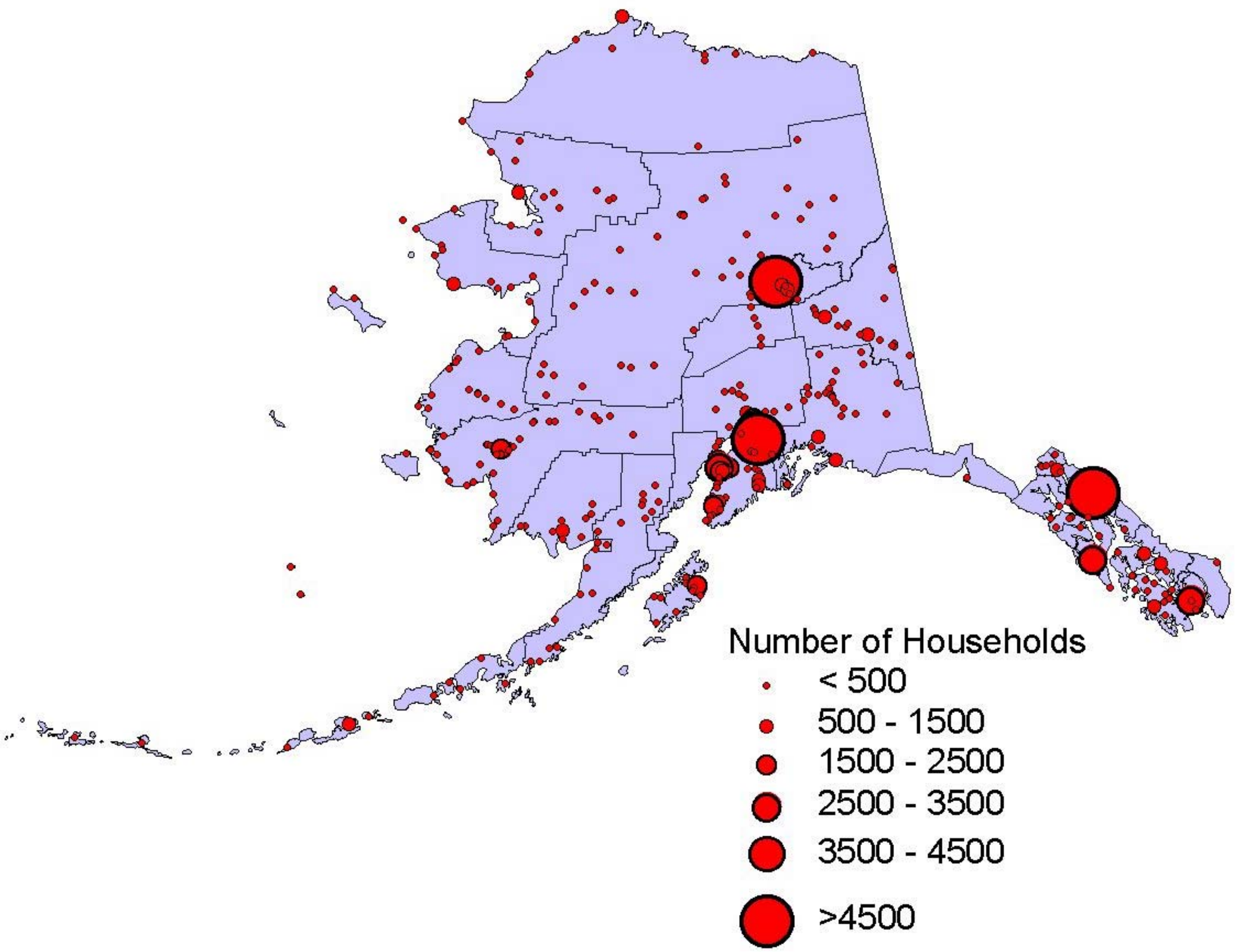

Figure 6.1 Geographical Distribution of Settlements in Alaska

Our next step after identifying settlement distributions and locations throughout the state was to identify those settlements that are currently being served by natural gas distribution systems. In addition to identifying current systems, we also identified those areas that have plans for future services. This information was collected from the Regulatory Commission of Alaska (RCA). The settlements with existing or proposed natural gas services are provided in Table 6.1. The geographic distribution of these settlements and their gas service status is presented in Figure 6.2.

Table 6.1 Settlements with Existing or Proposed Natural Gas Service

Community	Region	NG Provider	Population	Households
Angoon	Southeast	AIGC	572	184
Cordova	Southcentral	AIGC	2,454	958
Craig	Southeast	AIGC	1,397	523
Haines	Southeast	AIGC	1,811	752
Juneau	Southeast	AIGC	30,711	11,543
Kake	Southeast	AIGC	710	246
Ketchikan	Southeast	AIGC	7,922	3,197
Klawock	Southeast	AIGC	854	313
Klukwan	Southeast	AIGC	139	44
Kodiak	Southwest	AIGC	6,334	1,996
Metlakatla	Southeast	AIGC	1,375	469
Petersburg	Southeast	AIGC	3,224	1,240
Sitka	Southeast	AIGC	8,835	3,278
Skagway	Southeast	AIGC	862	401
Valdez	Southcentral	AIGC	4,036	1,494
Wrangell	Southeast	AIGC	2,308	907
Yakutat	Southeast	AIGC	680	261
Barrow	Far North	BUECI	4,581	1,371
Anchorage	Southcentral	ENSTAR	260,283	94,822
Big Lake	Southcentral	ENSTAR	2,635	971
Houston	Southcentral	ENSTAR	1,202	445
Kenai	Southcentral	ENSTAR	6,942	2,622
Nikiski	Southcentral	ENSTAR	4,327	1,514
Palmer	Southcentral	ENSTAR	4,533	1,472
Soldotna	Southcentral	ENSTAR	3,759	1,465
Sterling	Southcentral	ENSTAR	4,705	1,676
Wasilla	Southcentral	ENSTAR	5,469	1,979
Whittier	Southcentral	ENSTAR	182	86
Fairbanks	Interior	FNG	30,224	11,075
Prudhoe Bay	Far North	NORGASCO	5	1

Source: Regulatory Commission of Alaska and 2000 U.S. Census of Population and Housing.
AIGC = Alaska Interstate Gas Company.
BUECI = Barrow Utilities & Electric Cooperative, Incorporated.
FNG = Fairbanks Natural Gas, LLC.
Note: Not all the settlements receive residential gas service. AIGC is planning to provide gas service.

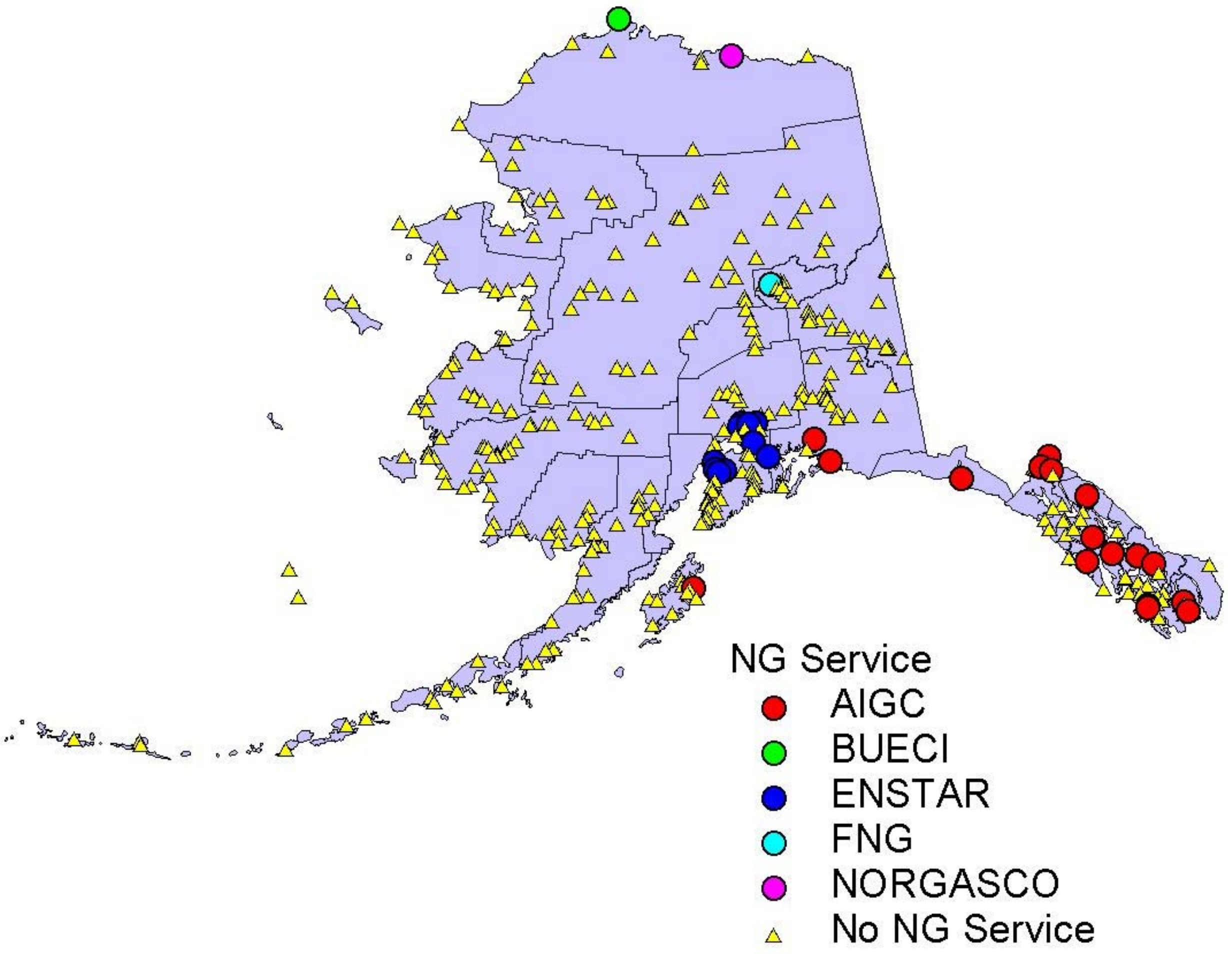

Figure 6.2: Geographical Distribution of Natural Gas Service in Alaska

Figure 6.2 shows that there are a large number of settlements that are currently not listed as having gas service. Areas covered by existing or proposed systems are restricted to Southcentral and Southeastern Alaska. Based upon publicly available information, there are other small pockets in northern Alaska and one in Interior Alaska.

Table 6.2 shows the distribution of Alaska population and households. The top portion of the table presents the numbers for each of the series, while the bottom half of the table shows the relative distribution. An important statistic reported in this table is that 30 percent of Alaska's population and 28 percent of its households are not being served by natural gas.

Table 6.2 Distribution of Alaska Population and Households by Existing or Proposed Natural Gas Service

NG Utility	Population	Households
No NG service	176,272	57,262
AIGC	74,224	27,806
BUECI	4,581	1,371
ENSTAR	294,037	107,052
FNG	30,224	11,075
NORGASCO	5	1
AK Total	579,343	204,567

NG Utility	Population	Households
No NG service	30.4%	28.0%
AIGC	12.8%	13.6%
BUECI	0.8%	0.7%
ENSTAR	50.8%	52.3%
FNG	5.2%	5.4%
NORGASCO	0.0%	0.0%

Alternatively, some 72 percent of Alaska's households currently reside in places with natural gas service. As seen in Table 6.3, 52 percent of all households in Alaska live within the Enstar's service zone. Enstar, the state's largest local distribution company (LDC), provides natural gas to residential and commercial customers in Anchorage, Big Lake, Chugiak, Eagle River, Eklutna, Girdwood, Houston, Kenai, Knik, Nikiski, Palmer, Peters Creek, Soldotna, Sterling, Wasilla, and Whittier. Enstar contemplates expanding gas distribution service to Ninilchik, Anchor Point, Homer and other lower Kenai Peninsula communities.

Table 6.3: Proposed Kenai Kachemak Pipeline Project

Community	Region	NG Planned Provider	Population	Households
Anchor Pt	Southcentral	ENSTAR	1,845	711
Clam Gulch	Southcentral	ENSTAR	173	67
Homer	Southcentral	ENSTAR	3,946	1,599
Kasilof	Southcentral	ENSTAR	471	180
Ninilchik	Southcentral	ENSTAR	772	320

Unocal Alaska and Marathon Oil Company have formed the Kenai Kachmak Pipeline, LLC and recently announced an open season for a 58-mile gas transmission pipeline between Kenai and Anchor Point near the southern end of the Kenai Peninsula. The KKPL initially would transport gas from new fields currently under exploration in the southern Kenai Peninsula into the existing pipeline distribution system operated by Enstar and Kenai-Nikiski Pipeline. Enstar eventually may construct a distribution segment between Anchor Point and Homer. The KKPL is expected to begin operation in 2004. Pipeline capacity is still unknown and will depend on exploration success. When all phases are completed, gas service could become available to the communities of Ninilchik, Anchor Point, Clam Gulch, Kasilof, and Homer. Collectively these southern Kenai Peninsula communities contain approximately 2,900 occupied households, representing about a three-percent addition to the existing 105,000 Enstar customer base. This would imply about 500 to 600 million cubic feet per year of potential residential gas service, not including commercial and electric power generation potential.

Alaska Interstate Gas Company (AICG) has proposed to develop a gas service, which would serve places containing 14 percent of all Alaska households, primarily in Southeast. According to the RCA 2000 Annual Report, AIGC was scheduled to begin serving Juneau, Ketchikan, and Sitka on July 1, 2001; Cordova, Craig, Klawock, Kodiak, Petersburg, Valdez, and Wrangell by July 1, 2005; and Angoon, Haines, Kake, Klukwan, Metlakatla, Skagway, and Yakutat by July 1, 2010. However it is important to point out that, except for Valdez, these relatively small and remote communities are located apart from the road- or rail-connected energy belt and apart from known natural gas reserves or gas transmission lines.

Table 6.4 examines the distribution of settlement size and number of households with and without natural gas service. According to the information available to our study, there are some 297 settlements with fewer than 500 households that do not have access to natural gas service. The total number of households that live in these small, non-gas service areas is approximately 25,000. There are 26 settlements in Alaska that range between 500 and 2,400 households that do not have access to natural gas service. These places account for approximately 29,000 households. There is one settlement in Alaska that has a total of 4,100 households that is currently listed as not having access to natural gas service. This is an area around the campus of University of Alaska at Fairbanks, a census designated place (CDP), College, located just outside the corporate limits of Fairbanks.

Table 6.4: Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households		
Settlement Size (000 households)	With NG Service	Without NG Service	All	With NG Service	Without NG Service	All
<0.5	10	287	297	2,450	24,599	27,049
0.5-1.4	10	19	29	11,153	15,199	26,352
1.5-2.4	4	7	11	7,165	13,360	20,525
2.5-3.4	3	0	3	9,097	0	9,097
3.5-4.4	0	1	1	0	4,104	4,104
> 4.5	3	0	3	117,440	0	117,440
All	30	314	344	147,305	57,262	204,567

Table 6.5. Cumulative Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households			Percent w/o Gas Service	
Settlement Size (000 households)	With NG	Without NG	All	With NG	Without NG	All	Settlements	Households
<0.5	10	287	297	2,450	24,599	27,049	96.6%	90.9%
<1.5	20	306	326	13,603	39,798	53,401	93.9%	74.5%
<2.5	24	313	337	20,768	53,158	73,926	92.9%	71.9%
<3.5	27	313	340	29,865	53,158	83,023	92.1%	64.0%
<4.5	27	314	341	29,865	57,262	87,127	92.1%	65.7%
All	30	314	344	147,305	57,262	204,567	91.3%	28.0%

The next step in our analysis was to estimate the amount of natural gas that could be used if the identified unserved areas of Alaska were offered access to natural gas service. This estimate has been provided in Table 6.6. Our analysis of new potential residential in-state demand has been conducted in a “boundary” fashion. That is, we have identified the outer range of new residential growth possibilities. The outer range is estimated assuming that every household will use natural gas at current average consumption rate. The first two lines in Table 6.6 identify existing residential consumption and customers. Line 3 through line 5 estimate those households that currently have access to natural gas service, or have plans for service in the near future.

Line 6 and line 7, however, estimate those households that either do not have access to natural gas service or do not utilize their ability to access natural gas service. Line 7 divided by line 2, therefore, would give the current percent of customers not taking natural gas service (not shown). Lines 8 through 11 estimate natural gas usage (based on the observed average consumption per customer) for the various types of residential households: those with natural gas service; those with proposed natural gas service; and potential usage for those that currently do not have residential natural gas service.

Line 10 shows the potential residential gas usage levels in areas without access to natural gas if service were extended to these areas. The largest concentration of these volumes, seen as a percentage in the far right hand columns, is in the Southcentral region of Alaska. Nearly 50 percent of expanded service usage volumes could come from this region. The next two largest opportunities for regional development appear to be in the Southwest region (21 percent) and the Interior region (19 percent).

We also conducted a number of additional analyses that estimated potential residential usage if the penetration rates of existing, proposed, and potential regions were expanded to 100 percent. This estimate would reflect the maximum coverage of gas usage in Alaska if all households were served. These estimates have been provided on line 12 through line 16. Line 14, for instance, estimates total gas usage if existing and proposed regions expanded their penetration rates to 100 percent.

Table 6.6: Summary Analysis of Potential Residential In-State Natural Gas Usage

			Levels						Percents of Total					
Line No.	Calculation by Line No.		Far North	Interior	Southl Central	South East	South West	Total	Far North	Interior	South Central	South East	South West	Total
1	EIA	1999 Residential NG Consumption (Mcf)	215,126	0	17,418,738	0	0	17,633,864	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
2	EIA	1999 Number of Residential Customers	1,109	0	87,815	0	0	88,924	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
3	RCA, Census	Number of Households with Existing (as of 12/31/1999) Access to NG	1,371	11,075	107,052	0	0	119,498	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
4	RCA, Census	Number of Households with Proposed Access to NG (AIGS service area) [a]	0	0	2,452	23,358	1,996	27,806	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
5	3 + 4	Number of Households with Existing or Proposed Access to NG	1,371	11,075	109,504	23,358	1,996	147,304	0.9%	7.5%	74.3%	15.9%	1.4%	100.0%
6	RCA, Census	Number of Households without Existing or Proposed Access to NG	4,550	11,456	27,101	1,794	12,361	57,262	7.9%	20.0%	47.3%	3.1%	21.6%	100.0%
7	5 - 2	Number of Households not Using Existing Access to NG	262	11,075	19,237	0	0	30,574	0.9%	36.2%	62.9%	0.0%	0.0%	100.0%
8	4 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas with Proposed Access to NG (MCF)	0	0	398,972	3,446,776	294,536	4,140,284	0.0%	0.0%	9.6%	83.2%	7.1%	100.0%
9	1 + 8	Expected Residential NG Consumption in Areas with Existing or Proposed Access to NG (Mcf)	215,126	0	17,817,710	3,446,776	294,536	21,774,148	1.0%	0.0%	81.8%	15.8%	1.4%	100.0%
10	6 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas without Existing or Proposed Access to NG (Mcf)	713,948	1,690,482	4,409,681	264,728	1,824,026	8,902,866	8.0%	19.0%	49.5%	3.0%	20.5%	100.0%
11	9 + 10	Expected Residential NG Consumption in Alaska Assuming Universal Access to NG (Mcf)	929,074	1,690,482	22,227,391	3,711,504	2,118,562	30,677,013	3.0%	5.5%	72.5%	12.1%	6.9%	100.0%
12	3 x [1 / 2]	Potential Residential NG Consumption in Areas with Existing Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,234,536	0	0	23,696,657	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
13	4 x [1 / 2]	Potential Residential NG Consumption in Areas with Proposed Access to NG Assuming 100% Market Saturation (Mcf)	0	0	486,372	4,631,891	395,807	5,514,070	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
14	12 + 13	Potential Residential NG Consumption in Areas with Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,720,907	4,631,891	395,807	29,210,727	0.9%	7.5%	74.4%	15.9%	1.4%	100.0%
15	6 x [1 / 2]	Potential Residential NG Consumption in Areas without Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	882,618	2,271,725	5,375,679	355,750	2,451,186	11,336,958	7.8%	20.0%	47.4%	3.1%	21.6%	100.0%
16	14 + 15	Potential Residential NG Consumption in Alaska Assuming Universal Access and 100% Market Saturation (Mcf)	1,148,567	4,467,897	27,096,586	4,987,642	2,846,993	40,547,685	2.8%	11.0%	66.8%	12.3%	7.0%	100.0%

[a] Places with households include Cordova and Valdez (Southcentral); Angoon, Craig, Haines, Juneau, Kake, Ketchikan, Klawock, Klukwan, Metlakatla, Petersburg, Sitka, Wrangell and Yakutat (Southeast); and Kodiak (Southwest).

Currently, the Southcentral region dominates both the total number of households with access to natural gas service, and, as a result, total residential natural gas usage. Table 6.6, line 3 shows that this region currently accounts for close to 90 percent of all households with access to natural gas service. Line 4, however, reveals that new (proposed) service opportunities are being created in other regions. These new expansion plans are primarily in the Southeastern region (84 percent of new service proposed for this area).

Another focus of the analysis is to identify households in existing natural gas service areas that do not receive service. Overall, Alaska has an approximate residential natural gas service penetration rate of 80 percent, while the Southcentral region has a somewhat higher average residential penetration rate of 82 percent. We have identified some 11,075 households in the Interior region that are within a defined natural gas utility service area. This region includes the Fairbanks North Star Borough and is examined in greater detail at the end of this chapter.

Lines 8 through 11 of Table 6.6 estimates the natural gas usage associated with households in different Alaska regions. A large portion of the estimated natural gas usage is in the Southcentral region. In addition to identifying the existing distribution of regional natural gas usage, we have also identified new opportunities for natural gas service volumes that are presented on line 10. We have identified a potential for 8.9 Bcf if service were expanded to unserved areas of Alaska. This increased usage assumes that the currently unserved areas achieve a penetration rate comparable to the state-wide average.

As indicated above, close to 50 percent of our identified new sources of expanded residential natural gas usage are located in the Southcentral region. Approximately 40 percent of those potential expanded service usage is in the Interior (19.0 percent) and Southwest (20.5 percent) regions of the state. The remaining new expanded service usage opportunities are in the Far North (8 percent) and Southeast (3 percent) regions. Line 11 sums the existing gas usage and the new potential expansions, to estimate a new in-state residential natural gas usage level based upon 1999 average usage trends and levels.

The analysis also considers opportunities for expanding gas usage in areas that currently have natural gas service coverage through increasing the market penetration rates. Line 12 and line 13, for instance, estimate the levels of gas usage that could occur in existing and proposed service areas if service penetration rates were increased from their existing levels to 100 percent. These opportunities from service expansion have been summed on line 14. We estimate approximately 7.4 (29.2-21.8) Bcf of additional usage opportunities if service penetration levels were increased to their maximum.

Approximately 74 percent of the expanded service opportunities are located in Southcentral Alaska. Close to 16 percent of the expanded service opportunities are located in Southeast Alaska. The total service expansion opportunities are much less in the remaining areas, primarily because these areas currently have no to little service to expand upon.

Line 15 examines new residential usage opportunities in currently unserved areas from a different perspective. Here, we estimate total usage opportunities if service were expanded in these regions, and penetration rates reached 100 percent. This estimate, therefore, is higher than that presented in line 10. We estimate the possibility of 11.3 Bcf of increased residential usage in currently unserved areas if 100 percent penetration rates were achieved.

Line 14 and line 15 can be compared to examine new residential natural gas usage opportunities in existing areas (line 14) with new growth opportunities in unserved areas (line 15). Both estimates assume 100 percent penetration, so the comparison, as well as the sum (line 16), represent the boundary, or outermost opportunities for expanded residential natural gas usage. Comparing lines 14 and 15, we see that increasing market penetration rates in areas with existing or proposed service (7.5 Bcf per year) yields slightly less additional consumption than expanding service into the unserved regions (8.9 Bcf per year).

We have presented three figures to try to simply the analysis presented in Table 6.6. Figure 6.3 presents a pie chart showing the break-out of the estimated usage potentials in unserved areas, versus the estimated usage in existing LDC service territories for the state. Usage in unserved areas would represent approximately 29 percent of the total (or 8.9 Bcf per year). The remaining usage is associated with areas that already have natural gas service opportunities. This figure is based upon the estimates that assumed new areas will achieve penetration rates comparable to the statewide average.

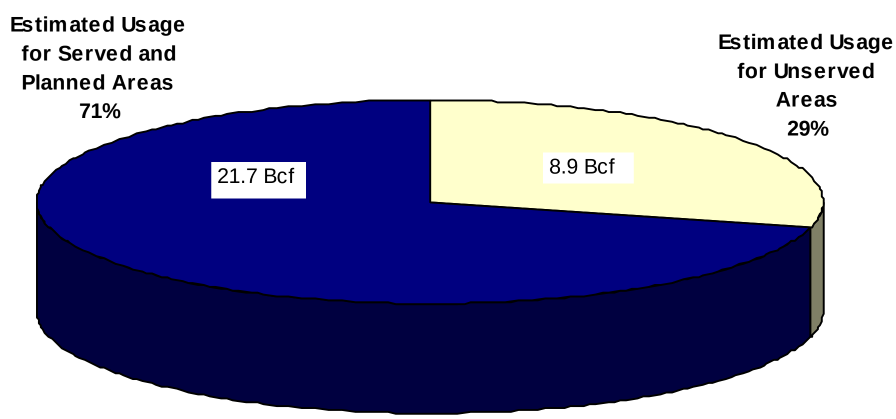

Figure 6.3: Estimated Usage in Served and Unserved Areas Assuming Statewide Average Penetration Rates

FIgure 6.4 is a similar representation, but shows total usage, and percentages, assuming 100 percent penetration of both unserved and served areas. Of the maximum total residential usage potential, usage in unserved areas represents about 28 percent of total, or 11.3 Bcf. Usage in areas currently served by LDCs increases to 29.2 Bcf, or 72 percent of total.

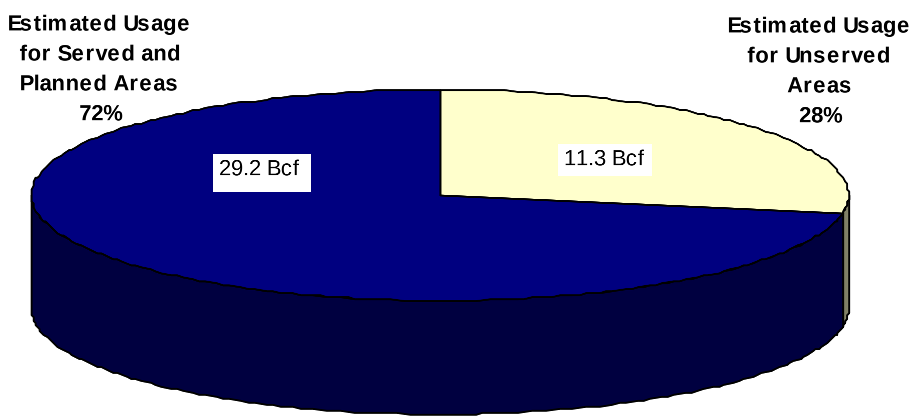

Figure 6.4: Estimated Usage in Served and Unserved Areas Assuming 100 Percent Penetration Rates

The last figure (Figure 6.5) we have presented compares the estimated usage in unserved areas with the estimated usage from expanding the statewide average penetration level from roughly 80 to 100 percent. As seen in the figure, the percentages and levels are roughly the same. Estimated usage in unserved areas could be approximately 8.9 Bcf while usage from expansion of current LDC penetration rates is 7.4 Bcf.

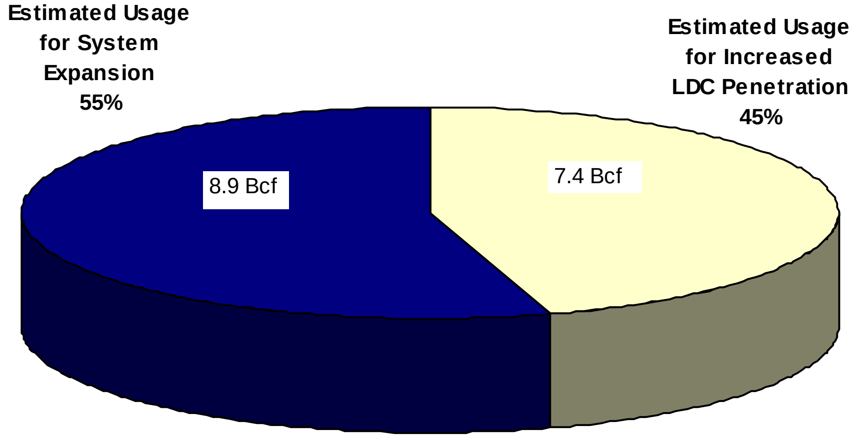

Figure 6.5: Comparison of Estimated Usage in Unserved Areas versus Increased Penetration Rates in Existing LDC Areas

The results of our detailed analysis reveal some interesting insights into new residential natural gas usage opportunities. Our analysis supports the two major conclusions:

(1) On a regional basis, Southcentral Alaska has the largest opportunities for expanding residential natural gas service beyond its current LDC service areas;

(2) On a statewide basis, potential growth in residential natural gas usage associated with increasing the penetration rates of existing local distribution systems almost equals potential growth associated with extending the service into remote areas.

6.2: Residential Proximity Analysis to Existing and Proposed Natural Gas Infrastructure

We also conducted an alternative analysis that examined the possibilities of expanding natural gas service to customers living within proximity to existing and proposed natural gas infrastructure of the state. The two sets of natural gas infrastructure that we examined included:

(1) Expansions to the existing natural gas utilities (LDCs);

(2) Service expansion opportunities in geographic proximity to the Alaska natural gas transportation pipeline.

In both cases, for any given area, physical proximity to sources of natural gas infrastructure becomes a critical factor in determining costs of the provision of natural gas. Our geographic proximity analysis proceeded along the following lines:

1. We used the geographic boundary files developed by the U.S. Census Bureau to produce a map of Alaskan settlements (cities, towns, villages, census designated places, etc.) in their administrative (or census-designated) boundaries.

2. We used the newly released STF1 file for Alaska from the 2000 U.S. Census of Population and Housing to identify the number of occupied households in each settlement.

3. We used information contained in the 2000 Annual Report of the Alaska Regulatory Commission to identify settlements with either existing or proposed natural gas service. As a result, we have classified all the settlement in Alaska as either having existing or proposed natural service (EPNGS) or as not having existing or proposed service (NOEPNG). These areas have been presented earlier in Figure 6.2.

4. For every EPNGS settlement we created four proximity zones in five-mile increments. For instance, a five-mile proximity zone is created by extending administrative borders of a settlement outward by five miles. A 10-mile zone, however, covers a territory around a settlement that is between 5 and 10 miles of its existing geographic definition. Thus, adding up the opportunities in each five-mile increment will result in the cumulative total new natural gas usage opportunities.

5. When buffers in each distance range had multiple EPNGS settlements, we merged each of these settlements into a single proximity zone. Given the concentration of many existing service areas, we created four proximity zones for Alaska. Thus, a five-mile Alaska zone covers all the territory

within five miles of the EPNGS area. These concentrations have been presented in Figure 6.6. The upper left hand side of this figure shows the state-wide concentrations. The upper right hand side is a zoomed-in view of the northern Alaska concentrations, while the lower part of the figure provides a zoomed-in view of the southern Alaska region.

6. Following the description of the proposed Alaska Highway Route (AHR) for the natural gas transportation pipeline, we developed a digital boundary for the proposed pipeline route (this region will be labeled "AHR").[1]

7. Similar to the procedure described above for EPNGS buffers, we developed four proximity zones in the increment of five miles around the AHR. These boundaries have been presented in Figure 6.7.

8. We overlaid boundaries of NOEPNGS settlements separately with EPNGS zones and with AHR zones. Thus, every NOEPNGS settlement was classified according to proximity (within 5 miles, within 10 miles, within 15 miles, within 20 miles, and beyond 20 miles) to the examined natural gas infrastructure.

9. Finally, we aggregated the number of occupied households living in NOEPNGS settlements by region and by proximity to sources of natural gas supply. Tables 6.7, 6.8, and 6.9 present the results of our analysis. We have also estimated usage associated with these household estimates and have presented them in Tables 6.10 and 6.11.

[1]For purposes of our analysis, the AHR includes spurs into the Southcentral region. These spurs, and our mapping of the AHR, is based upon the presentation provided by Alaska DNR Commissioner Pat Pourchot which is available on the Alaska Highway Natural Gas Council homepage: www.gov.state.ak.us/gascouncil

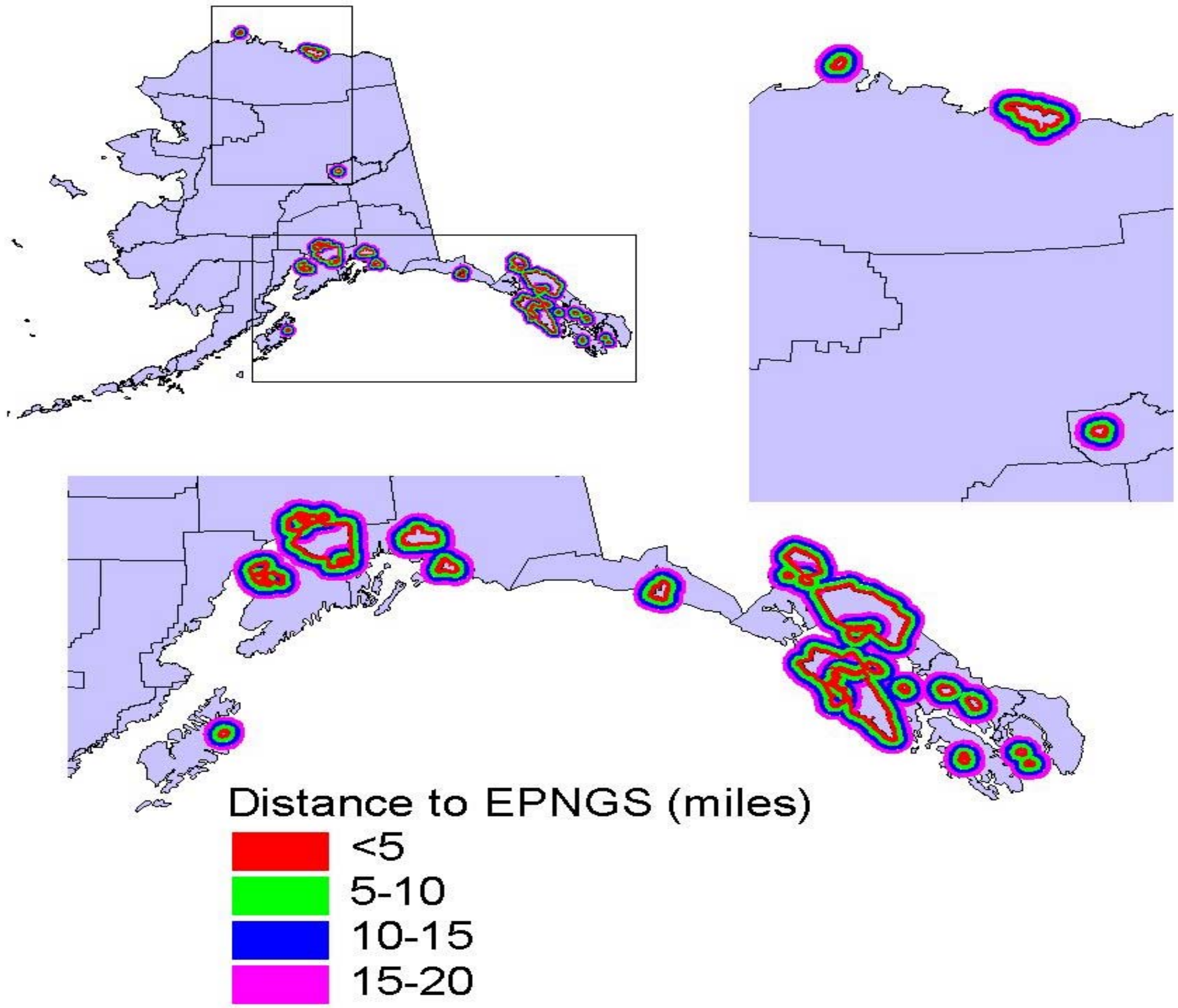

Figure 6.6: Proximity Zones around Existing and Proposed Natural Gas Systems in Alaska (EPNGS)

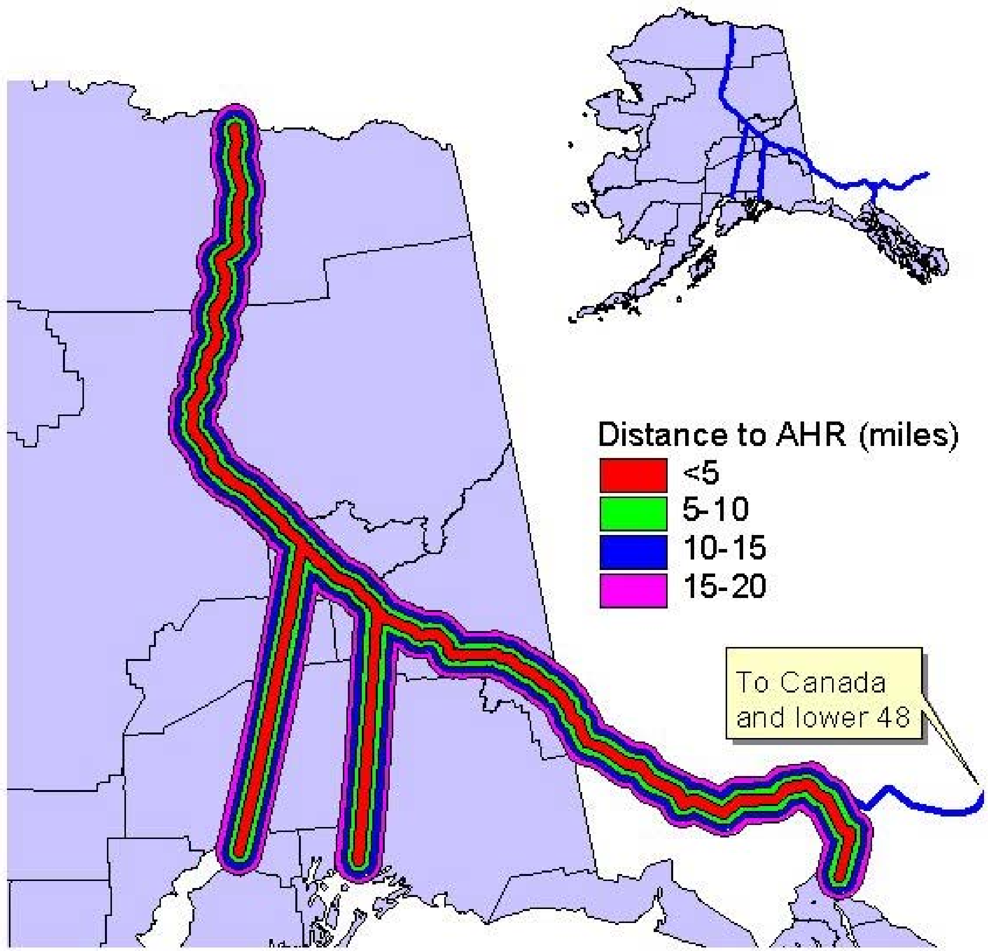

Figure 6.7: Proximity Zones Areas Around the Proposed Alaska Highway Route (AHR)

Table 6.7 reports the number of households in settlements without natural gas service (NOEPNGS), while Table 6.8 shows the frequency distribution of households within each region and for Alaska as a whole. In both tables, statistics for the proximity zones close to existing natural gas systems (EPNGS) are provided in the columns while the statistics for proximity zones close to Alaska Highway Route (AHR) are presented in the rows. These tables should be read in a cumulative and not incremental fashion.

For instance, Table 6.7 shows that in the lower most corner of the table, there are 57,262 households (intersection of "Row Total" and "Column Total") living in settlements that have no existing or proposed natural gas service. Of that amount, some 26,220 households do not live within 20 miles of either an existing natural gas distribution system (EPNGS) or the Alaska Highway Route (AHR) pipeline. These households (26,220) amount to some 45.8 percent of total non-served Alaska households. Thus, close to half of the households in Alaska reside within settlements that are not within 20 miles of neither the proposed major transportation route, nor an existing local distribution system.

On the other extreme, we have provided estimates of those households that are close to existing LDC systems and the AHR. Consider the bottom most section of Table 6.7 that has the Alaska totals. In the upper row (within 5 miles) we estimate that there are 10,325 households that are in settlements that are within both 5 miles of existing LDC systems (EPNGS) and the proposed highway route (AHR). Thus, some 18 percent of the non-served households reside in settlements that are within 5 miles of both the existing LDC systems and the AHR. The percentage can be found in the same cell on Table 6.8

We can also examine the geographic distribution of households within areas served by LDC systems and AHR separately. Consider the same section of Table 6.7 (the Alaska total section). We find that there are 11,934 households that are in settlements within 10 miles of the AHR and within 5 miles of an existing LDC system, representing 20.8 percent of the total unserved households in Alaska (Table 6.7 for cumulative percent). Moving to the right hand side of this section of bottom of Table 6.7 we find that there are 12,490 households that reside within 5 miles of the AHR and within 20 miles of an existing LDC system. This represents 21.8 percent of the unserved households (Table 6.7).

Table 6.9 presents summary of the major mileage categories and the households that fall into the proximity zones we have identified. Estimates for each region are provided in this table. In addition, to the right of the Alaska total is the sum of the households in the combined Interior and Southcentral regions.

We conclude from the geographic proximity analysis that approximately 19,000 occupied households, representing the potential for 3.8 Bcf per year of natural gas usage, are located within 20 miles of the proposed AHR and an existing gas service area. These households are located primarily in the Southcentral and Interior regions and represent about one-third of all occupied households, statewide that currently are not served by natural gas distribution systems.

Table 6.7: Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region	Distance to EPNGS Settlements → / Distance to AHR ↓	Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Far North	Within 5 miles	0	0	0	0	13	13
	Within 10 miles	0	0	0	0	13	13
	Within 15 miles	0	0	0	0	13	13
	Within 20 miles	0	0	0	0	25	25
	Beyond 20 miles	0	0	0	0	4,525	4,525
	Column Total	0	0	0	0	4,550	4,550
Interior	Within 5 miles	5,555	5,732	7,403	7,720	1,761	9,481
	Within 10 miles	5,555	5,732	7,403	7,939	1,761	9,700
	Within 15 miles	5,555	5,732	7,403	7,939	1,787	9,726
	Within 20 miles	5,555	5,732	7,403	7,939	1,822	9,761
	Beyond 20 miles	0	0	0	0	1,695	1,695
	Column Total	5,555	5,732	7,403	7,939	3,517	11,456
South Central	Within 5 miles	4,770	4,770	4,770	4,770	1,400	6,170
	Within 10 miles	6,379	6,417	6,417	6,417	1,409	7,826
	Within 15 miles	9,259	9,297	9,297	9,297	1,771	11,068
	Within 20 miles	11,162	11,219	11,219	11,219	2,150	13,369
	Beyond 20 miles	4,849	5,474	5,561	5,778	7,954	13,732
	Column Total	16,011	16,693	16,780	16,997	10,104	27,101
South East	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	19	19	19	19	0	19
	Beyond 20 miles	434	590	926	1,160	615	1,775
	Column Total	453	609	945	1,179	615	1,794
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	743	817	841	930	11,431	12,361
	Column Total	743	817	841	930	11,431	12,361
Alaska Total	Within 5 miles	10,325	10,502	12,173	12,490	3,174	15,664
	Within 10 miles	11,934	12,149	13,820	14,356	3,183	17,539
	Within 15 miles	14,814	15,029	16,700	17,236	3,571	20,807
	Within 20 miles	16,736	16,970	18,641	19,177	3,997	23,174
	Beyond 20 miles	6,026	6,881	7,328	7,868	26,220	34,088
	Column Total	22,762	23,851	25,969	27,045	30,217	57,262

Table 6.8: Relative Frequency Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	99.5%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	48.5%	50.0%	64.6%	67.4%	15.4%	82.8%
	Within 10 miles	48.5%	50.0%	64.6%	69.3%	15.4%	84.7%
	Within 15 miles	48.5%	50.0%	64.6%	69.3%	15.6%	84.9%
	Within 20 miles	48.5%	50.0%	64.6%	69.3%	15.9%	85.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	14.8%	
	Column Total	48.5%	50.0%	64.6%	69.3%		100.0%
South Central	Within 5 miles	17.6%	17.6%	17.6%	17.6%	5.2%	22.8%
	Within 10 miles	23.5%	23.7%	23.7%	23.7%	5.2%	28.9%
	Within 15 miles	34.2%	34.3%	34.3%	34.3%	6.5%	40.8%
	Within 20 miles	41.2%	41.4%	41.4%	41.4%	7.9%	49.3%
	Beyond 20 miles	17.9%	20.2%	20.5%	21.3%	29.3%	
	Column Total	59.1%	61.6%	61.9%	62.7%		100.0%
South East	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Beyond 20 miles	24.2%	32.9%	51.6%	64.7%	34.3%	
	Column Total	25.3%	33.9%	52.7%	65.7%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	6.0%	6.6%	6.8%	7.5%	92.5%	
	Column Total	6.0%	6.6%	6.8%	7.5%		100.0%
Alaska Total	Within 5 miles	18.0%	18.3%	21.3%	21.8%	5.5%	27.4%
	Within 10 miles	20.8%	21.2%	24.1%	25.1%	5.6%	30.6%
	Within 15 miles	25.9%	26.2%	29.2%	30.1%	6.2%	36.3%
	Within 20 miles	29.2%	29.6%	32.6%	33.5%	7.0%	40.5%
	Beyond 20 miles	10.5%	12.0%	12.8%	13.7%	45.8%	
	Column Total	39.8%	41.7%	45.4%	47.2%		100.0%

Table 6.9: Summary of Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	5,555	16,011	453	743	22,762	21,566
Within 5 miles of AHR	13	9,481	6,170	0	0	15,664	15,651
Within 5 miles of EPNGS and AHR	0	5,555	4,770	0	0	10,325	10,325
Within 10 miles of EPNGS	0	5,732	16,693	609	817	23,851	22,425
Within 10 miles of AHR	13	9,700	7,826	0	0	17,539	17,526
Within 10 miles of EPNGS and AHR	0	5,732	6,417	0	0	12,149	12,419
Within 15 miles of EPNGS	0	7,403	16,780	945	841	25,969	24,183
Within 15 miles of AHR	13	9,726	11,068	0	0	20,807	20,794
Within 15 miles of EPNGS and AHR	0	7,403	9,297	0	0	16,700	16,700
Within 20 miles of EPNGS	0	7,939	16,997	1,179	930	27,045	24,936
Within 20 miles of AHR	25	9,761	13,369	19	0	23,174	23,130
Within 20 miles of EPNGS and AHR	0	7,939	11,219	19	0	19,177	19,518
Beyond 20 miles of both EPNGS and AHR	4,525	1,695	7,954	615	11,431	26,220	9,649

Table 6.10: Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Region	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	2,578	2,578
Far North	Within 10 miles	0	0	0	0	2,578	2,578
Far North	Within 15 miles	0	0	0	0	2,578	2,578
Far North	Within 20 miles	0	0	0	0	4,958	4,958
Far North	Beyond 20 miles	0	0	0	0	897,308	897,308
Far North	Column Total	0	0	0	0	902,265	902,265
Interior	Within 5 miles	1,101,557	1,136,656	1,468,015	1,530,876	349,206	1,880,082
Interior	Within 10 miles	1,101,557	1,136,656	1,468,015	1,574,304	349,206	1,923,510
Interior	Within 15 miles	1,101,557	1,136,656	1,468,015	1,574,304	354,362	1,928,666
Interior	Within 20 miles	1,101,557	1,136,656	1,468,015	1,574,304	361,303	1,935,606
Interior	Beyond 20 miles	0	0	0	0	336,119	336,119
Interior	Column Total	1,101,557	1,136,656	1,468,015	1,574,304	697,421	2,271,725
South Central	Within 5 miles	945,891	945,891	945,891	945,891	277,620	1,223,511
South Central	Within 10 miles	1,264,956	1,272,491	1,272,491	1,272,491	279,405	1,551,896
South Central	Within 15 miles	1,836,060	1,843,595	1,843,595	1,843,595	351,189	2,194,784
South Central	Within 20 miles	2,213,425	2,224,728	2,224,728	2,224,728	426,345	2,651,073
South Central	Beyond 20 miles	961,557	1,085,494	1,102,746	1,145,777	1,577,278	2,723,056
South Central	Column Total	3,174,981	3,310,222	3,327,474	3,370,505	2,003,623	5,374,128
South East	Within 5 miles	0	0	0	0	0	0
South East	Within 10 miles	0	0	0	0	0	0
South East	Within 15 miles	0	0	0	0	0	0
South East	Within 20 miles	3,768	3,768	3,768	3,768	0	3,768
South East	Beyond 20 miles	86,062	116,997	183,626	230,028	121,955	351,983
South East	Column Total	89,830	120,765	187,394	233,796	121,955	355,750
South West	Within 5 miles	0	0	0	0	0	0
South West	Within 10 miles	0	0	0	0	0	0
South West	Within 15 miles	0	0	0	0	0	0
South West	Within 20 miles	0	0	0	0	0	0
South West	Beyond 20 miles	147,337	162,011	166,770	184,419	2,266,767	2,451,186
South West	Column Total	147,337	162,011	166,770	184,419	2,266,767	2,451,186
Alaska Total	Within 5 miles	2,047,448	2,082,547	2,413,906	2,476,767	629,404	3,106,171
Alaska Total	Within 10 miles	2,366,512	2,409,147	2,740,506	2,846,795	631,189	3,477,984
Alaska Total	Within 15 miles	2,937,616	2,980,251	3,311,610	3,417,899	708,129	4,126,028
Alaska Total	Within 20 miles	3,318,749	3,365,151	3,696,510	3,802,799	792,605	4,595,404
Alaska Total	Beyond 20 miles	1,194,956	1,364,502	1,453,142	1,560,224	5,199,426	6,759,650
Alaska Total	Column Total	4,513,705	4,729,653	5,149,653	5,363,024	5,992,031	11,355,055

Table 6.11: Summary of Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	1,101,557	3,174,981	89,830	147,337	4,513,705	4,276,538
Within 5 miles of AHR	2,578	1,880,082	1,223,511	0	0	3,106,171	3,103,593
Within 10 miles of EPNGS	0	1,136,656	3,310,222	120,765	162,011	4,729,653	4,446,878
Within 10 miles of AHR	2,578	1,923,510	1,551,896	0	0	3,477,984	3,475,406
Within 15 miles of EPNGS	0	1,468,015	3,327,474	187,394	166,770	5,149,653	4,795,489
Within 15 miles of AHR	2,578	1,928,666	2,194,784	0	0	4,126,028	4,123,450
Within 20 miles of EPNGS	0	1,574,304	3,370,505	233,796	184,419	5,363,024	4,944,809
Within 20 miles of AHR	4,958	1,935,606	2,651,073	3,768	0	4,595,404	4,586,679
Beyond 20 miles of both EPNGS and AHR	897,308	336,119	1,577,278	121,955	2,266,767	5,199,426	1,913,397

6.3: Gas Opportunities in the Interior Region

One of the nearest concentrations of potential gas usage in Alaska is in the Interior section of the state. Table 6.7 shows that of the 15,664 unserved households in the state, some 5,555 (35 percent) are in the Interior region. Over 50 percent of all the unserved households in the state that are within 10 miles of the proposed AHR project are in the Interior region of the state. Some 41 percent of all households in the state living within 20 miles of both types of infrastructure (distribution and proposed transmission) are in the Interior region.[2] We explore the degree of residential geographic concentration, and its implications for potential gas demand in this section.

6.3.1: Overview of the Greater Fairbanks Region: The Fairbanks North Star Borough (FNSB) encompasses nearly 7,500 square miles of interior Alaska near the confluence of the Tanana and Chena Rivers and is located in the proximity of the Alaska Highway route for the proposed gas pipeline. As seen in Table 6.12**,** Borough population was 82,840 in 2001. Some 53,300 people reside in the ten communities and two military bases in the NSB region. The remaining 29,500 FNSB inhabitants reside in unincorporated places in the greater Fairbanks North Star Borough area. The City of Fairbanks, with a population of 30,224 is Alaska's second largest community and the Borough hub. College, a separate community located three miles northwest of Fairbanks, is the location of the University of Alaska at Fairbanks and includes an additional 11,400 residents.

The greater FNSB area has been inhabited by Koyukon Athabascans for thousands of years. During the gold rush era of the 1890s, Fairbanks began a steamboat landing. The University of Alaska Fairbanks was established in 1915. Eielson Air Force Base, established during Worth War II, is 26 miles south of Fairbanks, near the City of North Pole (1,570 population) and accounts for an additional 5,400 Borough residents. The area continued to grow with construction of the Alcan Highway and with the Trans-Alaska oil pipeline.

The FNSB contains 29,800 occupied housing units plus an additional 3,500 vacant or seasonal dwellings. Approximately one third of these are located in unincorporated places. Average occupied household size in the borough is 2.68, down from 2.70 in 1990.

Average temperatures in the greater FNSB range from –22 degrees Fahrenheit during winter to 72 degrees Fahrenheit during summer. Seasonal extremes can far exceed these this temperate range. According to the Stone and Webster *Railbelt Intertie Reconnaissance Study* (1989, Intertie Study), heating degree days in the Fairbanks area are approximately 40 percent greater than

[2]There are 7,939 unserved households in the Interior region compared to a state-wide total 19,777. See Table 6.1 for details.

Anchorage. The average occupied household would consume approximately 235 Mcf of natural gas per year.[3]

[3]Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study,* 1989.

Table 6.12: Fairbanks North Star Borough Population and Housing Characteristics, 2000-2001

		Population			Housing Units				Average Household Size[2]
					Occupied	Vacant		Total	
Item		In Occ HHs	In Group Qs	Total		Total	Seasonal		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	College	10,651	751	11,402	4,104	397	54	4,501	2.60
2	Ester	1,600	80	1,680	727	87	22	814	2.20
3	Fairbanks[1]	28,325	1,899	30,224	11,075	1,282	121	12,357	2.56
4	Fox	300	-	300	119	40	2	159	2.52
5	Harding Lake	216	-	216	98	391	371	489	2.20
6	Moose Creek	541	1	542	223	57	-	280	2.43
7	North Pole	1,561	9	1,570	605	48	1	653	2.58
8	Pleasant Valley	623	-	623	219	27	13	246	2.84
9	Salcha	854	-	854	317	71	36	388	2.69
10	Two Rivers	482	-	482	177	15	7	192	2.72
11	Subtotal	45,153	2,740	47,893	17,664	2,415	627	20,079	2.56
12	Eileson AFB	5,090	310	5,400	1,448	83	-	1,531	3.52
13	Subtotal	50,243	3,050	53,293	19,112	2,498	627	21,610	2.63
14	Unincorporated	29,517	30	29,547	10,665	1,016	366	11,681	2.77
15	Fairbanks NSB	79,760	3,080	82,840	29,777	3,514	993	33,291	2.68
16	Fairbanks NSB (1990)	74,139	3,581	77,720	26,693	5,130	-na-	31,823	2.70

[1] Includes Fort Wainwright.

[2] Equal to ratio of population in occupied households (a) to occupied housing units (d).

6.3.2: Residential Sector Gas Usage: Residential space heating is accomplished primarily with fuel oil. Electricity, and to a lesser extent, coal and wood, provide only modest baseload space heating requirements.[4] The high incidence of population in unincorporated places, and general lack of population density in the FNSB, is a barrier to widespread gas utility service throughout the area. The authors and expert reviewers of the 1989 Intertie Study determined that a subset equal to 38 percent of the Borough, representing the areas of Fairbanks, North Pole, Farmers Loop, and Beaver Loop comprise the "gas service area" that may be economically served by a gas utility.[5] The number of households in the Fairbanks North Star borough gas service area in 2001 is estimated to be approximately 11,300.

Fairbanks Natural Gas, LLC has operated as a local distribution company for residential and commercial natural gas service in the city of Fairbanks since 1998. Gas from the Enstar system is liquefied in a small facility near Wasilla and transported by cryogenic tanker trailers to its local distribution pipeline system in Fairbanks. As shown in Table 6.13, the residential and commercial natural gas customer base has expanded from 50 in 1999 to 300 in 2001. Average gas usage per customer is about 560 Mcf per year. Retail prices varied from $6.29 to $7.59 per Mcf, depending on customer class and volume of gas usage. The average retail price of gas was $7.19 over the three-year period, 1999-2001.

Table 6.13: Fairbanks Natural Gas, LLC Customers and Gas Usage, 1998-2002

	Customers				**Gas Usage**			
	Residential	Commercial		Total	Total	Average	Receipts	Price
Year		Large	Small		Mcf/Year	Mcf/Year	$/Year	$/ Mcf
1998				18	3,511	195.1	$ 24,555	$ 6.99
1999				50	29,684	593.7	203,906	6.87
2000				130	73,418	564.8	497,304	6.77
2001	152	10	205	367	157,776	429.9	1,179,208	7.47
2002[a]					275,000		2,400,000	8.73
					Average (1999-2001)	**529.4**		**$ 7.21**

The 1989 Intertie Study projected households to grow on average 2 percent annually from the year 2000 to 2010. The statewide annual average household growth used for base case projections by the Institute of Social and Economic Research (2001)[6] is 1.19 percent during the period 2000-2009. The upper range of growth assumes a set of optimistic conditions such as an increase in the real price of ANS Crude, development of ANWR, and the construction of the gas

[4]U.S. Department of Energy, Energy Information Administration. *Residential Energy Consumption Survey*.

[5]Ibid, Vol. 10.

[6]Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025,* October ,2001.

pipeline, among other large projects. While the success of the other events is not assured, the construction of the gas pipeline is a necessary condition for the delivery of ANS gas to Fairbanks. Given its location on the pipeline route, Fairbanks is assumed to grow at the forecasted statewide rate of 1.5 percent through 2009. At this rate, occupied households in the gas service area would grow to 12,558 in 2009 (Table 6.14).

The 1989 Intertie Study used historical residential gas usage in Anchorage, adjusted for 40 percent more heating degree-days, to forecast average annual residential gas utility usage in Fairbanks. This forecast was based on the demand for each existing fuel source and an assumed gas market penetration factor. In turn, this penetration rate is driven largely by the difference between the price of natural gas and its substitutes. As shown in Table 6.14**,** the penetration rate used for the Fairbanks gas service area residential sector varies from 25 percent to 83 percent. The high penetration rate is based on the assumption that the price of gas will be half that of fuel oil, per million BTUs. This rate is lower than Enstar's experience in the Southcentral region, which is ranges from 90 percent, 95 percent, and 98 percent for electricity, fuel oil and propane substitutes, respectively.

Table 6.14: Summary of Potential Natural Gas Usage in the Fairbanks North Star Borough Area by Sector in 2009

Line No.		Formula		Low	Medium	High
1	**Residential Sector**					
2	Projected Total Occupied HHs in 2009[1]		33,048			
3	Proportion of HHs in Gas Service Area[2]		38.0%			
4	Number of HHs in Gas Service Area		12,558			
5	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
6	Number of HHs Obtaining Gas Service	Line 4 x Line 5		3,140	6,279	10,423
7	Average Annual Household Gas Usage (Mcf/Yr)[2]		235			
8	**Potential Residential Gas Usage in 2009 (Bcf/Yr)**	(Line 6 x Line 7)/1,000,000		**0.7**	**1.5**	**2.4**
9	**Commercial Sector**					
10	FNSB Commercial Space in 1997 (Million Sq Ft)[3]		18.5			
11	Non-Residential Commercial Space to be Heated (Million Sq Ft)[3]		13.3			
12	Projected Non-Res Commercial Space in 2009 (Million Sq Ft)		15.9			
13	Average Commercial Gas Usage (Mcf per Square Foot)[2]		206			
14	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
15	**Potential Commercial Gas Usage in 2009 (Bcf/Yr)**	(Line 12 x Line 13 x Line 14)/ 1,000		**0.8**	**1.6**	**2.7**
24	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 8 and 15)		**1.6**	**3.1**	**5.2**

Table Notes:

1 Annual average growth is assumed to equal to 1.5% based on the analysis in Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025*, October 2001.

2 83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study,* 1989.

3 Special tabulation by Carl McManus, Deputy Appraiser for FNSB (1997).

It is important to remember that a key factor in energy mode switch is recovery of upfront investment cost of heating system conversion to the alternate fuel. The rule-of-thumb for gas utilities' market planning is that if a customer can recoup their cost of conversion within three years then the penetration rate will be over 95 percent, at increments of 30 percent to 35 percent each year over a three to five year period.[7] Although wood heat is not exactly homogenous with thermostat-controlled central heating furnaces, they serve the same ultimate purpose. The 1989 Intertie Study concluded that only 10 percent of all the residences currently burning wood in the greater Fairbanks gas service area would switch to natural gas.

As shown in Table 6.14, potential residential gas usage for space heating and projected in 2009 in the greater Fairbanks area varies from between 0.7 to 2.4 Bcf per year, depending on the rate of gas service penetration. By comparison current gas usage for space heating in the Enstar system in Southcentral is approximately 36 Bcf.[8]

6.3.3: Commercial Sector Gas Usage: The potential for gas consumption by commercial users in the FNSB, such as office buildings and hospitals is summarized in Table 6.14. Commercial energy consumption of gas is assumed to depend on the amount of commercial square footage in use. In 1997, Fairbanks North Star Borough has 18.5 million commercial square feet on their tax roles.[9] Of that total, 13.3 million square feet represent nonresidential space to be heated. The 1989 Intertie Study assumed that commercial building square footage would increase in step with increases in population. This rate will cause commercial, heated square footage to grow to approximately 15.9 million square feet by 2009 and require between 0.8 and 2.7 Bcf per year, depending on the rate of gas service penetration (Table 6.14).

[7]Communication between ADNR and Dan Dieckgraeff of Enstar, July 1997.

[8]This figure is for residential and commercial usage only. DOE reported total retail sales by Enstar for 1999 is 45.6 Bcf (includes some direct served utility and industrial usage). Gas usage for the region, including the Agrium plant, LNG production, other utility generation, and lease use of natural gas is 213 Bcf.

[9]Special tabulation provided to ADNR by Carl McManus, Deputy Appraiser for FNSB, (1997).

CHAPTER 7: NEW AND EXISTING INDUSTRIAL USAGE OPPORTUNITIES

This chapter investigates the natural gas requirements for new and existing industries in Alaska's economy. The two new industries that we examined included the addition of a major Internet server facility as well as a major petrochemical facility. We also consider the possibilities for expanded natural gas use in the LNG plant operated by Phillips and Marathon and the ammonia-urea plant, recently acquired from Unocal by Agrium, Inc., both located near Kenai, Alaska.

7.1: New Natural Gas Usage Opportunities: Internet Server Facility

Data centers, also referred to as "server farms" or "dot-com hotels" are buildings that house computer equipment to support information and communication systems.[1] It is commonly recognized that these data centers have energy usage requirements that are generally higher than most residential or commercial buildings. The exact usage levels of the facilities, however, are much disputed given how new this sector is to the economy, as well as some common misunderstandings about the energy requirements of the different types and sizes of these facilities.

A recently released report prepared at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratories, has offered a number of new insights into these facilities and their energy usage levels. One of the considerable contributions of this study has been to define a set of common metrics upon which to estimate Internet server energy usage. A brief digression on these matrices is helpful in terms of understanding how we estimated the potential energy needs of a new Internet facility in Alaska. This discussion will focus on the power requirements of the new facilities. Later, these power requirements will be translated into new natural gas usage opportunities.

Power requirements in data centers are commonly referred to as the "power density" of the facility as measured in watts per square foot (W/sq.ft). What is commonly not clarified is exactly what square feet of an internet server facility is the most relevant. Data centers, for instance, can vary considerable in both size and composition.

[1] This chapter of our report borrows heavily from recently completed research conducted at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratory. This recent research provides an excellent analysis of Internet server farm energy requirements and debunks many recent estimates showing considerable energy demand growth from Internet facilities. This chapter of our report will refrain from repeated citations, however, the reader is encouraged to review the following report for analysis and energy usage estimates that we have used to estimate new Internet natural gas usage opportunities: Jennifer D. Mitchell-Jackson. *Energy Needs in an Internet Economy: A Closer Look at Data Centers*. M.S. Thesis. University of California, Berkeley, 2001.

A data center, like many commercial establishments, can be characterized by its gross floor space. Multiplying this gross floor space by a given power density factor can lead overestimates of power requirements for these facilities. In order to get an accurate representation of these uses, data center building compositions need to be disaggregated into its component parts. Understanding the uses and decomposition of an Internet server facility highlights the need for two important distinctions:

> ***Computer power density:*** the power drawn by the computer equipment divided by the central computer room floor area; and
>
> ***Building power density:*** the total facility power requirements divided by the building gross square feet.

The recent LBL study found that close examination of these characteristics are important since energy usage at these facilities is often overstated due to the usable size of a given facility and the utilization of the equipment within a given relevant space. The LBL study, using actual data from Internet facilities and building information found that actual power density for a typical facility was much less than commonly accepted estimates. For the facility under investigation in the LBL study, researchers found that actual power requirements were 1.4 MWs compared to the "misinformed forecast" of 7.5 MW.[2]

Our analysis uses the LBL ranges of computer floor power densities to estimate ranges of potential power and gas requirements for a typical facility. In addition to three potential power density factors, we used a range of computer floor sizes (in square feet) to estimate the potential total energy requirements. Our analysis assumes that all new Internet power requirements will be generated with natural gas fired generators. Thus, our estimates are an outer boundary of the potential gas usage that could result from a new internet facility.

Lastly, our analysis assumes that power requirements will be generated on-site. We examine three different types of small-scale power generation technologies: a small gas turbine; a reciprocating engine; and a fuel cell. Various heat rate assumptions were used to convert power requirements to natural gas usage requirements. The summary results from our findings are presented in Table 7.1

[2]The misinformed forecast took total design power density and multiplied this by total building square feet. Thus size and utilization were overestimated.

Table 7.1: Summary of Internet Server Power and Gas Usage

		Gas Turbine		*Reciprocating Engine*		*Fuel Cell*	
Facility Size, Power Density	**Generator Capacity (kW)**	**Annual Generation (kWh)**	**Annual Gas Usage (Mcf)**	**Annual Generation (kWh)**	**Annual Gas Usage (Mcf)**	**Annual Generation (kWh)**	**Annual Gas Usage (Mcf)**
Small Facility, Low Power Density	420	3,495,240	34,952	3,495,240	45,438	3,495,240	20,971
Small Facility, Medium Power Density	720	5,991,840	59,918	5,991,840	77,894	5,991,840	35,951
Small Facility, High Power Density	1,020	8,488,440	84,884	8,488,440	110,350	8,488,440	50,931
Medium Facility, Low Power Density	1,050	8,738,100	87,381	8,738,100	113,595	8,738,100	52,429
Medium Facility, Medium Power Density	1,800	14,979,600	149,796	14,979,600	194,735	14,979,600	89,878
Medium Facility, High Power Density	2,550	21,221,100	212,211	21,221,100	275,874	21,221,100	127,327
Large Facility, Low Power Density	1,680	13,980,960	139,810	13,980,960	181,752	13,980,960	83,886
Large Facility, Medium Power Density	2,880	23,967,360	239,674	23,967,360	311,576	23,967,360	143,804
Large Facility, High Power Density	4,080	33,953,760	339,538	33,953,760	441,399	33,953,760	203,723

The Internet facility usages presented in Table 7.1 are comparable to a recently announced Internet server farm that is considering development in Alaska. Netricity, L.L.C. has proposed to develop an Internet server farm that would provide web-hosting services and be connected to clients and users by the fiber optic system that runs the length of the trans-Alaska crude pipeline.[3] According to the proposal, the $1 billion facility would house 500,000 Internet servers in a one billion square foot building, with gas usage of approximately 120 MMcf/d. The facility would generate approximately 400 MW of electricity. Assuming that all of this electricity is used on site, this level of power usage (400 watts per square foot) is considerably higher than the high power density example illustrated above (85 watts per square foot).[4]

7.2: New Natural Gas Usage Opportunities: Petrochemical Facility

The potential gas usage opportunities associated with new petrochemical industries in Alaska is the subject of this section. In part, this analysis was stimulated by the opportunities that are currently being explored by Williams Energy Company. In a presentation before the Alaska Highway Natural Gas Policy Council, Williams announced that it was initiating a study of the petrochemical opportunities within the state. One potential option that has been discussed is the development of a project producing ethylene and propylene.

The Williams proposal is based upon a facility that would use over one Bcf/d of natural gas. The plant would take ethane from the natural gas stream to crack ethylene. The ethylene, in turn, is used to develop polyethylene pellets, which would be shipped by rail to Anchorage or Seward for tanker shipment to global markets. Most of the residual gas (methane) would be re-injected back into the natural gas pipeline serving the facility. The plant would employ close to 350 full time personnel and a potential payroll of $18 million per year, with as much as $15 million a year paid to the Alaska Railroad for transportation services.[5] This petrochemical facility opportunity, according to company spokespeople, is still under investigation.

Almost all ethylene produced is consumed as feedstock for manufacturing other petrochemicals. Although some ethylene is shipped across the oceans in large quantities, the preference is usually to ship first-generation products such as polyethylene, or ethyl benzene.[6] The economics for the production of ethylene depends to a large extent on the prices for feedstocks and co-products and transportation charges. In the U.S., the feedstocks of choice have been the

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[3] *Petroleum News Alaska*, Volume 7, Number 101-1, August 1, 2001

[4] The Netricity proposal is not clear on exactly what square feet are being presented in its overall proposed project size. As noted earlier, power density is higher when concentrated on core computer room density.

[5] Kay Cashman. "Williams Wants To Operate Gasline. *Petroleum News Alaska*. (December 2, 2001): 11.

[6] *Kirk-Othmer Encyclopedia of Chemical Technology*. Fourth Edition, Volume 9. New York: John Wiley and Sons: 908.

lighter feeds of ethane and propane. Approximately 70 percent of U.S. ethylene production is from ethane, propane, and butane. Ethane feed generally gives the lowest cost of production and the lowest capital investment relative to other feedstocks.[7] Cheaper alternative feedstocks, in some instances, can offset this advantage.

In the U.S., the Gulf Coast produces and consumes the majority of the ethylene production. In fact, six of the 10 largest plants in the U.S. are in Texas and Louisiana. These plants are served by an extensive system of pipelines connecting the production and consuming plants. Currently operational U.S. ethylene plants, their locations, and typical feedstocks are provided in Table 7.2. These facilities are provided in the annual International Survey of Ethylene From Steam Crackers*, Oil and Gas Journal*, April 2001.

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[7] *Ibid.*, 910.

Table 7.2: Major Ethylene Facilities in the U.S.

Facility	Location	Total Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity Is Based				
			Ethane	Propane	Butane	Naptha	Other
BP	Chocolate Bayou, TX	1,451,000	50%	35%		15%	
Chevron Phillips Chemical Co	Cedar Bayou, TX	794,000	30%	20%	25%	25%	
Chevron Phillips Chemical Co	Port Arthur, TX	794,000	70%	30%			
Chevron Phillips Chemical Co	Sweeny, TX	181,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	318,000	100%				
Chevron Phillips Chemical Co	Sweeny, TX	680,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	907,000	38%	37%	25%		
Condea Vista Co	Westlake, LA	447,000	100%				
Dow Chemical Co	Freeport, TX	590,000	50%	50%			
Dow Chemical Co	Freeport, TX	950,000	10%	70%		20%	
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%			
Dow Chemical Co	Plaquemine, LA	680,000	20%	30%		50%	
Dow Chemical Co	Seadrift, TX	440,000	100%				
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%	
Dow Chemical Co	Taft, LA	410,000	25%	25%		50%	
Dow Chemical Co	Texas City, TX	680,000	95%	5%			
DuPont	Orange, TX	590,000	100%				
Eastman Chemical Co	Longview, TX	684,000	25%	67%	7%	1%	
Equistar Chemical Co	Channelview, TX	875,000	5%			95%	
Equistar Chemicals, LP	Chocolate Bayou, TX	875,000	5%			95%	
Equistar Chemicals, LP	Clinton, IO	544,000				100%	
Equistar Chemicals, LP	Corpus Christi, TX	476,000	80%	20%			
Equistar Chemicals, LP	Lake Charles, LA	771,000	10%	30%		60%	
Equistar Chemicals, LP	LaPorte, TX	385,000	80%	20%			
Equistar Chemicals, LP	Morris, IL	789,000	60%	20%		20%	
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%			
ExxonMobil Chemical Co	Baytown, TX	882,000					
ExxonMobil Chemical Co	Beaumont, TX	1,890,000	50%	15%	35%		
ExxonMobil Chemical Co	Houston, TX	816,000	90%	10%			
Formosa Plastics Corp	Point Comfort, TX	356,000	33%	33%		34%	
Hunstman Corp	Odessa, TX	714,000					
Hunstman Corp	Port Arthur, TX	230,000				60%	40%
Hunstman Corp	Port Neches, TX	551,000					
Javelina Co	Corpus Christi, TX	136,000					
Shell Chemicals Ltd	Deer Park, TX	151,000	15%		5%	50%	30%
Shell Chemicals Ltd	Norco, LA	952,000	45%	5%	5%	45%	
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%
Sunoco Inc	Marcus Hook, PA	225,000	50%	50%			
Westlake Petrochemicals Corp	Calvert City, KY	181,000		100%			
Westlake Petrochemicals Corp	Sulphur, LA	590,000	65%	35%			
Westlake Petrochemicals Corp	Sulphur, LA	436,000	100%				
Williams Energy Services	Geismar, LA	567,000	90%	10%			

Estimating the amount of natural gas used by a typical petrochemical facility like an ethylene plant is a very complicated process. These plants, which are constructed at what is referred to as "world class scale," can amount to billions of dollars of investment. Thus, prior to development, a substantial amount of work is conducted in optimizing plant design, including the use of feedstocks. Critical to this analysis is the liquids composition of the ANS gas stream, which is under the producers' control and would be influenced by requirements for gas cycling for EOR as well as by relative prices for various components in the gas stream.

While large ethylene plants can use a significant amount of natural gas, it is important to keep in mind that only the ethane, propanes, and butanes of the gas are actually used for production. One of the byproducts of the cracking process is methane – often referred to as residual gas. In some instances, this unused methane can actually be injected back into the natural gas pipeline.[8]

Given the myriad number of variables associated with estimating natural gas use at a "typical" ethylene plant, we have opted to use a "comparable facilities" approach to estimating potential natural gas usage at facilities located in Louisiana. These facilities and their typical annual natural gas consumption are presented in Table 7.3. These facilitates are all of "world class scale." In addition, one of these facilities is an ethylene and propylene facility owned and operated by Williams Energy.

[8]It is common industry practice to refer to ethylene "crackers" when referring to the production process of converting ethane to ethylene. However, this is a misnomer. Ethylene is not cracked by rather is a product of the cracking process. For a straightforward description of the ethylene production process, see Donald L. Burdick and William L. Leffler. *Petrochemicals in Non-Technical Language*. Houston, Pennwell Books: 1990.

Table 7.3: Typical Gas Usage at Major Ethylene Facilities in Louisiana

Facility	Location	Total Nameplate Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity Is Based					Gas Usage MMcf	Gas Usage MMcf/d	Gas Usage (Mcf/TPY)
			Ethane	Propane	Butane	Naptha	Other			
Condea Vista Co	Westlake, LA	447,000	100%					3,528	9.67	7.89
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%						
Dow Chemical Co**	Plaquemine, LA	680,000	20%	30%		50%		50,000	136.99	42.37
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%				
Dow Chemical Co**	Taft, LA	410,000	25%	25%		50%		7,908	21.67	19.29
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%				20,020	54.85	36.40
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%	13,540	37.10	21.63
Williams Energy Services	Geismar, LA	567,000	90%	10%				6,200	16.99	10.93

** *Combined Plant Totals*

7.3: Expanding Natural Gas Usage at Existing Industrial Facilities

Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. A graph of the historic natural gas consumption for each industrial facility is presented in Figure 7.1.

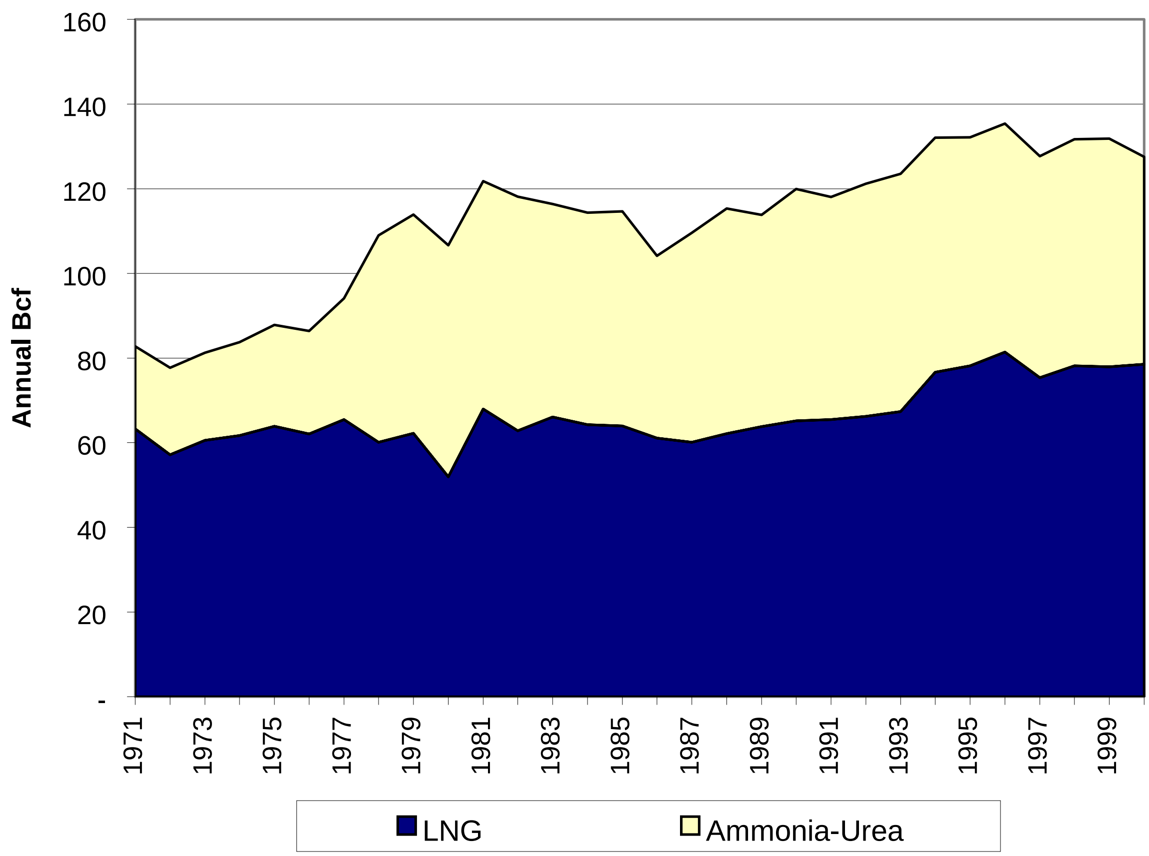

Figure 7.1: Annual LNG and Ammonia-Urea Use of Natural Gas

Source: Alaska Department of Natural Resources.

Phillips and Marathon share ownership in the LNG liquefaction facility and tankers located in Kenai, Alaska. The LNG facility began operating in 1969. The plant consumes 220 million cubic feet of natural gas per day (78 Bcf per year). The facility produces about 1.5 million metric tons of high-methane LNG per year. The LNG is sold to Tokyo Electric and Tokyo Gas companies. Today, the Phillips-Marathon LNG plant supplies approximately one percent of Japan's LNG consumption. The Kenai plant is a baseload LNG facility. Most other U.S. commercial LNG plants are peak saving operations, meaning small LNG plants typically located near utilities. Peak-shaving LNG plants liquefy and store gas delivered by pipeline at low demand periods for later use during peak periods. Baseload plants like the Phillips-Marathon plant in Kenai serve markets that are located far away from sufficient supplies to enable economic deliveries by pipeline. As seen in Figure 7.1, the use of natural gas at the LNG facility has been relatively constant since 1996. Given the steady, long term nature of these contracts, this relatively steady use of natural gas is not unexpected.

The economics of LNG are complicated and dependent upon a number of factors, not the least of which is forecasting the demand for LNG in Asian and world markets, as well as the direction of cost trends in other competing areas around the world. There have been a number of studies of expanded LNG production opportunities in Alaska over the past several years. Developing an alternative to these comprehensive studies was beyond the scope of this study.

However, we have examined the trends in past LNG natural gas usage over the past several years to see if few additional production opportunities exist. As we noted above, the trends in gas usage are relatively stable, and outside year-to-year variations, we see little opportunities to expand production beyond its current levels. Currently, the Kenai LNG facility is operating slightly below its all-time high level of usage of natural gas of 81 Bcf that occurred in 1996. In 2000, LNG uses of natural gas were at 78.5 Bcf, so conceivably, there may be an additional 2.8 Bcf of additional usage at the facility.

We have also examined the potential use of natural gas by the state's other large industrial natural gas user: The Agrium ammonia-urea plant in Southcentral Alaska. This plant produces anhydrous ammonia (NH_3) and urea fertilizer based on technology dating back to the 1960s. Plant output capacity is approximately two million tons per year, divided roughly between ammonia and urea. Natural gas (methane) is combined with nitrogen at high temperatures to produce NH_3 plus carbon dioxide and sulfur by-products. NH_3 is the feedstock for many other products, including nitrogen-based urea fertilizer. Ammonia is sold in separate markets and is an intermediate product used to make urea. Sometimes the relative price of urea is low. In such cases, it many be profitable to intensify ammonia production and reduce or completely halt urea production. Nearly all plant output is exported to markets in Southeast Asia, primarily Thailand.

Based upon information included in the Manufacturing and Industrial Plant Database (MIPD), published by The HIS Energy Group, at about 49 Bcf per year, the Agrium plant currently operates at about 80 percent of capacity. The high point for natural gas usage for the facility, as seen in Figure 7.1, was in 1996 when the facility used about 56 Bcf for that year. The facility consumed less natural gas from year to year since 1993. Hence, there appear to be short run opportunities for increased gas usage of up to 7.2 Bcf per year.

In a recent article published by *Petroleum News Alaska*, Agrium noted that they were interested in expanding its Cook Inlet operations, which could translate into additional annual usage of 30 Bcf per year.[9] Chris Tworek, Vice President of Supply for Agrium noted that, in order for the facility to expand production, its natural gas input prices would have to be competitive with global prices, which range between 75 cents to $1.00 per MMBtu. The potential for Agrium to increase natural gas usage by 30 Bcf per year is unlikely to occur a prices prevailing in the Cook Inlet Basin today but should be considered in a long run forecast of new industrial uses of natural gas in Alaska.

[9]Kristen Nelson. “Agrium Would Like to Grow Cook Inlet Operation.” *Petroleum News Alaska*. (November 25, 2001): A14.

CHAPTER 8: NEW POWER GENERATION OPPORTUNITIES

The Alaska power system can be segregated into three categories: (1) interconnected utilities in the Railbelt; (2) small, isolated, non-interconnected utilities in the Bush; and (3) mid-size, non-interconnected utilities like Kodiak Electric Association and Copper Valley Electric Association, Inc.

The Alaska Systems Coordinating Council (ASCC) provides oversight and coordination of statewide electric utility operations for reliability purposes. The ASCC is comprised of 17 electric utilities, three state agencies, and a federal agency. Nine ASCC members are interconnected in the railbelt region to serve the Anchorage Bowl, Fairbanks area, and the Kenai Peninsula. These members account for approximately 75 percent of the utility generating capacity in Alaska.

The ASCC notes that, "the Alaska electric system is truly isolated and does not have a transmission grid as normally defined." The transmission systems that do exist are commonly referred to as "isolated radial single lines." There is no connection with transmission grids outside of Alaska. Many of the transmission system issues associated with the lower 48 simply do not exist in Alaska.[1]

Power transmission interties on the northern and southern ends of the railbelt system between Fairbanks and Kenai Peninsula improve reliability by providing a second set of transmission links between Healy and Fairbanks in the north and between Anchorage and the Kenai Peninsula to the south. The Northern Intertie route selection process is complete and construction plans are finalized. This line will be constructed for 230 kilovolts (kV), but operated at 138 in the near term. The line is expected to be fully operational within three years. The Southern Intertie route selection process, including its associated environmental impact statement and findings, is underway.

The majority of Alaska's 250 rural towns and villages are not interconnected. The rural town and village power systems typically rely on a single local diesel or fuel oil generating plant. For these areas of the state, power cost and generator reliability (as opposed to transmission reliability) are of the greatest importance. According to the ASCC, maintenance programs, system upgrades, and applying new small-scale power generation technologies are a high priority.

One of the more recent investigations of the potential for new power generation in Alaska, as well as increasing the efficiency of existing power generation stations, was conducted by CH2M Hill in a report prepared for the Regulatory

[1]These include issues associated with interconnection rules and costs, transmission governance and pricing, long term transmission planning for wholesale competition, and the development of Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).

Commission of Alaska (RCA) and the Alaska Legislature.[2] This report, hereafter referred to as the CH2M Hill report, is a comprehensive examination of electric restructuring issues, how they relate to Alaska's power industry, and the potential costs and benefits of moving forward with greater competition. The study notes that "…there is no restructuring model in existence today that would work in rural Alaska among the villages and cities that are not interconnected to the Railbelt system."

The report offers three alternative pathways for the future development of Alaska's power system:

(1) The State can "fix the potholes" in its current system;

(2) The State can choose a scenario that focuses on rapidly "commoditizing kilowatts" in an effort to capture wholesale power market benefits; or

(3) The State can choose a course of "controlled evolution," transitioning the current regulated system into a more competitive and diverse marketplace.

The empirical analysis conducted in the CH2M Hill report included a "least cost dispatch" model for the state's railbelt utilities. Least cost multi-area dispatch models are common tools that are used in the lower 48 to examine the efficiency opportunities for coordinated least cost dispatch of power generation facilities. The approach, in its most simple form, stacks each generator by the least cost generation facility to its most expensive. The intersection of demand to this least-cost developed supply curve represents the amount of power generation that would be dispatched to the market, as well as the market clearing price for power.

While the CH2M Hill report findings were modestly in favor of moving forward with a limited form of competition in Alaska, the RCA Staff was somewhat more critical of the idea. In comments attached to Order 7 in Docket Number R-97-10, the Commission Staff recommended that "… the gains from restructuring appear to be modest, while risks are potentially considerable. Accordingly, Staff recommends that no policy action be taken at this time to restructure Alaska's Railbelt utility system."[3]

With regards to the costs of moving forward with restructuring, the Staff comments noted that:

[2] Karl Robago, Tom Feiler, Floyd Damron, and Deanana Gamle. *Study of Electric Utility Restructuring in Alaska*. Report to the Alaska Public Utilities Commission and the Alaska State Legislature. June 30, 1999.

[3] Comments of the RCA Staff, Attachment to Order No. 7, Docket R-97-10, *In the Matter of Regulations Defining the Future Market Structure of Alaska's Electric Industry*. June 22, 2001.

> The Railbelt at present does not appear to have the infrastructure – either in diversity of generator ownership, or in transmission redundancy – to support robust competition. The presence of long-term fuel supply contracts may predetermine competitive outcomes if retail competition is introduced in the near term. It appears that Alaska has little gain, and potentially much to lose, by any quick movement to retail competition. The next five to ten years will see resolution of a number of important issues that will profoundly affect the economics of electricity production in the Railbelt.[4]

The issue of electric restructuring is important to the future in-state opportunities for increased gas consumption. In the lower 48, the advent of wholesale and retail competition has resulted in an explosion of new merchant power plant construction. These merchant facilities are typical simple cycle (CT) or combined-cycle[5] (CC) gas generating units. According to a U.S. Department of Energy study, about 50 percent of the future growth in natural gas demand will come from serving the fuel requirements of the power generation facilities.[6]

However, there are a number of factors that dampen the possibilities that Alaska could experience an explosion in new gas fired generation resulting from competition. The RCA Staff raise a number of important issues with regards to both competition and the need for new power generation. Some of the factors that limit the possibilities of competition and new competitive power generation include:

- Large reserve capacity margins that considerably delay when new units to the Railbelt need to be added;

- Utilities that are primarily customer-owned; and

- The prevalence of long term wholesale electricity and fuel contracts.[7]

Referencing an earlier Black and Veatch study on power generation in Alaska, the RCA Staff notes that the State does not have a forecast power generation capacity addition need until the year 2014.[8]

Given the RCA Staff comments and our own analysis of past power demand trends in Alaska, we have limited our analysis of new potential gas generation to

[4]Commission Staff Comments at 2.

[5]A combined cycle generator is one that includes initial-stage turbine generation with a heat recovery unit for additional generation to enhance overall power generation efficiency.

[6]US Department of Energy, Annual Energy Outlook to 2020. Washington: Energy Information Administration, Table A.13.

[7]Commission Staff Comments at 10.

[8]Commission Staff Comments at 11, referencing the Black and Veatch Power Pooling Study at 5-1 conducted on the behalf of the RCA, 1998.

two sources: first, fuel switching by the Bush utilities and larger non-interconnected systems in Alaska; and second, a new power generation facility located in close proximity to the proposed Alaska Highway Route (AHR). We will assume that the AHR example could be translated into a “gas by wire” application, where power generated from this facility could be moved to neighboring areas to displace existing on-site power generation.

8.1: Fuel Switching Opportunities for Bush and Larger Non-Interconnected Systems

Our analysis of fuel switching opportunities for power generation facilities is similar to that in our residential geographic proximity analysis. There is, however, a difference in how the power plant information is referenced to geographic locations. Due to the unavailability of specific geo-referencing information on many of the smaller power generating units, we aggregated generators (oil and diesel) by ZIP codes and used the U.S. Census-developed SIP code digital boundaries in the overlay procedures. Figure 8.1 maps all power generation facilities in Alaska based upon this method, while Figure 8.2 highlights those facilities that are currently being fired by fuel oil or diesel fuel. The quantitative results of the proximity analysis have been presented in Tables 8.1, 8.2, and 8.3 (capacity by region). The natural gas usage associated with switching these units are provided in Table 8.4 and 8.5.

The geographic distribution of oil and diesel fired generators are different from those conducted earlier for residential customers. In particular, 34.2 percent of the potential fuel switching generating capacity is located within five miles of the proposed AHR (see Table 8.2). Some 202 MWs of capacity are located in the Interior section, 12.9 MWs of capacity is located within the Southcentral region, and 2.5 MWs are located in the Southeastern region (see Table 8.1).

The largest opportunities for fuel switching through power generation are in the interior region – primarily in Fairbanks. Some 96 percent of the capacity available for fuel switching is located in this region, and within 5 miles of the AHR.

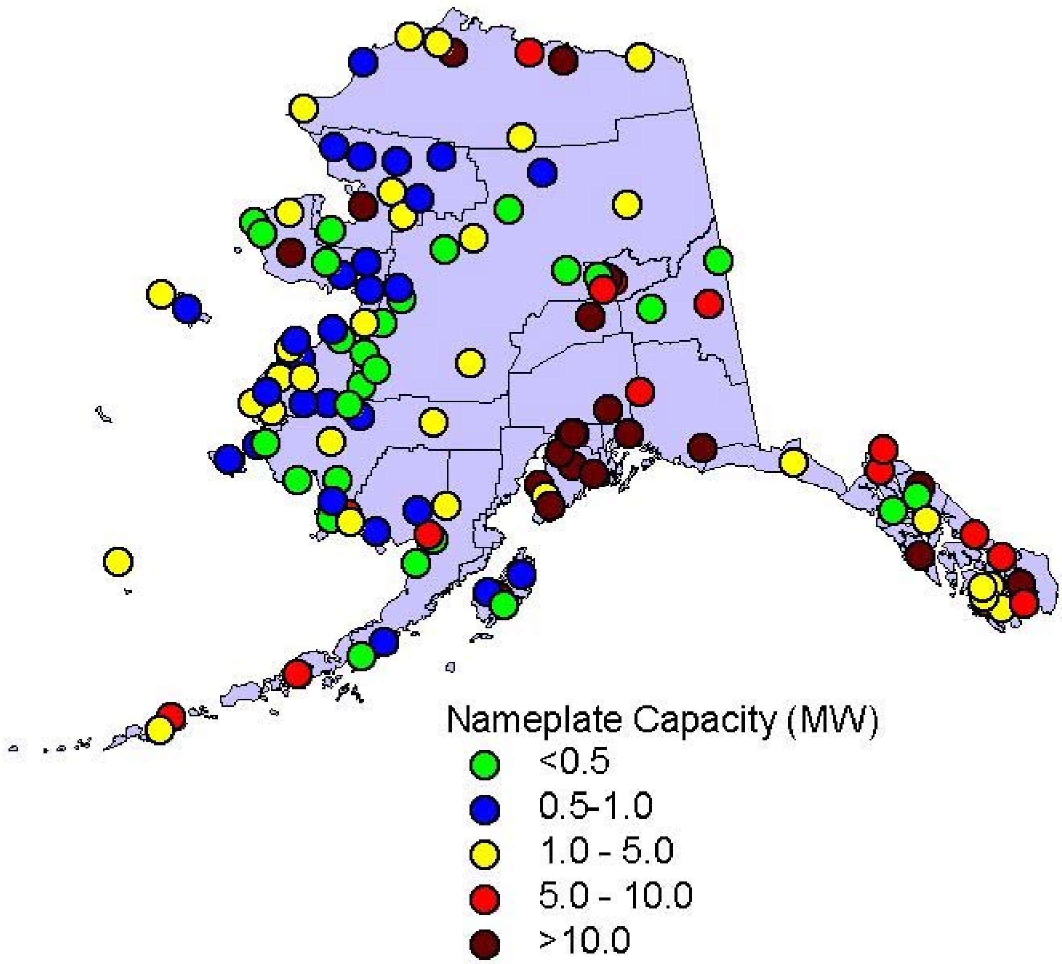

Figure 8.1: Total Power Generation Capacity by Location

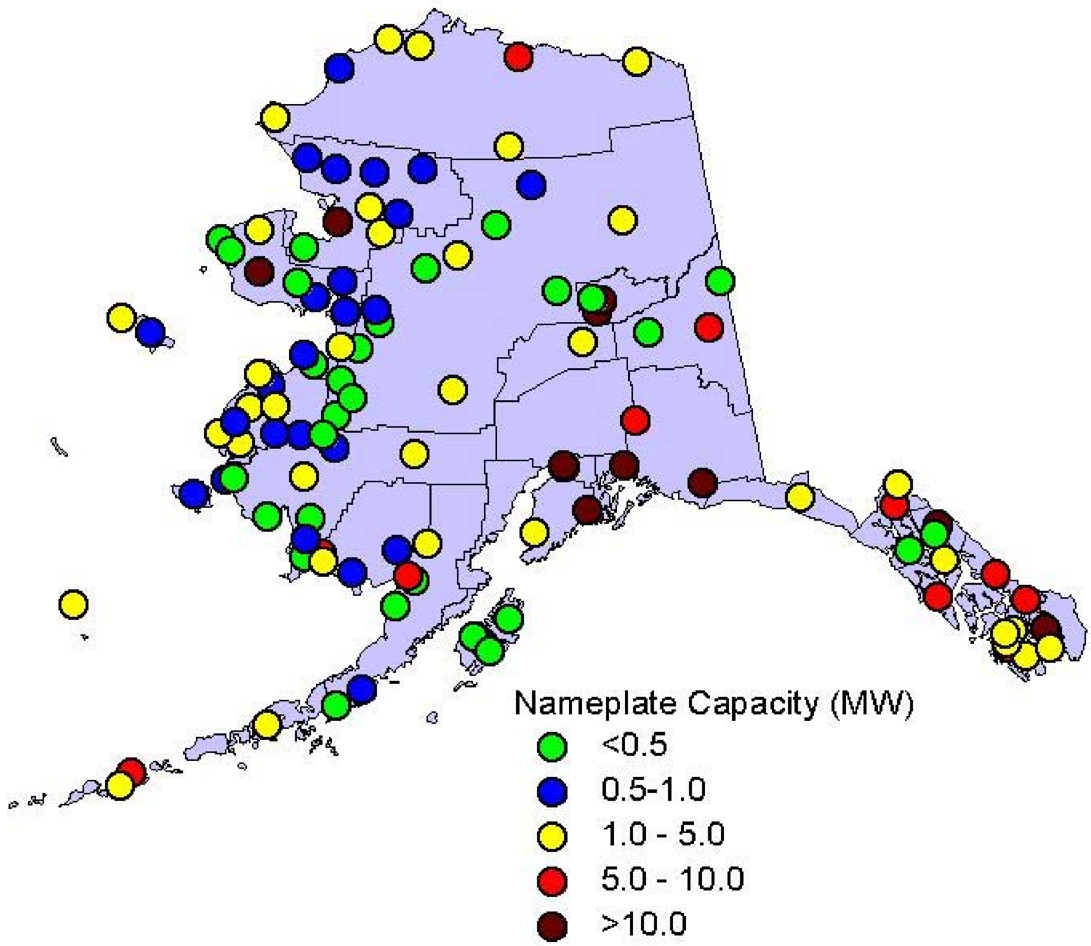

Figure 8.2: Oil and Diesel Fired Generation Capacity by Location

Table 8.1: Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	760	760
	Beyond 20 miles	0	0	0	0	48,228	48,228
	Total	0	0	0	0	48,988	48,988
Interior	Within 5 miles	0	0	192,900	192,900	9,275	**202,175**
	Within 10 miles	0	0	192,900	192,900	9,275	202,175
	Within 15 miles	0	0	192,900	192,900	9,275	202,175
	Within 20 miles	0	0	192,900	192,900	9,275	202,175
	Beyond 20 miles	0	0	0	0	9,294	9,294
	Total	0	0	192,900	192,900	18,569	211,469
South Central	Within 5 miles	0	0	0	2,536	10,456	**12,992**
	Within 10 miles	0	0	10,102	15,138	10,456	25,594
	Within 15 miles	0	0	10,102	15,138	10,456	25,594
	Within 20 miles	0	0	10,102	15,138	48,366	63,504
	Beyond 20 miles	0	10,403	10,403	10,403	12,600	23,003
	Total	0	10,403	20,505	25,541	60,966	86,507
South East	Within 5 miles	2,500	2,500	2,500	2,500	0	**2,500**
	Within 10 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 15 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 20 miles	2,500	2,500	11,130	11,130	0	11,130
	Beyond 20 miles	97,600	136,058	162,178	166,008	3,586	169,594
	Total	100,100	138,558	173,308	177,138	3,586	180,724
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	28,775	29,205	78,755	107,960
	Total	0	0	28,775	29,205	78,755	107,960
Alaska Total	Within 5 miles	2,500	2,500	195,400	197,936	19,731	217,667
	Within 10 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 15 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 20 miles	2,500	2,500	214,132	219,168	58,401	277,569
	Beyond 20 miles	97,600	146,461	201,356	205,616	152,463	358,079
	Total	100,100	148,961	415,488	424,784	210,864	635,648

Table 8.2: Relative Frequency Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (Percent of Total)

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	1.6%	1.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	98.4%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.2%	91.2%	4.4%	**95.6%**
	Within 10 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 15 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 20 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	4.4%	
	Column Total	0.0%	0.0%	91.2%	91.2%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	2.9%	12.1%	15.0%
	Within 10 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 15 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 20 miles	0.0%	0.0%	11.7%	17.5%	55.9%	73.4%
	Beyond 20 miles	0.0%	12.0%	12.0%	12.0%	14.6%	
	Column Total	0.0%	12.0%	23.7%	29.5%		100.0%
South East	Within 5 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 10 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 15 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 20 miles	1.4%	1.4%	6.2%	6.2%	0.0%	6.2%
	Beyond 20 miles	54.0%	75.3%	89.7%	91.9%	2.0%	
	Column Total	55.4%	76.7%	95.9%	98.0%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	26.7%	27.1%	72.9%	
	Column Total	0.0%	0.0%	26.7%	27.1%		100.0%
Alaska Total	Within 5 miles	0.4%	0.4%	30.7%	31.1%	3.1%	**34.2%**
	Within 10 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 15 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 20 miles	0.4%	0.4%	33.7%	34.5%	9.2%	43.7%
	Beyond 20 miles	15.4%	23.0%	31.7%	32.3%	24.0%	
	Column Total	15.7%	23.4%	65.4%	66.8%		100.0%

Table 8.3: Summary of Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

	Far North	Interior	Southcentral	Southeast	Southwest	Alaska
Within 5 miles of EPNGS	0	0	0	100,100	0	100,100
Within 5 miles of AHR	0	202,175	12,992	2,500	0	217,667
Within 10 miles of EPNGS	0	0	10,403	138,558	0	148,961
Within 10 miles of AHR	0	**202,175**	25,594	2,500	0	230,269
Within 15 miles of EPNGS	0	192,900	20,505	173,308	28,775	415,488
Within 15 miles of AHR	0	202,175	25,594	2,500	0	230,269
Within 20 miles of EPNGS	0	192,900	25,541	177,138	29,205	424,784
Within 20 miles of AHR	760	202,175	63,504	11,130	0	277,569
Beyond 20 miles of both	48,228	9,294	12,600	3,586	78,755	152,463

Tables 8.4, 8.5, and 8.6 present the gas usage associated with each of the power generation facilities identified in earlier capacity tables. As presented in the bottom right hand corner of Table 8.4, the total increase in gas usage, associated with switching power generation fuels, is 32.8 Bcf per year. The majority of the new gas usage opportunity rests within the Interior section of Alaska, primarily Fairbanks (30.28 Bcf).

Table 8.4: Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	95	95
	Beyond 20 miles	0	0	0	0	4,348	4,348
	Total	0	0	0	0	4,443	4,443
Interior	Within 5 miles	0	0	28,896	28,896	1,388	**30,284**
	Within 10 miles	0	0	28,896	28,896	1,388	30,284
	Within 15 miles	0	0	28,896	28,896	1,388	30,284
	Within 20 miles	0	0	28,896	28,896	1,388	30,284
	Beyond 20 miles	0	0	0	0	1,185	1,185
	Total	0	0	28,896	28,896	2,574	31,469
South Central	Within 5 miles	0	0	0	565	1,666	2,231
	Within 10 miles	0	0	1,670	2,732	1,666	4,398
	Within 15 miles	0	0	1,670	2,732	1,666	4,398
	Within 20 miles	0	0	1,670	2,732	6,398	9,130
	Beyond 20 miles	0	1,488	1,488	1,488	2,103	3,592
	Total	0	1,488	3,158	4,220	8,502	12,722
South East	Within 5 miles	285	285	285	285	0	285
	Within 10 miles	285	285	285	285	0	285
	Within 15 miles	285	285	285	285	0	285
	Within 20 miles	285	285	1,315	1,315	0	1,315
	Beyond 20 miles	14,207	19,582	23,444	23,947	407	24,354
	Total	14,492	19,867	24,759	25,262	407	25,669
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	5,161	5,215	10,140	15,355
	Total	0	0	5,161	5,215	10,140	15,355
Alaska Total	Within 5 miles	285	285	29,181	29,746	3,054	**32,800**
	Within 10 miles	285	285	30,850	31,912	3,054	34,967
	Within 15 miles	285	285	30,850	31,912	3,054	34,967
	Within 20 miles	285	285	31,880	32,942	7,881	40,823
	Beyond 20 miles	14,207	21,071	30,094	30,650	18,184	48,834
	Total	14,492	21,355	61,974	63,592	26,065	89,657

Table 8.5: Relative Frequency Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (Percent of Total)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	2.1%	2.1%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	97.9%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 10 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 15 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 20 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	3.8%	
	Column Total	0.0%	0.0%	91.8%	91.8%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	4.4%	13.1%	17.5%
	Within 10 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 15 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 20 miles	0.0%	0.0%	13.1%	21.5%	50.3%	71.8%
	Beyond 20 miles	0.0%	11.7%	11.7%	11.7%	16.5%	
	Column Total	0.0%	11.7%	24.8%	33.2%		100.0%
South East	Within 5 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 10 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 15 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 20 miles	1.1%	1.1%	5.1%	5.1%	0.0%	5.1%
	Beyond 20 miles	55.3%	76.3%	91.3%	93.3%	1.6%	
	Column Total	56.5%	77.4%	96.5%	98.4%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	33.6%	34.0%	66.0%	
	Column Total	0.0%	0.0%	33.6%	34.0%		100.0%
Alaska Total	Within 5 miles	0.3%	0.3%	32.5%	33.2%	3.4%	36.6%
	Within 10 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 15 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 20 miles	0.3%	0.3%	35.6%	36.7%	8.8%	45.5%
	Beyond 20 miles	15.8%	23.5%	33.6%	34.2%	20.3%	
	Column Total	16.2%	23.8%	69.1%	70.9%		100.0%

Table 8.6: Summary of Usage Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

	Far North	Interior	South Central	South East	South West	Alaska
Within 5 miles of EPNGS	0	0	0	14,492	0	14,492
Within 5 miles of AHR	0	30,284	2,231	285	0	**32,800**
Within 10 miles of EPNGS	0	0	1,488	19,867	0	21,355
Within 10 miles of AHR	0	30,284	4,398	285	0	34,967
Within 15 miles of EPNGS	0	28,896	3,158	24,759	5,161	61,974
Within 15 miles of AHR	0	30,284	4,398	285	0	34,967
Within 20 miles of EPNGS	0	28,896	4,220	25,262	5,215	63,592
Within 20 miles of AHR	95	30,284	9,130	1,315	0	40,823
Beyond 20 miles of both	4,348	1,185	2,103	407	10,140	18,184

8.2: Electric Power Generation in the Interior

The electric power sector in Fairbanks has the potential for the largest use of ANS gas in the area. This sector includes Golden Valley Electric Association (GVEA), Aurora Energy, the University of Alaska Fairbanks, Ft Wainwright and Eielson AFB. The power plants for these facilities generate electricity from coal and fuel oil. GVEA is the largest power generator in the region. It operates two 60-megawatt oil-fired plants in North Pole plus several smaller, sub-station facilities. Golden Valley operates a coal-fired plant in Healy and owns partial interest in the Bradley Lake Hydro-electric facility.[9] Utility managers responded to a 1997 DNR survey regarding the potential for conversion to natural gas. The results of the survey are summarized in Table 8.7.

[9]GVEA obtained the electric customers and a diesel-fired combustion turbine from Fairbanks Municipal Utility System in 1997. Aurora Energy LLP (wholly owned by Usibelli Coal Mines (UCM)) was formed which took over Fairbanks Municipal Utility System's coal burning plant. GVEA contracted with Aurora Energy to purchase all electrical energy generated from these units. GVEA also purchases power directly from Chugach Electric Association, Inc. and Municipal Light and Power in Anchorage.

Table 8.7: Fairbanks North Star Borough Electric Power Survey

	Coal					Fuel Oil				
			Rate of Gas Consumption After Conversion					Rate of Gas Consumption After Conversion		
	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low
	$/Ton	$/MmBtu	Mmcf/d	Mmcf/d	Mmcf/d	$/Gallon	$ per MmBtu	Mmcf/d	Mmcf/d	Mmcf/d
FMUS[1]	$44	$2.50	5	5	5	$0.71	$2.50	0.1	n/a	n/a
GVEA	$23.40	$1.50	7	7	7	$0.45	$2.50	12	14	10
FT. Wainwright	$46.22	$3.00	7.8	11.6	3.6	n/a	n/a	n/a	n/a	n/a
Eielson AFB	n/a	$3.60	6.4	12.8	5.01	n/a	n/a	n/a	n/a	n/a
UAF	$44	$2.82	2.5	3.2	0.5	$0.89	$6.34	0.14	1	0

[1] The Fairbanks Municipal Utility System assets were acquired by GVEA and Aurora Power in 1999.

In general, utility managers were receptive to a natural gas alternative to the low BTU coal. Several utility managers expressed a preference for having a choice among fuel feedstock. However, even if inexpensive, base-load natural gas were available on a sustainable basis, 100 percent plant conversion would be unlikely because of the high upfront investment, long-term contractual commitments with existing fuel suppliers, and the desirability of multiple fuel systems. Respondents indicated the maximum natural gas price that would compete with existing fuels and permit conversion ranges between $1.50 and $3.60 per MmBtu. An initial estimate of potential conversions based upon this survey, at different penetration rates for the year 2009, has been provided in Table 8.8

Table 8.8: Potential Natural Gas Usage for Power Generation in the Fairbanks North Star Borough in 2009

Line No		Formula		Low	Medium	High
1	**Electric Power - Civilian**[1]					
2	Projected Maximum Electricity Load (Bcf per Year)		10.3			
3	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
4	**Potential Civilian Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 2 x Line 3		**2.6**	**5.2**	**8.6**
5	**Electric Power - Military**[2]					
6	Projected Maximum Electricity Load (Bcf per Year)		2.7			
7	Penetration Rate in 2009[3]			25.0%	50.0%	83.0%
8	**Potential Military Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 6 x Line 7		**0.7**	**1.3**	**2.2**
9	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 4 & 8)		**3.3**	**6.5**	**10.8**

Table Notes:

1 83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study,* 1989.

2 We assume that, at most, 50% of military electric power requirements would be available for gas-fired generation.

3 Golden Valley Electric Association, Aurora Energy, and the University of Alaska Fairbanks.

Based on the results of this ADNR survey and other information, an alternative estimate of potential annual natural gas demand for electric power generation was prepared in Table 8.9. The results indicate that natural gas consumption for civilian electric power requirements could be approximately 9.3 Bcf per year. Military power requirements, which are served primarily with coal-fired generation, would be an additional 5.6 Bcf per year. The daily swings for heating use were assumed to be 2 ½ times the average usage rates, which is approximately the same as the maximum deliverability swings experienced in the Enstar system.

Table 8.9: Fairbanks Area Electric Power Plants and Estimated Natural Gas Usage[1]

	Golden Valley Electric Association	Aurora Energy, LLP	University of Alaska Fairbanks	Military[2]	Total
Coal Consumption					
Tons per Year	170,000	130,000	60,000	360,000	720,000
Million Btus per Year[3]	2,516,000	1,924,000	888,000	5,328,000	10,656,000
Oil Consumption					
Gallons per Year (x1000)	28,000		280		28,280
Million Btus per year[4]	3,948,000		39,480		3,987,480
Coal and Oil Combined Total MMBTUs	6,464,000	1,924,000	927,480	5,328,000	14,643,480
Natural Gas equivalent (Bcf per Year)	6.5	1.9	0.9	2.7	12.0
Non-Military			9.3		

[1] Estimated from published 1995 statistics, responses to a utility survey conducted by DNR in 1997 and private conversations with utility managers.
[2] Estimates, include Fort Wainwright and Eielson Air Force Base.
[3] Based on conversion: 1 ton of coal = 14.8 million Btus.
[4] Based on conversion: 1 gallon of heating oil = 141,000 Btus. Note that oil-fired power generation is highly variable.
[5] We assume that 50% of military power requirements would be available for gas-fired generation.

These above estimates are build on the maintained assumption that the cost of gas delivered to the power plants and the cost of furnace and generator system conversion to natural gas, would be competitive with other energy alternatives.

8.3: Gas by Wire Application

We also examine a new gas fired power generation facility near Fairbanks close to the AHR. In effect, we relocate regional gas-fired power generation to Fairbanks and distribute power *by wire* to communities in the Interior Region. For this analysis, we assumed a new 250 MW facility, at an installed cost of $750/kW. This facility was assumed to be operating at a heat rate of 6,000 BTUs per kWh generated. A power plant's heat rate measures its thermal efficiency in terms of the amount of BTUs of energy used to produce one kWh. The results of the analysis are presented in Table 8.10 below.

The results from the preliminary analysis are encouraging. Table 8.10 presents three different generation cost analyses based upon different fuel cost assumptions. We have examined new generation costs from a range taken by the three larger railbelt utilities with gas-fired generation. The top of the table includes the operating and cost assumptions used in the analysis. The bottom portion of the table presents two different cost estimates: total dispatch costs and total levelized costs.

Total dispatch costs are essentially the average variable costs of a generation facility and in most instances under economic (or least cost) dispatch, will dictate the order in which a power generation facility is run. Total levelized costs, on the other hand, are the total costs of the facility, including capital, expressed in per kWh term.[10] These costs are presented at the bottom of Table 8.10 and in all instances are relatively competitive from an absolute level.

[10]An annual carrying factor has been developed to estimate the return on and of the capital investment as well as any associated taxes.

Table 8.10: Total Dispatch and Levelized Cost for Gas By Wire Application

General Plant Cost and Operating Assumptions					
Capacity Factor	0.95			Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000			Annual Carrying Cost	$22,414,158
Heat Rate	6,000			Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	700			Deprecation, Years	30
Capacity (kW)	250,000			Rate of Return	10.16%
Total Installed Cost	175,000,000			Taxes	38.71%
Capital Cost; $/kW/Yr	23				
New Plant at MPL Gas Cost		**New Plant at CEA Gas Cost**		**New Plant at GVEA Gas Cost**	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00
Cost of Gas	$1.86	Cost of Gas	$1.27	Cost of Gas	$3.18
Total Annual Gas Cost	$23,218,380	Total Annual Gas Cost	$15,828,444	Total Annual Gas Cost	$39,711,544
Average Variable Fuel Cost	$0.01116	Average Variable Fuel Cost	$0.00761	Average Variable Fuel Cost	$0.01909
Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500
Total Dispatch Cost	$0.01616	Total Dispatch Cost	$0.01261	Total Dispatch Cost	$0.02409
Total Levelized Cost	$0.02693	Total Levelized Cost	$0.02338	Total Levelized Cost	$0.03486

Next, we compare the dispatch cost of the hypothetical, new generation facility with other railbelt utility generation facilities. The objective our our analysis is to explore how well the new gas-by-wire application compares with existing generating units from the standpoint of dispatch costs. In short run hourly power markets, generation facilities are dispatched according to short run marginal costs. This least cost dispatch ranks facilities from the lowest marginal cost to the highest marginal costs. Low cost units are typically run first, with higher cost units being dispatched up to the point where all demand is met.

Unit dispatch costs are usually comprised of average variable fuel costs as well as average variable operation & maintenance (O&M) costs. Unit dispatch costs, on a per MWh basis, are the sum of these two costs. The railbelt generation facilities, and their operating and cost characteristics, are presented in Table 8.11, with summaries given at the bottom for the Railbelt as a whole and the three major Southcentral electric utilities. The results for the new gas-by-wire applications are also shown at the bottom of Table 8.11. The results indicate that existing gas-fired generation in Alaska is relatively inefficient compared to a new gas-by-wire application. Heat rates, (or the thermal efficiency) of existing Railbelt gas fired generation ranges from 13,000 Btus/kWh to almost 16,000 Btus per kWh. New combined cycle generation typical generate at efficiencies of around 6,000 Btus per kWh. In making a comparison between these efficiencies, lower heat rates entail more efficient units. In other words, a lower heat rate entails that a unit uses less energy to make one kWh of electricity.

The new gas-by-wire application is competitive with many of these existing generation resources currently being dispatched in the railbelt utility system. In most every instance, the new gas-by-wire application beats existing gas-fired generation in the region.

A note of caution is in order at this juncture. We have concluded that under limited, short-run conditions, the new gas-by-wire application is more efficient and cost-effective than existing power generation. However, these estimates do not include the costs associated with supplying (transporting) the natural gas to the new gas-by-wire application, nor do they include any new power transmission costs associated with moving the electrical output from this facility. The costs of supplying natural gas to this potential application, as well as several others identified in earlier chapters of our report, are explored in Chapter 9. Our subsequent analysis will show that the new transportation (gas and power) infrastructure costs of putting this facility into service would shift the dispatch cost into the $28.42/Mwh to $36.34/MWh range.

Table 8.11: Railbelt Utility Generation Facilities Dispatch Cost Relative to Gas by Wire Application

Plant	Company	Fuel Type	Capacity (MW)	Maximum Capacity Factor	Ownership & Availability Adjustment	Fuel Cost ($/MBTU)	Heat Rate (BTU/kWh)	Generation Amount (kWh)	Fuel Costs ($/MWh)	Non-Fuel O&M ($/MWh)	Dispatch Cost ($/MWh)
MLP Plant 1, Unit 1	MLP	Gas	16.8	97%	16	$1.86	14,590	142,752,960	$27.14	$2.00	$29.14
MLP Plant 1, Unit 2	MLP	Gas	16.8	97%	16	$1.86	13,980	142,752,960	$26.00	$2.00	$28.00
MLP Plant 1, Unit 3	MLP	Gas	19.5	97%	19	$1.86	14,371	165,695,400	$26.73	$2.00	$28.73
MLP Plant 1, Unit 4	MLP	Gas	34.1	97%	33	$1.86	17,324	289,754,520	$32.22	$2.00	$34.22
MLP Plant 2, Unit 5	MLP	Gas	38.4	97%	37	$1.86	10,106	326,292,480	$18.80	$2.00	$20.80
MLP Plant 2, Unit 7/6	MLP	Gas	109.5	97%	106	$1.86	8,527	930,443,400	$15.86	$2.00	$17.86
MLP Plant 2, Unit 8	MLP	Gas	87.6	97%	85	$1.86	11,577	744,354,720	$21.53	$2.00	$23.53
Beluga Unit 1	CEA	Gas	16.7	93%	16	$1.17	16,924	136,051,560	$19.80	$2.00	$21.80
Beluga Unit 2	CEA	Gas	16.7	98%	16	$1.17	17,320	143,366,160	$20.26	$2.00	$22.26
Beluga Unit 3	CEA	Gas	66.9	96%	64	$1.17	12,288	562,602,240	$14.38	$2.00	$16.38
Beluga Unit 5	CEA	Gas	71.0	97%	69	$1.17	12,537	603,301,200	$14.67	$2.00	$16.67
Beluga Unit 6	CEA	Gas	74.0	90%	67	$1.17	12,743	583,416,000	$14.91	$2.00	$16.91
Beluga Unit 7	CEA	Gas	74.0	95%	70	$1.17	13,172	615,828,000	$15.41	$2.00	$17.41
Beluga Unit 6-8	CEA	Gas	101.5	90%	91	$1.17	9,372	800,226,000	$10.97	$2.00	$12.97
Beluga Unit 7-8	CEA	Gas	101.5	90%	91	$1.17	9,149	800,226,000	$10.70	$2.00	$12.70
Bernice Lake 2	CEA	Gas	19.0	100%	19	$1.38	14,817	166,440,000	$20.45	$2.00	$22.45
Bernice Lake 3	CEA	Gas	28.0	93%	26	$1.38	13,512	228,110,400	$18.65	$2.00	$20.65
Bernice Lake 4	CEA	Gas	28.0	95%	27	$1.38	13,715	233,016,000	$18.93	$2.00	$20.93
International 1	CEA	Gas	15.0	90%	14	$1.38	15,992	118,260,000	$22.07	$2.00	$24.07
International 2	CEA	Gas	15.0	90%	14	$1.38	17,384	118,260,000	$23.99	$2.00	$25.99
International 3	CEA	Gas	19.0	89%	17	$1.38	15,030	148,131,600	$20.74	$2.00	$22.74
Soldotna 1	CEA	Gas	39.0	99%	39	$1.38	11,401	338,223,600	$15.73	$2.00	$17.73
Chena 6	GVEA	HAGO	29.0	95%	28	$3.40	12,256	241,338,000	$41.67	$0.30	$41.97
Zehnder EMD 5	GVEA	HAGO	2.6	99%	3	$3.21	25,679	22,548,240	$82.43	$8.24	$90.67
Zehnder EMD 6	GVEA	HAGO	2.6	99%	3	$3.21	27,679	22,548,240	$88.85	$8.24	$97.09
Zehnder GT 1	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
Zehnder GT 2	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
North Pole 1	GVEA	HAGO	56.7	95%	54	$3.00	9,751	471,857,400	$29.25	$4.80	$34.05
North Pole 2	GVEA	HAGO	59.3	92%	55	$3.00	9,154	477,910,560	$27.46	$4.80	$32.26
Healy 1	GVEA	Coal	25.0	91%	23	$1.36	13,995	199,290,000	$19.03	$11.20	$30.23
Healy D 1	GVEA	HAGO	2.6	95%	2	$3.21	11,451	21,637,200	$36.76	$8.24	$45.00
Bradley Lake -- GVEA	GVEA	Hydro	15.2	40%	6	$0.00	1	52,887,974	$0.00	$2.16	$2.16
Bradley Lake -- HEA	GVEA	Hydro	10.8	43%	5	$0.00	1	41,138,397	$0.00	$2.16	$2.16
Bradley Lake -- ML&P	MLP	Hydro	23.3	44%	10	$0.00	1	90,332,078	$0.00	$2.16	$2.16
Ekultna	MLP	Hydro	21.3	40%	9	$0.00	1	74,944,936	$0.00	$2.16	$2.16
Bradley -- Chugash	CEA	Hydro	40.7	42%	17	$0.00	1	151,283,658	$0.00	$2.16	$2.16
Ekultna Chugash	CEA	Hydro	18.7	37%	7	$0.00	1	61,318,108	$0.00	$2.16	$2.16
Cooper Lake 1	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Cooper Lake 2	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Railbelt Average				**84%**		**$1.51**	**11,152**				**$24.69**
MLP Average -- All Generation				**85%**		**$1.45**	**10,053**				**$20.73**
CEA Average -- All Generation				**82%**		**$1.00**	**10,808**				**$15.60**
GVEA Average -- All Generation				**86%**		**$2.44**	**12,644**				**$43.62**
MLP Average -- Gas Only				**97%**		**$1.86**	**12,925**				**$26.04**
CEA Average -- Gas Only				**94%**		**$1.27**	**13,690**				**$19.44**
GVEA Average -- Gas Only				**97%**		**$3.18**	**15,636**				**$55.66**
New Gas-By Wire Application -- MLP Gas Cost				**95%**		**$1.86**	**6,000**				**$16.16**
New Gas-By Wire Application -- CEA Gas Cost				**95%**		**$1.27**	**6,000**				**$12.61**
New Gas-By Wire Application -- GVEA Gas Cost				**95%**		**$3.18**	**6,000**				**$24.09**

CHAPTER 9: COST ESTIMATES OF SUPPLYING NATURAL GAS TO NEW OR EXPANDED SERVICE OPPORTUNITIES

9.1: Introduction

In the earlier chapters of our report, we identified a number of new opportunities for increased in-state natural gas usage. The objective of this chapter is to explore a number of these narrowly defined opportunities. In particular, we examine the cost side of the picture: what it would take to provide ANS gas energy services to in-state users. This refers primarily to the infrastructure requirements for providing energy services connected with the ANS gasline to various locations throughout the state. While many of these opportunities are important, many were spread throughout remote regions of the state and were of relatively small volumes. In these instances, the infrastructure requirements to serve these areas would be substantial and swamp the benefits of fuel switching.

There are a number of important issues conditioning the supply of natural gas to new usage opportunities throughout the state. These include:

- Relatively small demand volumes spread over remote areas;
- Distance between AHR and community;
- Required new investments to take high pressure and high Btu gas from the AHR pipeline; and
- Climate and environmental considerations.

Despite these challenges, earlier chapters of our analysis did identify a number of concentrated opportunities for increased in-state usage that warrant further investigation. These concentrated opportunities include:

(1) Natural gas usage for residential and commercial customers in the Interior region (Fairbanks);

(2) Power plant fuel switching in the Interior region (Fairbanks);

(3) Gas-fired central station generation with electricity being transmitted to the Interior region (gas-by-wire to Fairbanks); and

(4) Expanded gas usage from the existing LDC system in Southcentral region (Cook Inlet).

In the following subsections, we estimate the cost of supplying these regions/applications with ANS gas. These estimates are preliminary. Our analysis has attempted to use the best available information to estimate the cost of supplying each of these opportunities. As most Alaskans are aware, the costs of developing major infrastructure projects in the state are heavily influenced by geography and climate. Any final conclusions about these infrastructure costs should be subject to a detailed engineering and environmental impact analysis.

9.2: Supplying ANS Gas to the Interior for Residential and Commercial Use

As noted in Chapter 6, there appears to be significant and relatively concentrated opportunities for natural gas usage in the Interior section of the state, primarily in the Fairbanks region. Our earlier analysis identifies close to 2 Bcf of potential residential use, and 2.1 Bcf of commercial use,[1] in this region. In order to supply natural gas to these areas, a number of new infrastructure investments would have to be made. The major infrastructure investments that we modeled included:

(1) Tap and meter station off the AHR pipeline that would reduce gas pressure and remove natural gas liquids for retail quality gas.

(2) Pipeline transportation investments to move the AHR gas from the major pipeline to the city gate.

(3) Distribution system investments including mains and lines to serve the local communities with new gas service.

In addition to the capital investments to supply ANS gas to the region, there are also ongoing administrative and general (A&G) and operation and maintenance (O&M) expenses associated with each of the investments described above. Lastly, commodity cost of gas will also have to be added to the cost of providing service to derive an estimated system average retail rate for serving these new sources of usage.

A number of our gas transportation and distribution assumptions are based upon an earlier conducted study by Stone and Webster (S&W) Engineering. This study examined the natural gas transportation and distribution costs of moving gas from the Cook Inlet to Fairbanks.[2] Meter station/processing costs have come from industry sources. Costs from the earlier S&W study were inflated to 2000 dollars. Transportation costs from the ANS Conditioning plant to the Fairbanks metering station, were based upon an assumed value that encompasses a range of prior studies on this issue.

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[1]This assumes 100 percent commercial penetration.

[2]Stone and Webster Engineering. *Estimated Cost and Environmental Impacts of a Natural Gas Pipeline System Linking Fairbanks with Cook Inlet Area*. Prepared for Alaska Power Authority. Jan. 1989.

Costs for each of the applications we consider in this section were first standardized in order to “price-out” each application. For instance, applications were identified by customers, distance (miles), and volumes. Total transmission costs were estimated from typical transmission costs on a per mile basis, from industry sources.[3] These costs were then multiplied by the mileage in each application. Distribution costs from the S&W study were inflated., and standardized on a per customer basis. The number of customers in each application was then applied to this distribution cost per customer. Capital costs for transmission and distribution were estimated based upon a 10.1 percent allowed return on investment, taxes, and straight-line depreciation for an assumed 30-year life for the assets.

Transmission, meter station, and distribution O&M costs were standardized to a cost per volume figure, and based upon typical gas company costs per Mcf. Volumes utilized by each application were then multiplied by these O&M costs per Mcf to derive total annual O&M costs. Lastly, gas acquisition costs were taken from the 1999 reported value for Enstar.

The next step in our cost analysis was to develop an average rate for each of these unbundled costs (i.e., meter/step down costs, transmission, distribution). Each of the total cost estimates discussed above were divided by total projected volumes to serve as a proxy for an average tariff rate. Our supply analysis of retail gas to the Fairbanks/Interior region is presented in Table 9.1.

[3] We compared our estimated transmission pipeline costs per mile to those published by Oil and Gas Journal in its annual pipeline economics survey. Our estimated costs per mile ($826,000/mile) were well within the range of costs provided for land-based projects, which ranged from a low of $820,000 per mile to a high of $925,000 per mile for 16 inch pipe. See *Oil and Gas Journal*, Pipeline Economics Survey, Volume 99.36: (September 3, 2001), 76

Table 9.1: Estimated System Delivered Cost for Interior (Fairbanks) Region

Fairbanks System Cost per Mcf	
Transportation -- ANS Conditioning Plant to Fairbanks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0307
Levelized Transportation Cost	$0.0307
Levelized Distribution Costs	$1.2538
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$3.9646
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	**$5.8746**

Table 9.1 presents the summary results and the estimated system average retail rate for providing retail gas service to the Fairbanks/Interior region. Our modeled distribution system includes 2.27 Bcf of residential annual gas usage (11,075 customers) and 2.1 Bcf of commercial usage (1,291 customers)[4] under 80 percent penetration of potential regional natural gas load.

Our estimated average retail rates assume that the entire load will shift from its existing fuel source to natural gas. For residential customers, the major fuel switching opportunities include using natural gas for space and water heating. Table 9.2 provides a general examination of the potential savings associated with moving consumption from current fuel sources to natural gas. Annual Btu loads and household expenditures are provided and come from the most recent US Department of Energy Residential Energy Consumption Survey (RECS) for households living in areas with greater than 7,000 heating degree days (HDDs).

[4]Assumes 10,300 square feet per typical commercial establishment from the U.S. Department of Energy, Energy Information Administration, *Commercial Buildings Energy Consumption Survey*.

Table 9.2: Estimated Total Bills for Residential Space and Water Heating by Fuel Type – Interior Region

	Annual Average MMBtu per Household	Natural Gas Cost Per Household	Fuel Oil Cost Per Household	Electricity Cost Per Household	LPG Cost Per Household	Kerosene Cost Per Household
Space Heating	158.01	$928	$1,149	$1,222	$2,245	$738
Water Heating	39.20	$230	$285	$303	$557	$183
Total	197.21	$1,159	$1,434	$1,525	$2,802	$921

Table 9.2 examines the cost of new gas service versus other primary fuels used for space and water heating. Fuel oil is the predominant fuel for residential space and water heating, followed by electricity. There is about a 20 percent discount by moving from fuel oil to natural gas. There is a 27 percent discount by moving from electricity to natural gas for the typical household total bill. Total annual savings would be approximately $275 for households switching from fuel oil to natural gas.

Obviously, there would be conversion costs associated with natural gas furnace and appliance replacement. The rows in Table 9.3 provide various fixed levels of potential investments for furnace and appliance switching. Simple pay backs, based upon estimated annual savings from shifting current primary fuels to natural gas, are presented in each of the columns. As seen in Table 9.3, it would take about 3.6 years to pay off a $1,000 of space and water heating conversions/replacements for customers switching from fuel oil to natural gas.

Table 9.3: Simple Pay-Backs for Fixed Conversion Costs – Interior Region (Number of Years)

Fuel Switching Costs	Natural Gas Vs Fuel Oil	Natural Gas Vs Electricity	Natural Gas Vs LPG	Natural Gas Vs Kerosene
$100	0.4	0.3	0.1	-0.5
$250	0.9	0.7	0.2	-1.3
$500	1.8	1.4	0.3	-2.6
$750	2.7	2.0	0.5	-3.9
$1,000	3.6	2.7	0.6	-5.3
$1,200	4.4	3.3	0.7	-6.3

Our conclusions, based upon this very general cost analysis, are that serving natural gas to these communities may be possible. Some industry sources we consulted during the course of this investigation noted that savings in the 10 to 20 percent range are usually considered important in getting residential and small commercial customers to switch. Our estimated savings, under the reasonable optimistic scenario (i.e., 80 percent penetration rate), are around 20 percent for switching from fuel oil to natural gas and about 24 percent for switching from electricity to natural gas. However, these savings are based upon generalized cost assumptions of serving new areas and should be viewed as such.

9.3: Supplying ANS Gas to the Interior for Power Plant Fuel Switching

As noted in Chapter 8, there are a number of fuel switching opportunities for power plants in the Interior region. From our GIS analysis, we identified close to 200 MWs of power generation capacity that utilizes fuel oil or diesel as a primary fuel. These plants, and their operating characteristics and costs, are presented in Table 9.4. This table identifies each unit, the date it was placed into service, its current age, its prime mover by technology, primary fuel, and heat rate (i.e., amount of Btus required to generation one kWh of electricity.)

Table 9.4: Possible Fuel Switching Interior Power Plants

Utility Name	Plant Name	Unit	Capacity (kW)	Prime Mover	Primary Fuel	In Service Year	Plant Age	Estimated Heat Rate	Average Variable Cost per kWh
Alaska Power Co	Tok	3A	1,320	IC	FO2	1999	2	13,000	$0.0677
Alaska Power Co	Tok	4A	1,135	IC	FO2	1989	12	15,000	$0.0782
Alaska Power Co	Tok	5A	1,140	IC	FO2	1996	5	13,000	$0.0677
Alaska Power Co	Tok	7	1,250	IC	FO2	1984	17	15,000	$0.0782
Alaska Power Co	Tok	8	440	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Tok	9	930	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Dot Lake	1	125	IC	FO2	1990	11	13,000	$0.0677
Alaska Power Co	Chistochina	1	100	IC	FO1	1991	10	13,000	$0.0677
Alaska Power Co	Chistochina	2B	85	IC	FO1	1999	2	13,000	$0.0677
Alaska Power Co	Mentasta	1A	60	IC	FO2	1993	8	13,000	$0.0677
Alaska Power Co	Mentasta	2	100	IC	FO2	1992	9	13,000	$0.0677
Alaska Power Co	Mentasta	3A	90	IC	FO2	1996	5	13,000	$0.0677
Golden Valley Elec Assn Inc	Chena	6	23,100	GT	FO2	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	1	64,700	GT	FO4	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	2	64,700	GT	FO4	1977	24	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	5	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	6	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT1	17,600	GT	FO2	1971	30	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT2	17,600	GT	FO2	1972	29	18,000	$0.0938
Golden Valley Elec Assn Inc	Healy	IC1	2,500	IC	FO2	1967	34	28,500	$0.1485

IC = Internal Combustion

GT = Combustion Turbine

The analysis of power plant fuel switching costs is similar to the preceding analysis of Interior region retail service opportunities. The results have been presented in Table 9.5. First, we estimated the costs of serving these facilities with natural gas. Total transportation costs were developed in a fashion similar to that for the Interior section. Transmission costs were developed on a per mile basis, distribution costs were assumed to incur only half of the capital investment per customer as traditional residential and commercial customers, step-down and meter station costs were also included. Annual transmission and distribution O&M were taken from the estimated utilized earlier.

All costs were then rolled into an overall estimated tariff (average) rate. This rate can be thought of as a delivered rate of gas since it includes the commodity portion of the gas costs in addition to the transportation amount. Commodity gas costs were based upon the 1999 annual gas costs of $1.74 per Mcf. The column entitled "fuel savings" estimates the total cost savings on a per kWh basis associated with shifting fuel from fuel oil to natural gas. For most generating units, the annual average savings ranges from four-tenths to nine-tenths of a cent.

The second cost we examined included the capital expenditures required to convert these facilities to natural gas. These costs range between $2 to $5 per installed kW of capacity. The column entitled "total conversion costs" provides these estimates. These costs were then converted to a per kWh basis and backed out of the gross savings discussed above. The column entitled "net fuel savings" includes the capital expenditures associated with putting in fuel conversion equipment. Total annual average savings range from 0.87 cents per kWh to 0.36 cents per kWh (i.e., less than one cent per kWh).

These savings, multiplied by the average annual generation level for each facility, yields a total annual savings per facility. This is presented in the column entitled "total net savings." Total per facility savings range from a high of $2.8 million per year, to a low of $1,800 per year. However, the savings are based upon estimates that pipeline infrastructure is laid to the region for converting <u>all</u> eligible power applications. Hence, these figures cannot be taken individually per facility. The estimates are on a per facility basis assuming the infrastructure costs are spread across the volumes for eligible applications. Dropping one or two facilities, for instance, would drive up gas transmission and distribution rates, and effect the economics of fuel conversion for the remaining applications.

Table 9.5: Potential Savings from Fuel Switching Power Plants in the Interior Region

Utility Name	Plant Name	Unit	Capacity (kW)	Estimated Heat Rate	Current Fuel Cost ($/kWh)	Gas Fuel Cost ($/kWh)	Gas Transport ($/Mcf)	Gas Fuel Cost with Transport ($/kWh)	Fuel Savings ($/kWh)	Total Conversion Cost	Net Savings ($/kWh)	Total Net Savings
APC	Tok	3A	1,320	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$6,600	$0.00364	$40,019
APC	Tok	4A	1,135	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$5,675	$0.00430	$40,577
APC	Tok	5A	1,140	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$5,700	$0.00364	$34,562
APC	Tok	7	1,250	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$6,250	$0.00430	$44,689
APC	Tok	8	440	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$2,200	$0.00430	$15,730
APC	Tok	9	930	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$4,650	$0.00430	$33,248
APC	Dot Lake	1	125	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$625	$0.00364	$3,790
APC	Chistochina	1	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Chistochina	2B	85	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$425	$0.00364	$2,577
APC	Mentasta	1A	60	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$300	$0.00364	$1,819
APC	Mentasta	2	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Mentasta	3A	90	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$450	$0.00364	$2,729
GVEA	Chena	6	23,100	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$115,500	$0.00528	$1,014,118
GVEA	North Pole	1	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	North Pole	2	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	Fairbanks	5	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	6	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	GT1	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Fairbanks	GT2	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Healy	IC1	2,500	28,500	$0.14849	$0.04959	$3.14355	$0.13918	$0.00930	$12,500	$0.00870	$181,067
Total												$8,875,417

The analysis presented in Table 9.5 is based upon generalized assumptions about plant operating characteristics. In order to determine the outer possibilities for gas usage at these facilities an average operating capacity factor of 95 percent was assumed. This level may be unrealistically high. Table 9.6, however, presents a range of different cost savings and fuel usage at various different average capacity utilization factors.

Table 9.6: Cost Savings from Fuel Switching Under Different Average Capacity Factor Assumptions.

Capacity Factor	Gas Usage (Mcf)	Savings Per kWh Low	Savings Per kWh High	Total Savings
95%	30,284,049	0.00360	0.00870	8,875,417
75%	23,908,460	0.00350	0.00850	6,794,093
50%	15,938,973	0.00310	0.00820	4,192,437
25%	7,969,487	0.02000	0.00700	1,590,781

<u>9.3.1: Gas By Wire Application – Power to the Interior</u>: Another potential new gas usage opportunity that we identified in an earlier chapter of our report was a gas by wire application. This application includes placing a central station power generation facility close to the AHR step-down meter station near Fairbanks (say), then transmitting the electricity (fueled by natural gas) to the Interior region of the state. The advantages of this opportunity include generating electricity with a more efficient, state of the art natural gas fired power generation facility. In addition, some gas distribution costs, which have been the more expensive costs associated with moving ANS gas to local communities, can by avoided.

The disadvantages of the gas by wire application is that, without substantial growth in electricity demand, the addition of new power generation facilities prior to 2014 could displace existing plants. The remaining costs associated with these displaced units would have to be recovered. Since most utilities in Alaska are publicly owned, ratepayers and shareholders are in the same group. Developing creative policies for recovering these costs would be needed.

Our gas by wire application considers the cost of transportation from ANS to the tap location near the AHR pipeline. We also include meter station and tap costs, as well as a small amount of transportation costs (we assume facility is located within one mile). In addition, we examined the cost of moving power from the generation facility, located in close proximity to the AHR, to the Interior region.

We have assumed that a 345 kV power transmission line would be developed to move gas from the power plant to the Interior section. Substation costs at the plant, and at the distribution system, are also included. The results from our analysis are presented in Table 9.7.

Once the costs of transportation (gas and power) are included in the total cost of dispatching new gas fired electricity, the new power application becomes less attractive. The total dispatch cost increases from between 50 percent to almost 100 percent depending upon the fuel cost assumptions examined.

At \$28.41/MWh, the gas-by-wire dispatch costs under the MPL fuel cost assumption is higher than the average gas generation dispatch cost for MPL (\$26.04/MWh, see Table 8.8 in Chapter 8). At \$24.86/MWh, the gas-by-wire dispatch costs under the CEA fuel cost assumption is considerably higher than the average gas-fired CEA generation cost of \$15.60/MWh. However, even at \$36.34/MWh the gas-by-wire dispatch cost is competitive with the average gas fired generation cost of GVEA which is estimated to be \$43.62/MWh.

We would conclude that, given the relatively higher cost in the GVEA region, there may be some potential applications for a gas-by-wire application that moved electricity into the interior. A more detailed study on power and gas transmission costs, however, would be necessary to draw definitive conclusions.

Table 9.7: Gas By Wire Application, Dispatch and Levelized Cost with Power and Gas Transmission

General Plant Cost and Operating Assumptions			
Capacity Factor	95%	Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000	Annual Carrying Cost	$22,414,158
Heat Rate	6,000	Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	$700		
Capacity (kW)	250,000	Deprecation, Years	30
Total Installed Cost	$175,000,000	Rate of Return	10.2%
Capital Cost; $/kW/Yr	$23.33	Taxes	38.7%

New Plant at MPL Gas Cost		New Plant at CEA Gas Cost		New Plant at GVEA Gas Cost	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06
Cost of Gas	$2.92	Cost of Gas	$2.33	Cost of Gas	$4.24
Total Annual Gas Cost	$36,474,010	Total Annual Gas Cost	$29,084,074	Total Annual Gas Cost	$52,967,174
Average Variable Fuel Cost ($/kWh)	$0.01753	Average Variable Fuel Cost ($/kWh)	$0.01398	Average Variable Fuel Cost ($/kWh)	$0.02546
Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500
Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588
Total Dispatch Cost ($/kWh)	$0.02842	Total Dispatch Cost ($/kWh)	$0.02486	Total Dispatch Cost ($/kWh)	$0.03634
Total Levelized Cost ($/kWh)	$0.03919	Total Levelized Cost ($/kWh)	$0.03564	Total Levelized Cost ($/kWh)	$0.04712

9.4: ANS Gas Opportunities in the Southcentral Region

9.4.1: The Natural Gas Supply and Demand Balance in the Cook Inlet Basin: Cook Inlet has been an active oil and gas basin since the discovery of the Swanson River Field in 1957. By the late 1960s nine major oil or gas fields containing nine trillion cubic feet (TCU) of gas had been discovered in the Cook Inlet Basin.[5] Two gas-feed industrial plants and a gas pipeline transmission system linking the Kenai Peninsula to Anchorage were fully operational by 1969.

In June of 1972, the Alaska Oil and Gas Conservation Commission passed a gas conservation order that required gas producers to minimize gas flaring. Over the intervening 25 years, the Cook Inlet Basin was able to deliver gas in quantities equal to or greater than the total usage among all customer classes. The Phillips-Marathon LNG plant and the Unocal Ammonia-Urea plant enjoyed an abundance of inexpensive baseload gas. Their investments in gas production facilities and pipeline infrastructure enhanced deliverability and lowered gas costs for residential and commercial users in Southcentral Alaska. Historic gas consumption by major customer classification is shown for the period 1971 through 2000 in Figure 9.1. Over the past five years, industrial users consumed approximately two-thirds of total gas dispositions. Residential and commercial users account for the other one-third.

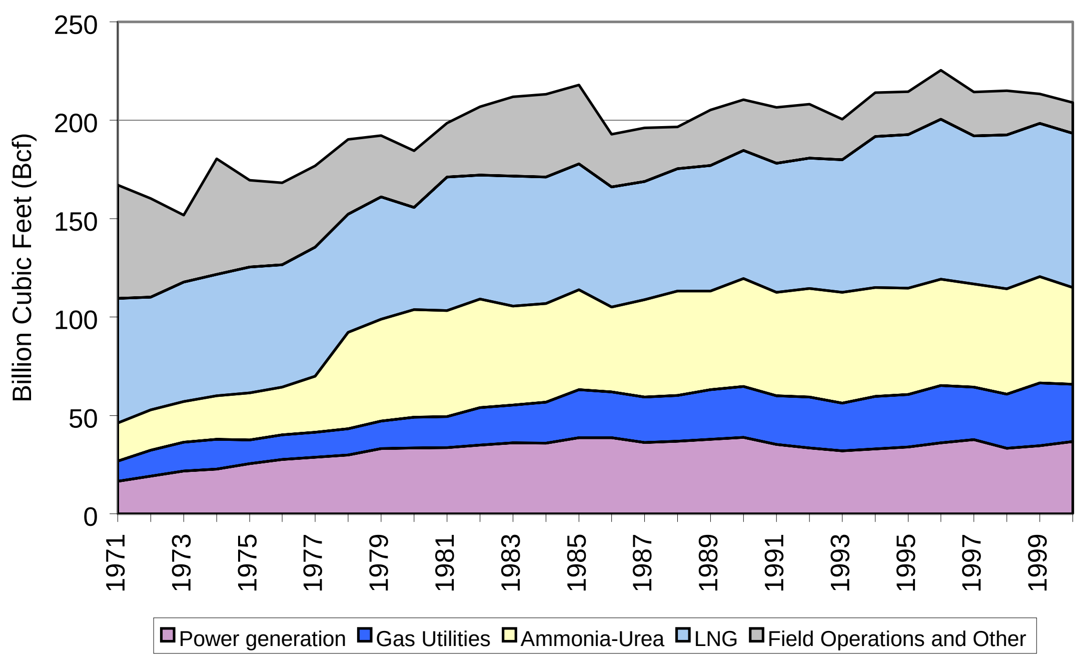

Figure 9.1: Cook Inlet Historic Gas Consumption by Major Disposition Category, 1971-2000

[5] Including Swanson River oil field and the Kenai (2.467 Tcf), North Cook Inlet (2.337 Tcf), McArthur River (1.377 Tcf), and Beluga (1.257 Tcf), plus several smaller gas fields.

December 1996 marked the end of the era of excess gas supply in the Cook Inlet Basin. At that time, Phillips and Marathon filed an application with the U.S. Department of Energy to renew and extend their license to export LNG to Japan. Coincidentally, a deep, winter cold snap in the Southcentral region and a compressor failure on the Steelhead platform resulted in abrupt but short-term gas curtailments to industrial plants. While the reasons and responsibilities for the industrial curtailments were disputed, the event itself signaled a transition to a new era of potential deliverability shortfall under extreme conditions of peak gas demand.[6] In April 1999 the DOE extended the Phillips-Marathon license to export until April 2009 but only after a protracted debate over existing and potential reserves estimates in the basin.[7] Estimates of booked reserves in the Cook Inlet Basin from the Alaska Department of Natural Resources currently stand at about 2.148 Tcf of natural gas.[8]

The debate over the Cook Inlet Basin gas supply and demand balance surfaced again in connection with a gas supply-purchase agreement between Unocal and Enstar, submitted to the Regulatory Commission of Alaska (RCA) in November 2000. The contractual agreement, approved with modifications by the RCA in October 2001, contains several provisions that fueled debate among stakeholders, including competing gas producers and consumer groups.[9]

For example, the agreement stipulates a pricing mechanism that links the wholesale gas price for Unocal deliveries to the daily average price of Henry Hub natural gas futures.[10] Indexing local gas prices to world commodity prices is, in itself not new to the Cook Inlet Basin. Numerous Cook Inlet gas supply agreements are indexed to world oil prices and to spot prices for fertilizer. This Unocal-Enstar pricing mechanism is unique because it is tied directly to a dominant Lower-48 *gas price marker*, the Henry Hub futures price. The pricing mechanism stipulates a three-year moving average for ". . . contract[s] traded

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[6]Gas curtailments were confined to industrial plants and occurred over a period of several days beginning on December 31, 1996. A subsequent legal dispute among gas producers over actions and responsibilities surrounding these curtailments has been settled. Phillips-Marathon and Unocal have gas exchange agreements in place to provide for orderly curtailments to industrial plants in the event that peak system-wide demand exceeds deliverability.

[7]Office of Fossil energy, *Order Extending Authorization to Export Liquified natural Gas From Alaska*, (Washington DC: U.S. Department of Energy, DOE/FE Opinion and Norder No. 1473), April 2, 1999.

[8]DNR, Division of Oil and Gas, *Historic and Projected Oil and Gas Consumption, 2000 Annual Report*, p. 13, 2000.

[9]Regulatory Commission of Alaska, *Order Conditionally Approving TA 117-4 (Gas Sales Agreement) and Requiring Filing*, (Docket No. U-01-7, Order No. 8), October 25, 2001.

[10]Also, it gives Unocal a first right of refusal to supply gas to meet Enstar undesignated supply for up to 450 Bcf. No explicit time limitations were placed on the contract even though RCA's Public Advocacy Staff recommended a nine year contract term. In its final order, the RCA left open the possibility of revisiting the terms of the contract once the 450 Bcf limitation was reached.

during the immediately previous thirty-six month period ended each September 30th of the year prior to the year for which the price is calculated" and a price floor equal to $2.75 per Mcf adjusted for changes in inflation.[11] Unocal is expected to begin making deliveries to the Enstar system under this agreement in 2004.

Figure 9.2 illustrates how the Unocal-Enstar pricing mechanism would work based on *back-casting* a three-year moving average of the monthly Henry Hub spot price during the historic period starting in December 1994.[12] Figure 9.2 compares Unocal-Enstar mechanism with the Alaska Department of Revenue Prevailing Value (DORPV).[13] Several points are noteworthy.

First, the DORPV exhibits an upward trend of approximately seven-tenths of a cent per year over the seven-year historic period. This upward trend is more pronounced after January 2000. Second, the long-term trend for the three year moving average of Henry Hub price is approximately twice that of the DORPV. Third, the 36-month moving average of Henry Hub spot price is on average $0.69 per Mcf higher than the DORPV over the same historic period. This difference becomes more pronounced after September 1998. Fourth, the price floor would have been in effect during much of the historic period, raising gas prices another $0.40 per Mcf, on average. The back-casting results indicate that the Unocal-Enstar price mechanism would have generated higher gas prices than those observed in the recent past in the Cook Inlet Basin.

Figure 9.2 also projects the Henry Hub price and the Unocal-Enstar pricing mechanism based on U.S. Department of Energy, Energy Information Administration forecast of domestic gas prices.[14] Although dispositions under the Unocal-Enstar agreement are not expected to occur until 2004, the pricing provisions in this agreement signal a discrete change in local gas prices at the wholesale level – one that could be interpreted as a response to a prevailing local condition of excess demand for gas. Unocal and Enstar have suggested in testimony to the RCA that higher gas prices are necessary to stimulate exploration.[15]

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[11] *Gas Sales Agreement Between Union Oil Company Of California and Alaska Pipeline Company*, November 2000, p. 21-4. Note, the inflation adjustment is one half of the rate of inflation, measured as the Gross Domestic Product Implicit Price Deflator from the quarter ended June 2001.

[12] Note that the Unocal-Enstar mechanism would adjust once a year, rather than continuously, as reflected in the monthly data in Exhibit 2.

[13] The DORPV is based on a weighted average of gas dispositions to local utilities providing gas and electricity service.

[14] Energy Information Administration. Annual Energy Outlook 2002, Table 14, (Washington DC: U.S. Department of energy), December 2001. Note, the EIA forecast is for average Lower-48 wellhead price. 17 cents per mcf was added to the EIA estimate to approximate the Henry Hub price, based on the historic difference between Henry Hub and EIA estimate for average wellhead price.

[15] *Submittal of Union Oil Company of California's Prefiled Reply Testimony of Daniel B. Thomas, Patrick J. Coughlin and Richard F. Strickland Ph.D,PE.*; *Reply Testimony of Richard F. Barnes*; and *Reply testimony of Daniel M. Dieckgraeff*, Docket No. U-01-007, (July 27, 2001).

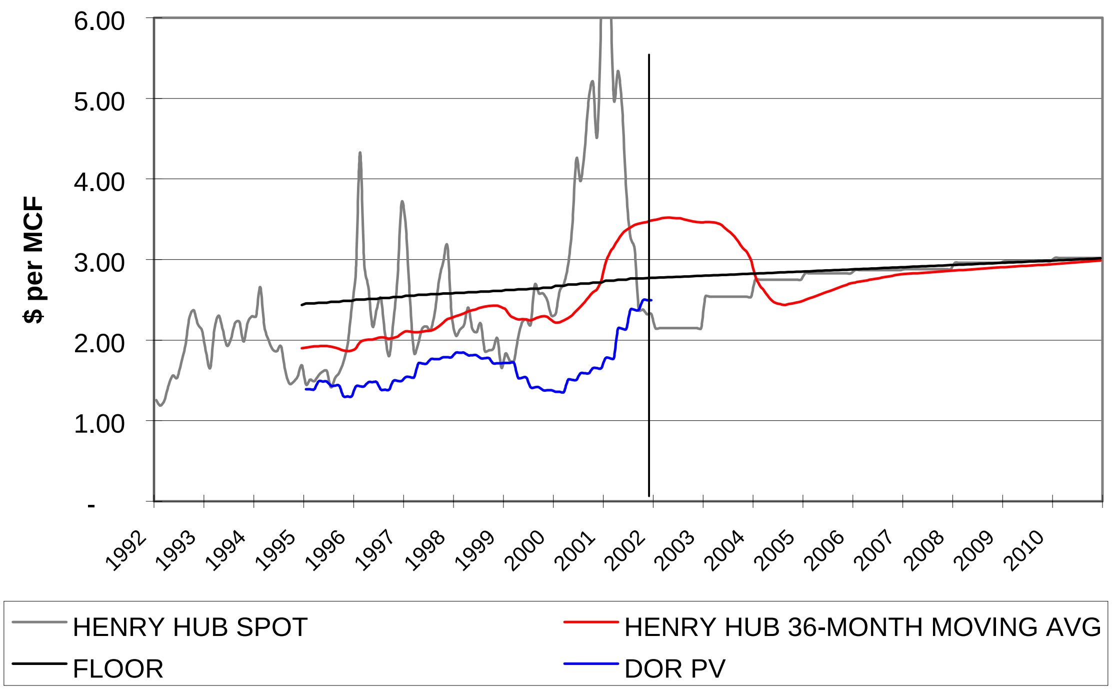

Figure 9.2: Henry Hub 36-Month Moving Average with UNOCAL-ENSTAR Price Floor
Henry Hub Spot Price and DOR Prevailing Value and Backcast: Jan 1992 - Dec 2001 and Forecast: Jan 2002 - 2010

Higher wholesale gas prices have mixed implications. They are expected to stimulate more exploration and lead to new gas discoveries. But also, they raise costs for industrial uses that depend on low-cost gas in order to compete in global markets. While the outcome of expected higher local gas prices is still uncertain, an aggressive program of oil and gas exploration in Cook Inlet was evident in 2001, as shown in Table 9.8. The implications of stepped up exploration for the gas demand-supply balance in the Cook Inlet Basin are illustrated in Figure 9.3 and Figure 9.4.

Assume that relative energy prices remain stable and the demand for Cook Inlet gas, including gas dispositions for LNG Exports, continues to grow at the steady pace outlined in the baseline forecast of Chapter 4. Assume further that production from the existing 2.148 Tcf reserves base continues along reasonable rates of decline for various producing fields. If no new discoveries of gas are forthcoming, then annual deliverability shortfalls can be expected by 2004 or 2005. One Tcf of reserves appreciation would provide a four-to-five year buffer and forestall annual deliverability shortfalls until around 2009.

In addition to one Tcf of added reserves, assume further that the license to export LNG to Japan is not extended beyond April 2009. This situation is illustrated in Figure 9.4. The abrupt fall in demand after 2009 reflects closure of the LNG plant. Here, annual deliverability shortfalls would not occur until after 2015.

These examples suggest that, while gas reserves for utility dispositions are relatively secure, industrial users of Cook Inlet gas have some exposure to the prospect of gas deliverability shortfalls, even when reasonable reserves additions are taken into account. Thus, over the long run, additional gas reserves beyond 1 Tcf will be required to provide continued gas service to industrial users in the Cook Inlet Basin.

Table 9.8: Cook Inlet Oil and Gas Exploration Activity, 2001

Unit or Project	Companies	Description
Ninilchik and Falls Creek	Marathon	G.O. #1 well completed as gas well, G.O. #2 well planned.
Pretty Creek Lewis River Ivan River	Unocal	Re-entered one well each in Lewis River and Ivan River; drilling P.C.U. #4, new well, in Pretty Creek Field.
South Ninilchik and Deep Creek	Unocal	Up to three wells planned on State and CIRI lands in 2001-02.
Swanson River Unit Gas Satellites Project	Unocal	Proposal to develop two gas fields north and east of Swanson River oil field on Federal and Native owned lands.
Redoubt	Forest Oil (discovered in 1968 by Pan Am)	R.U. #1, #2, & #3 wells completed by Forest; R.U. #4 is planned. Up to 193 MMBO recoverable reserves. Forest has other prospects at Sabre, Corsair, and Valkyrie.
Pioneer (Coalbed gas, no proven reserves)	Evergreen Exploration	Formerly operated by Ocean Energy, ownership and operations transferred to Evergreen in mid-2001. Two production wells and one injection well drilled in 1999; Evergreen is committed to drill six more wells, at least one in each of two new areas.
Cosmopolitan	Phillips (discovered in 1967 by Penzoil)	Hansen #1 well permitted to drill to bottom location on State lease.
Nikolai Creek	Aurora Gas	Production started in October; NCU #3 well produces at rate of 2 MMCF per day.
North Fork	Gas Pro	Project apparently on hold.
Trading Bay Unit/McArthur River Field (Oil)	Unocal	T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet.

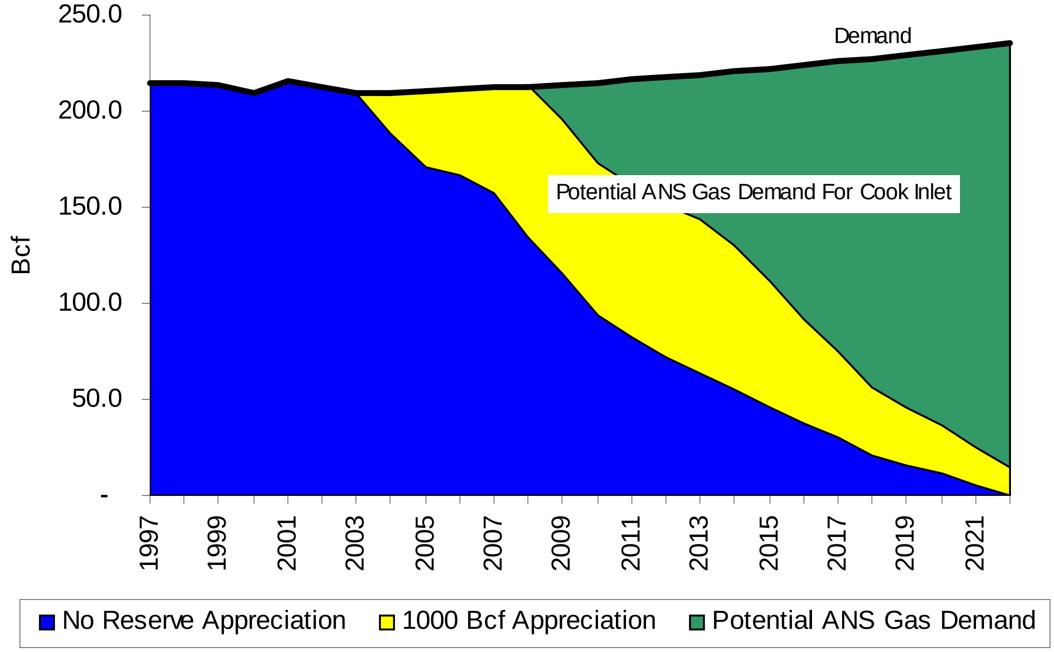

Figure 9.3: Projected Cook Inlet Supply and Demand
Typical Production Scenario with 1 Tcf Reserve Appreciation

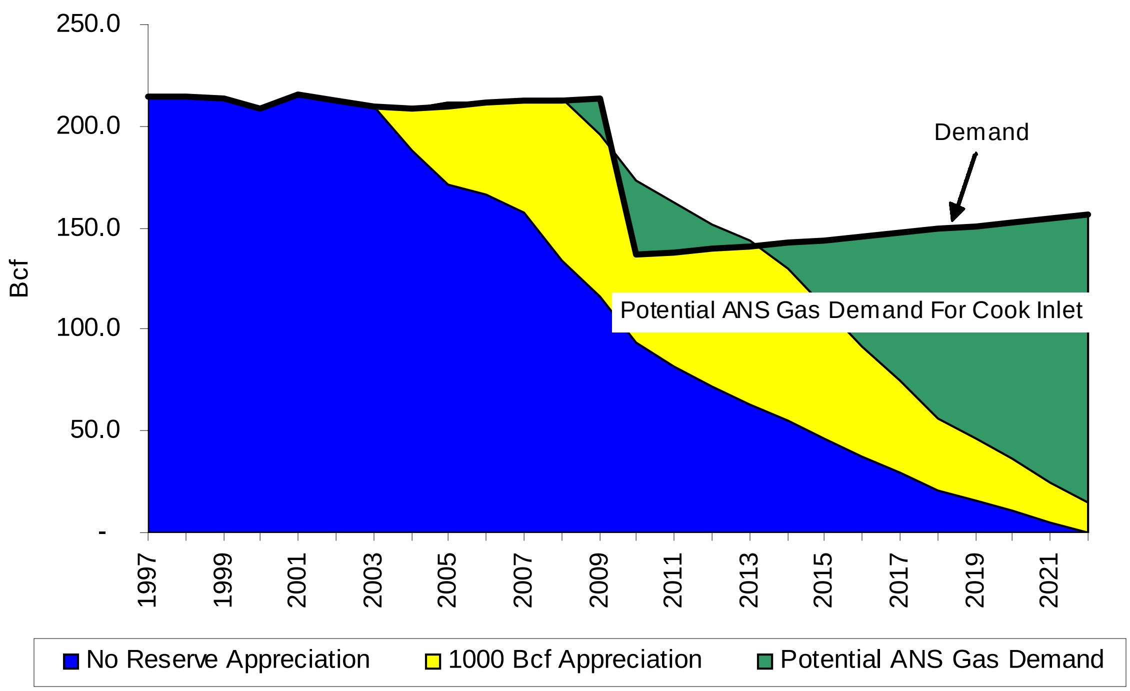

Figure 9.4: Projected Cook Inlet Supply and Demand
LNG Export License Renewal Denied

<u>9.4.2: Retail Opportunities in the Southcentral Region:</u> First, consider the implications for expanded gas usage for the Southcentral region, similar to that for the Interior region. We modeled a standardized system to serve the region's *new* natural gas usage. (We assume existing baseline consumption is supplied from existing sources in the Cook Inlet Basin.) The new system is comprised of 11,219 new remote residential customers and 2.2 Bcf of additional annual natural gas usage.

We examined two different opportunities for transporting the natural gas to the region. Our approach is to assume that a lateral spur pipeline from the AHR pipeline is constructed and considered part of the overall pipeline system for pricing purposes. This could entail some spreading of the costs of the system if a zonal based transportation tariff for the region were developed.[16]

We also modeled a system where the cost of the lateral spur was completely recovered from the Southcentral region and no other costs were spread to other out-of-region customers. The overall system average rates are presented in Table 9.9. If the cost of this spur is not spread across some broader region and are allocated only incremental expansion of new residential customer usage, the per-unit cost of moving ANS gas into the region would be prohibitive.

Table 9.9: Estimated System Average Retail Rate for Southcentral/Cook Inlet Region With Entire Spur Transportation Costs

Cook Inlet System -- Separate Spur System Cost per MCF	
Transportation -- ANS Conditioning Plant to Fbks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0477
Levelized Transportation Cost	$13.2203
Levelized Distribution Costs	$2.3655
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$18.2828
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	**$20.1928**

[16]For example, to serve Interior Region gas-by–wire or expanded Interior Region residential and commercial usage. Our analysis showed that if the realized transportation rate was reduced by about $1.25 per Mcf, average retail rates would be around $7.27 per Mcf.

The analysis presented above, is based on small, incremental gas service applications. As expected, many of the applications, given their limited volumes, either generate small, or negative net benefits. However, if volumes were increased, the large fixed costs associated with gas transportation, would decline on a per-unit basis to levels that may compete with alternative energy sources.

9.4.3: ANS Gas as a Means to Meet a Potential Supply/Demand Imbalance in the Southcentral Region: As noted earlier, one area of potential interest to DNR has been associated with supplying the Southcentral region with gas from the ANS given concerns about the availability of future supplies for the region. The RCA also appears to be concerned with this issue as well. In its recent Order conditionally approving Enstar's Gas Sales Agreement (GSA), the Commission noted:

> Natural gas reserves, while plentiful in the past, are declining. It is predicted that the known natural gas reserves in Cook Inlet will be exhausted by 2012. Exploration for new sources of gas in Cook Inlet has not kept pace with other areas. There is also concern that the older fields in the Cook Inlet will be unable to deliver natural gas at the rates required. The ability to meet peak demand may also be affected by the lack of gas storage facilities. Exploration and development of new natural gas sources takes many years and requires that exploration companies act years before reserves are exhausted by customer demand. [Regulatory Commission of Alaska. Order Number 8, Docket Number U-01-7, at 5.]

Given the preceding analysis of fixed and variables costs for gas step-down, transmission, and distribution, we consider the impact of greater throughput on the per transmission and delivered costs.

Table 9.10 presents estimates of the transportation costs associated with two different spur lines from Fairbanks to the Southcentral region: a 16-inch pipeline and a 20-inch pipeline. Discrete transportation/usage volumes are presented in the left hand column, while estimated levelized rates are presented for each volume level, for each type of pipeline. In order to put these volumes into perspective, the second and third columns of the table relate these volumes to total system, and Southcentral 1999 sales.

Table 9.10: Estimated Levelized Transmission Costs (Fairbanks to Southcentral) Under Different Volume Scenarios

Assumed Volume (Bcf)	Percent of Enstar System */1 (1999 Sales)	Southcentral Sales Estimate/*2 (1999 Sales)	Levelized Transmission Rate */3 ($/Mcf)	Levelized Transmission Rate */4 ($/Mcf)
10	21.9%	4.9%	$ 2.9412	$ 3.6378
20	43.8%	9.8%	$ 1.4706	$ 1.8189
30	65.7%	14.8%	$ 0.9804	$ 1.2126
40	87.6%	19.7%	$ 0.7353	$ 0.9095
50	109.4%	24.6%	$ 0.5882	$ 0.7276
60	131.3%	29.5%	$ 0.4902	$ 0.6063
70	153.2%	34.4%	$ 0.4202	$ 0.5197
80	175.1%	39.4%	$ 0.3676	$ 0.4547
90	197.0%	44.3%	$ 0.3268	$ 0.4042
100	218.9%	49.2%	$ 0.2941	$ 0.3638

**/1 Sales volumes are for retail customers only and do not include volumes that may be direct served.*

**/2 Enstar retail with Urea plant 1999 volumes of 53.9 Bcf, LNG volumes of 77.95 Bcf, and and gas generation volumes of 34.57 Bcf.*

**/3 Assumes 16 inch pipe at a cost of $826,018 per mile at 278 miles*

**/4 Assumes 20 inch pipe at a cost of $1.02 million per mile at 278 miles. 20 Inch pipe assumes a 45 million increase from total estimated cost (for 16 inch pipe) provided in S&W Study inflated to 2001 dollars.*

As seen from the table, in order to get the overall costs down to the $1/Mcf threshold, a 16-inch system would need to have volumes of around 30 Bcf and a 20-inch system would need to move volumes in the order of 40 Bcf per year. The 30 Bcf level is approximately 14.8 percent of estimated Southcentral 1999 sales volumes, while 40 Bcf is approximately 19.7 percent of total regional 1999 sales.

While increasing usage volumes can reduce the unit costs associated with transporting natural gas to the Southcentral region, it will not to lower distribution charges. One opportunity, however, may be to incorporate the higher than average costs associated with serving these new customers into the existing Enstar distribution system costs. In effect, existing Enstar customers would subsidize the excess costs of expanding the current system to include the potential remote areas.

Based upon our estimates, the average non-gas related distribution costs for Enstar are approximately $1.55 per Mcf. This estimate comes from taking the Company's 1999 average retail rate and subtracting the total annual average gas acquisition cost. We estimate that taking the excess cost of the new system and averaging them into the combined distribution system costs and volumes yields a subsidy of approximately 3.8 cents per Mcf. However, we would note, while not large in magnitude, this type of cost-shifting policy would have to be deemed in the public interest, and approved, by the RCA.

Figure 9.5 graphs the various different estimated transportation costs for each modeled system under different volumetric assumptions.

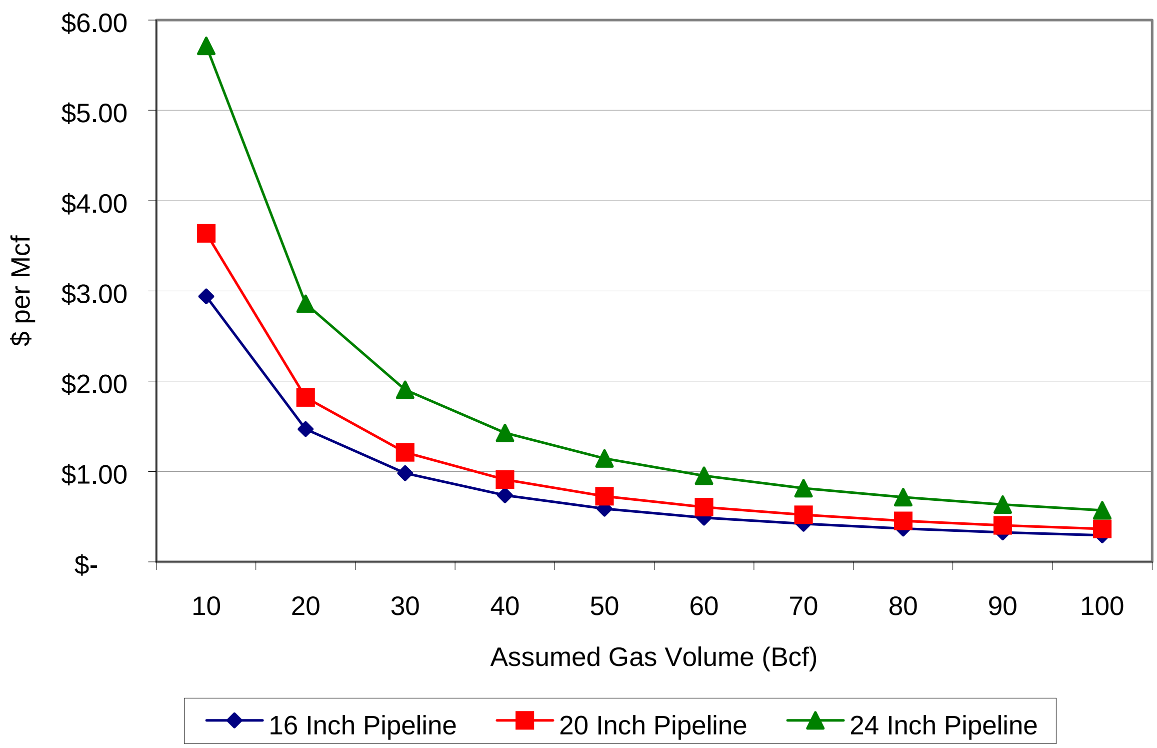

Figure 9.5: Estimate Pipeline Transportation Costs Under Different Volumetric Assumptions

Table 9.11 combines a number of the analyses discussed above for the 16-inch pipeline example. We have estimated total costs associated with providing service into the Southcentral region from a tap located near Fairbanks. Total transmission and distribution costs have been included. Distribution costs, in our example, are from the Enstar system, and include the subsidized portion (i.e., the 3.8 cents per Mcf) of serving the new 2.2 Bcf level of usage associated with remote residential customers. Table 9.11 presents cost estimates for a number of discrete volumes moved over the hypothetical transportation system.

The costs of moving gas, while more economic, are still relatively high relative to 1999 Enstar average rates. However, even with the higher transportation costs, average rates for this hypothetical new system still are below the national average for residential retail customers. The new system yields estimated rates that are between 17 percent to 33 percent below national averages, depending upon the volumes assumed. Even with the pipeline addition, and its increased costs, Alaskans still have the opportunity to pay rates below the national average. Again, we would offer some caution on the numbers. Until detailed engineering studies could be completed, no definitive conclusions can be attained.

Table 9.11: Analysis of Estimated Average Rates – Pipeline System from Fairbanks to Southcentral

Assuming 30 Bcf/y Volumes-- 16 Inch System		Assuming 60 Bcf/y Volumes-- 16 Inch System	
Transportation -- ANS to Meter Station	$ 1.0000	Transportation -- ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.9804	Levelized Transportation Cost	$ 0.4902
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.8044	Total T&D Cost	$ 3.3142
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.7144	Total Delivered Cost	$ 5.2242
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***56.1%***	***Percent Change***	***42.7%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-17.1%***	***Alaska ANS Rate Relative to US Average***	***-28.1%***
Assuming 80 Bcf/y Volumes-- 16 Inch System		**Assuming 100 Bcf/y Volumes-- 16 Inch System**	
Transportation -- ANS to Meter Station	$ 1.0000	Transportation -- ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.3676	Levelized Transportation Cost	$ 0.2941
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.1916	Total T&D Cost	$ 3.1181
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.1016	Total Delivered Cost	$ 5.0281
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***39.4%***	***Percent Change***	***37.4%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-31.1%***	***Alaska ANS Rate Relative to US Average***	***-33.1%***

Our preliminary findings indicate that the levelized cost of a 16-to-20 inch spur pipeline linking Southcentral with the ANS gas pipeline at Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual throughput exceeds 30-to-40 Bcf per year. For example, a 20-inch spur pipeline operating at an average of 40 Bcf per year for 30 years would imply meter-station step-down charges and levelized transmission charges of approximately $1.00 per Mcf (excluding the toll to Fairbanks, as well as local distribution and gas commodity charges). In order to be competitive, the spur pipeline would be required to serve a segment of the existing Southcentral customer base now served by local gas reserves in the Cook Inlet Basin. This result could be favorably influence by scale economies resulting from:

- Sharing spur pipeline transmission charges over a wider customer base along the energy belt;
- Higher rates of penetration than those observed among Southcentral users within the existing ENSTAR system;
- System-wide averaging of distribution charges; and
- Baseline growth in all customer classes including industrial users and expanded gas service.

9.5: Conclusions

When viewed individually, few applications for supplying ANS gas for in-state usage “pencil-out.” Savings from fuel switching are relatively small. There is no substantial need for new power generation until the year 2014. Opportunities for new industry and businesses, like the internet server farm and a new petrochemical facility, are speculative, at best.

One application that warrants further consideration is natural gas delivery into Interior region communities that are in proximity to the proposed AHR pipeline. Our initial results indicate that, on a stand-alone basis, sufficient concentration of residential and commercial space-heating demand exists in the greater Fairbanks area to enable local natural gas distribution to compete with fuel oil and other spacing-heating energy alternatives. When taken in combination with a lateral spur pipeline into Southcentral, the economics of providing gas service to Interior communities for space heating, electric power generation and industrial applications could improve.

Moving gas to the Southcentral region is highly dependent upon future reserve development in the Cook Inlet Basin. Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage – 30 to 40 Bcf per year –

currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The declining rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30 to 40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

The decision of supplying ANS gas to Alaska communities should be left to the market. If reserves fall low enough in currently served regions, prices will have to increase to ration demand.[17] Once prices increase, signals will be sent to the market for the development of either new resources, or new means to bring other resources (i.e., ANS gas) to the region.

Higher prices, while signaling the market about important energy development opportunities, can also serve to send signals to critical, energy-intensive Alaskan industries to move elsewhere. In effect, a cycle is set up whereby higher prices are needed to stimulate infrastructure development, but these prices, in turn, discourage industrial development and retention, which in turn, shift the relative economics of infrastructure development. Reserves and infrastructure development on the supply side typically occur in discrete, lumpy amounts and are often not well balanced with demand. This raises project risk and adds to the challenges faced by resource-development and resource-consuming industries.

[17] The same would hold true for regions that are currently not served with natural gas. If prices for their current energy alternatives increase high enough, then opportunities for moving new energy resources in the region increase.

CHAPTER 10: CONCLUSIONS

The purpose of this report has been to examine opportunities for in-state natural gas usage in Alaska. As noted at the onset of this report, the approach taken to examine these opportunities was based upon the analysis of:

- Existing in-state demand and the development of a forecast to the year 2020.
- Forecast assumptions to determine how in-state demand could shift as a result of changing economic conditions.
- New service opportunities in remote and currently unserved areas of Alaska.
- New potential industries and their impact on in-state gas usage.
- Fuel switching opportunities for oil-fired generators as well as an examination of a central power generation station gas-by-wire application.
- The potential costs of supplying new usage opportunities with natural gas service.

The general findings from the analysis can be summarized as follows.

10.1: Baseline Forecast

Under the baseline forecast, retail natural gas usage is expected to show slow, but consistent, growth through the year 2020. Total usage will grow at an annual average rate of slightly under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. Table 10.1 presents a summary of the baseline usage levels for each major customer class.

Table 10.1: Summary of Baseline Forecast

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,531,308	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Original Source Table: Chapter 4: Tables 4.1, 4.2, 4.3, and 4.4.

10.2: Sensitivity Analysis

Shifts in prices and income can have important impacts on natural gas usage. The impact that shifts in prices can have on usage is relatively more important than income. Under a high price scenario, total in-state annual average growth rates are reduced to about 0.75 percent, while under a low price scenario, annual average growth rates for total in-state usage are increased to 1.05 percent per year. Under a high-income scenario, we anticipate that total in-state usage will increase by an annual average rate of one percent. Under a low-income scenario, total in-state usage will grow by only three-quarters of a percent per year. When compounded over a period of ten-to-twenty years, these impacts could be significant; they range from about 8 to 36 Bcf of incremental gas consumption over baseline levels across all sectors. The sensitivity analysis indicates that gas consumption in 2020 is likely to be between 5 and 20 percent greater than in 2000, depending on future price and income levels. A summary of the various sensitivities has been presented in Table 10.2.

Table 10.2: Summary of Forecast Sensitivities

High Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

10.3: Expanded Service Opportunities

Our analysis also examines the opportunities for expanded service in areas that currently do not have natural gas service. We examined statewide total usage opportunities by region, as well as new service opportunities in areas that are near (within 20 miles) the proposed AHR and existing LDC infrastructure.

After considering a range of expanded service opportunities throughout the state, the largest concentrations of new service opportunities appear to be in the Southcentral and Interior regions. There are also opportunities for increasing natural gas usage within the existing service territories for the Southcentral region LDCs (primarily Enstar). Increasing existing penetration levels by 10 percent results in almost as much expanded usage as moving into new service areas. However, existing average penetration rates of around 80 percent are already high and unlikely to increase under relative prices prevailing today.

A summary of these expanded opportunities is provided in Table 10.3. We have assumed that these service expansion opportunities will be phased in over time with full service opportunities being realized in 2020.[1] Table 10.3 also shows the potential gas demand-supply imbalance in the Cook Inlet Basin. While this does not reflect expanded service, per se, it illustrates the quantity of existing gas usage in Southcentral that may not be met from existing reserves in the Cook Inlet Basin (again, assuming relative energy prices in the future are consistent with levels observed today).

Table 10.3: Summary of Expanded Service Opportunities

Date	Baseline Total (Mcf)	South Central (Mcf)	South Central Imbalance (Mcf)	Interior (Mcf)	New Total (Mcf)
2000	154,980,358	0	0	0	154,980,358
2005	160,395,253	556,182	0	1,078,526	162,029,961
2010	166,836,744	1,112,364	17,914,000	2,157,052	188,020,160
2015	174,587,941	1,668,546	41,325,000	3,235,578	220,817,065
2020	182,232,010	2,224,728	111,161,000	4,314,104	299,931,842

Original Source: Table 6.9

[1] The realization of these service opportunities are assumed to increase cumulatively by about 25 percent each year starting in 2005.

10.4: New Industries

There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of internet server farms and a major petrochemical industry. Both are energy-intensive industries. However, the addition of a typical facility for a large internet facility would have a small impact on total in-state usage. A major petrochemical facility, on the other hand, could have a more meaningful impact. A summary of these new industry opportunities has been presented in Table 10.4. We have assumed that the internet facility opportunities will be realized in full by 2005. The petrochemical opportunities are assumed to be realized after the operation of the proposed AHR gasline is completed and enter the forecast in 2010.

Two urea plant usage opportunities are presented. The first assumes a relatively constant utilization at the existing facility but at levels that are near previous historic peaks (about 7.2 Bcf above 2000 levels). The second provides the usage levels from a potential plant expansion discussed in Chapter 7.

Two estimates for LNG usage are also presented. The first estimate presents relatively constant levels of gas usage. The second estimate reflects the outer range of potential gas usage that was discussed in Chapter 7 (i.e., about 2.8 Bcf per year of additional gas consumption).

Table 10.4: Summary of New Industry Opportunities

Date	Baseline Total (Mcf)	Internet Server (Mcf)	Petrochemical Facility (Mcf)	Ammonia Urea Incremental (Mcf)	Ammonia Urea Expanded (Mcf)	Existing LNG (Mcf)	Incremental LNG (Mcf)	New Total (Mcf)
2000	154,980,358	0	0	7,224,195	0	78,533,532	0	240,738,084
2005	160,395,253	4,355,910	0	7,224,195	0	78,533,532	0	250,508,890
2010	166,836,744	4,355,910	27,853,333	7,224,195	15,000,000	78,533,532	2,873,468	302,677,181
2015	174,587,941	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	325,428,379
2020	182,232,010	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	333,072,448

Original Source: Table 7.1, 7.3

10.5: Fuel Switching

We examined all generating units in the state to identify facilities that could potentially shift their primary fuels to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior region of the state. There is approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Fuel switching opportunities would comprise a considerable source of new gas consumption. The reason for this is twofold. First, in total, the 200 MWs of capacity is of a relatively meaningful size. Second, many of these facilities are older, with heat rates that are greater (i.e., less efficient) than many new technologies. Hence, a greater amount of gas usage per every kWh generated. A summary of these fuel switching opportunities has been provided in Table 10.5. The table assumes that these fuel switching opportunities will not be realized until the proposed gasline is in operation.

Table 10.5: Summary of Fuel Switching Opportunities

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	15,938,973	182,775,717
2015	174,587,941	15,938,973	190,526,914
2020	182,232,010	15,938,973	198,170,983

Original Source: Table 8.4 and Table 9.6

10.6: Gas by Wire

There is a considerable supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the dispatch costs of existing generating units. However, the state does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. The displacement of this older generation could result in stranded costs that would have to be recovered. The public ownership of these facilities raises important questions about potential cost recovery since the traditional separation between ratepayers and shareholders does not exist. Given the higher efficiency of a new power station, gas usage associated with this power generation facility would be considerable but less than fuel switching at existing power facilities discuss above.

A summary of the gas-by-wire gas usage has been presented in Table 10.6. In this table, natural gas usage from new power generation is not expected to increase until 2015, given that Alaska will probably not have need for a new generation facility until the prior year.

Table 10.6: Summary of Gas by Wire Application

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	0	166,836,744
2015	174,587,941	12,483,000	187,070,941
2020	182,232,010	12,483,000	194,715,010

Original Source: Table 8.7

10.7: Supplying Gas to New Usage Opportunities

Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. These investments include taps and meter stations to the main AHR gas pipeline, transportation capital costs for pipelines to the city gate, and capital costs to lay distribution mains and service connections.

We examined a number of major concentrations of potential gas usage, and modeled the typical costs of supplying natural gas to these potential applications. These results included:

> ***New Service to the Interior:*** Positive opportunities for natural gas service from initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent.
>
> ***Gas by Wire:*** There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014.
>
> ***Expanded Service to the Southcentral:*** Study results indicate that, in order to be competitive, throughput on a lateral spur line connecting Southcentral must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in

this study. Some portion of gas usage -- 30-to-40 Bcf per year – currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

Fuel Switching: Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated.

10.8: Summary of Baseline Forecast, Potential New Usage Opportunities, and Total In-State Demand

Based upon our analysis, there are some 107 Bcf of new usage opportunities in Alaska by the year 2020. This represents about 41 percent of baseline forecast in-state use in 2020.[2] Figure 10.1 presents each of these opportunities relative to the baseline forecast, while Figure 10.2 presents a pie chart breaking out the relative contribution each application has to total new usage opportunities.

This estimate is based on the assumption that all of the new usage opportunities are developed: Southcentral residential usage; Interior retail usage; internet facility development, petrochemical facility development; fuel switching opportunities; high utilization LNG and urea plant use; urea plant expansions; and gas by wire application. As noted in Chapter 9, the economics of supplying natural gas to many of these opportunities on an individual basis will not be competitive. The best opportunities for attaining these new usage levels may be from bundling a number of applications.

[2]Baseline includes existing LNG usage. New usage opportunities represent 58 percent of non-LNG baseline (i.e., residential, commercial, industrial, and electric utility).

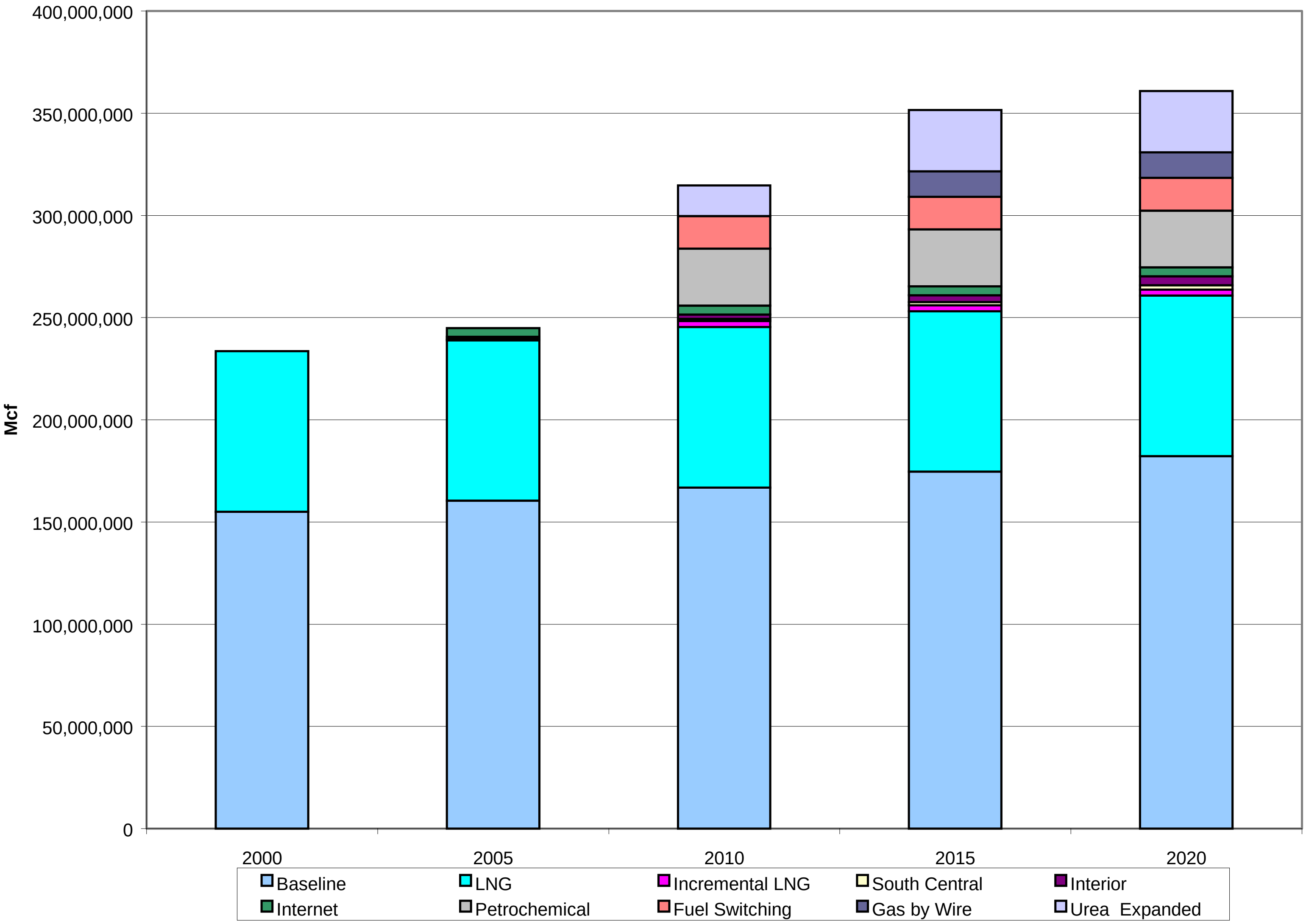

Figure 10.1: Summary of Baseline Forecast and New Usage Opportunities

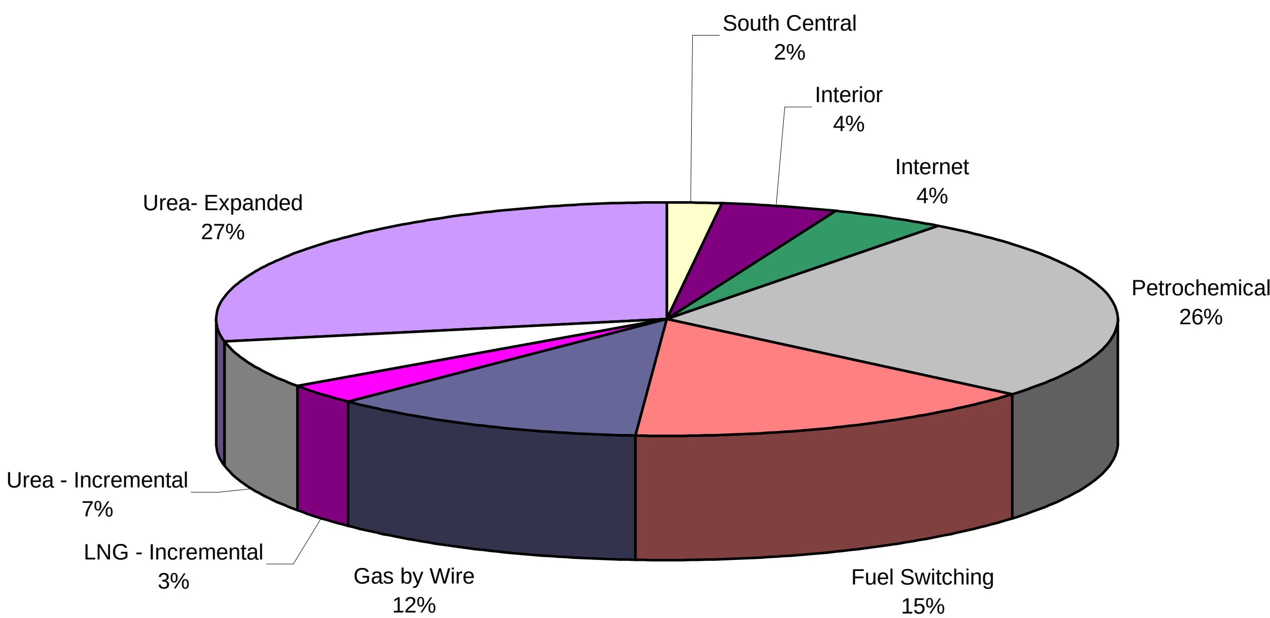

Figure 10.2: Percent Contributions, by Application, for New Usage Opportunities by 2020

As noted in Chapter 9, one of the largest potential concentrations of usage for ANS gas could be in the Southcentral region of the state. Realizing these usage levels, however, will be a function of future natural gas resource additions in the region. If these fail to materialize, then a substantial portion of Southcentral usage could be met with gas supplies from the North Slope. In order for these supplies to come close to being economical, volumes of some 30 to 40 Bcf will have to be served from outside the region. Figure 10.3 shows how potential Southcentral usage, resulting from a regional supply short-fall, would compare to all the other new applications discussed in this report.

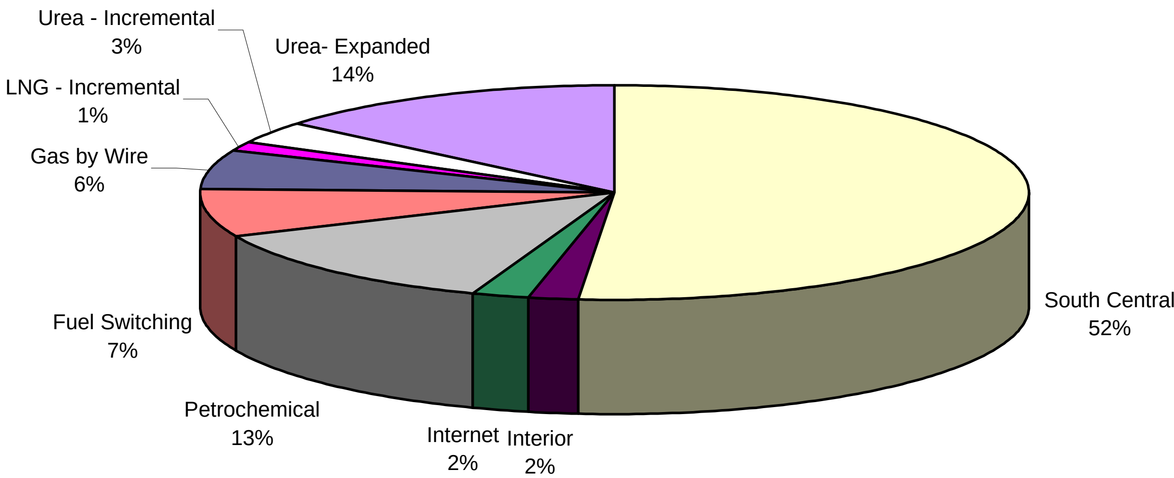

Figure 10.3: Southcentral Usage Relative to New Service Opportunities in 2020

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Volume 2: Technical Appendices

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Introduction to the Technical Appendices

Volume 2 includes three technical appendices associated with this project. All three of these technical appendices have been offered to the reader interested in a more detailed understanding of the analyses conducted during the course of this project. In many ways, these technical appendices have been provided as more lengthy substitutes for the abbreviate discussions included in the main body of the report.

Appendix 1, provides a detailed overview of historic natural gas price and usage trends in Alaska. The appendix covers a much longer time period than the information provided in Chapter 2.

Appendix 2 provides a detailed overview of the natural gas supply and demand modeling literature. This discussion includes some of the observations on empirical modeling that were included in Chapter 3. In addition, some discussion on individual pieces of the academic literature have been outlined in this appendix.

Appendix 3 provides a more detailed discussion of the natural gas demand models that form the basis for the baseline forecast, as well as the forecast sensitivities. The empirical results of the models have been presented, in addition to a host of other statistics associated with the estimated price and income elasticities of demand.

APPENDIX 1
DETAILED HISTORIC OVERVIEW OF ALASKA NATURAL GAS MARKETS

This technical appendix examines past long run historical trends in Alaska's natural gas markets. The trends examined here are for a duration (1970-1999) longer than the analysis included in Chapter 2, which addresses the period 1990-1999. This appendix examines long run trends in natural gas prices and usage for major customer classes in Alaska including residential, commercial, industrial, and electric utility.[1]

A.1.1: Data Used in the Analysis of Alaska Natural Gas Usage

The following discussion, as well as the models that we will develop in subsequent chapters, utilizes data from the EIA 176 database published by the U.S. Department of Energy, Energy Information Administration (EIA). This database is developed and maintained from annual survey information collected by the EIA under EIA Form 176. All major interstate natural gas pipeline companies, intrastate natural gas pipeline companies, investor and municipally owned natural gas distributors, underground natural gas storage operators, synthetic natural gas plant operators, among other providers of natural gas service, are required to complete this form. The completion of this report is mandatory under the Federal Energy Administration Act of 1974.

For a typical LDC, the EIA Form 176 requirements include annual reporting on the disposition of all gas flows over the company's system. This includes accounting for all gas sales, prices (average revenues), and customers for residential, commercial, industrial, and any other retail customer class. In addition, LDCs must report any transportation services (and volumes) for non-core customers. Thus, if a commercial or industrial customer is within the city gate, but receives gas from a third party, the LDC is required to report the volumes it transports to these customers even though the LDC is only providing transportation services.

In the information reported for Alaska natural gas companies, two LDCs filed information on sales, customers, and transportation volumes. The majority of their disposition was associated with traditional retail sales (i.e., residential, commercial, industrial, etc.). However, starting in 1992, Enstar began reporting transportation volumes for one industrial customer.[2] In 1995, the Company began reporting transportation volumes for commercial customers as well. Since

[1]The transportation sector has been excluded since total usage is small, and for many years, information is simply missing.

[2]In such a situation, if an LDC is transporting gas on behalf of a customer within the city gate, then that customer is being served by a competitive third party, presumable a competitive retail natural gas marketer. Thus, identifying transportation customers within an LDC's service can give some indication of the degree of competition within that particular area.

1995, the number of non-core commercial customers for Enstar has grown significantly. In 1995, there were 62 commercial customers receiving transportation service only from Enstar. This increased to 187 in 1996; 401 in 1997; and 768 in 1998. By 1999, this number has grown to 883 commercial customers taking only transportation service.

Other companies with pipeline assets are also required to report transportation and sales volumes even if they are not an LDC. According to the data included in the EIA 176 database, there were 6 non-LDCs reporting either transportation and/or direct sales. These included Arco Alaska, Inc., Chevron USA, Marathon Oil Company, Phillips Alaska Natural Gas Company, Ukpeaqvik Artic Slope, and Union Oil Company of California (UNOCAL). In 1999, these companies, collectively, served 11 commercial customers, of which 2 were transportation customers alone. In the same year, these companies collectively served 9 industrial customers. Enstar provided transportation service to three industrial customers.

The EIA database that we used in our historic trends analysis, as well as in the development of our forecasting models, excludes information from other natural gas uses that are reported separately to the DOE. These include field uses of natural gas in oil and gas production, internal company use of natural gas, pumping and compressor station use of natural gas, and liquefied natural gas (LNG). None of these gas usage activities are included in the commercial and industrial series analyzed in this chapter, nor were these natural gas uses included in commercial or industrial forecasting models. Gas Dispositions to the Kenai LNG Plant are excluded from the EIA data series because the LNG it is exported and not considered as an in-state requirement. However, the role of LNG in Southcentral Alaska is important since it accounts for close to 36 percent of total gas dispositions in the Cook Inlet area (see discussion in Chapters 7 and 9).

In addition to usage and price information included in the EIA Form 176, we compiled additional information to supplement the data we would use to specify our demand equation. This includes energy price information for alternative fuels such as diesel, fuel oil, and electricity. This information was also collected from the US Department of Energy, and is published every year in the Annual Energy Report. We also collected employment and state gross product information from the US Department of Commerce, Bureau of Economic Analysis (BEA).

A.1.2: Historic Natural Gas Retail Price Trends

Historic trends in Alaska natural gas prices are presented in Figure A.1.1. These price trends are in nominal dollars (i.e., unadjusted for inflation) and broken out for each major customer class. Retail prices that are presented in Figure A.1.1 are an approximation. The true definition for the series is average revenues, which are calculated as total revenues divided by total usage. Average revenues are typically used in industry analysis since they reflect, on average, what is paid for natural gas service.

However, rates can be complicated and may not exactly reflect the values that appear in a simple examination of average revenues. For instance, rates are typically charged in the form of a two-part tariff: a fixed customer charge, in addition to an incremental volumetric rate. Further, rates can be complicated by increasing and decreasing block rates, minimum or base usage charges, as well as other complicated riders and surcharges. Nevertheless, average revenues, as a general approximation, do reflect the general tendencies in prices that customers pay over time.

Residential rates over the past 30 years reveal three distinct trends. From 1970 to 1982, residential rates were relatively constant, increasingly at an average annual rate of only 1.5 percent. However, beginning in 1983, rates began a dramatic increase. From 1982 until 1991, residential rates increased at an annual average rate of 10.1 percent. From 1991 until 1999, residential retail rates have started to decline at an average annual rate of 1.5 percent. Rates in 1999 are almost identical to their 1989 level in nominal dollars.

Commercial natural gas rates have followed trends similar to those of residential customers. Shifts in these trends, however, tend to be accelerated by about two years relative to the historic experiences seen for the residential class. For instance, rates for commercial customers were relatively flat throughout the 1970s. However in 1980, rates began to move in a sharp upward trend. This trend was not reflected in residential rates until 1982.

During the period 1980 until 1991, commercial rates increased at an annual average rate of 9.4 percent. This rate of growth was more significant than that experienced by residential customers. During the period 1991 until 1999, this upward trend in rates was reversed, and commercial rates fell at an average annual rate of 1.8 percent. This decrease was much faster than that associated with residential customers.

Industrial rates during the historic period followed different trends than those experienced for residential and commercial customers. For instance, during the period 1970 to 1979, rates for industrial customer followed a relatively steady increase of 11.2 percent on an annual average basis. Between 1979 until 1981, rates fell for industrial customers by 34.5 percent. After 1981, rates increased at an annual average rate of 9.8 percent. In the two most recent years (1997-1999), natural gas rates for commercial customers have been falling.

As seen in Figure A.1.1 natural gas rates charged to electric utilities, to run their natural gas generation, followed somewhat similar trends to those experienced by industrial customers. From 1970 until 1979, rates charged to electric utilities increased at an annual average rate of about 10.3 percent. Like industrial customers, these rates fell, but less drastically during the 1979-1980 period. The drop in rates during this year was nearly 45 percent. However, rates began to rise steadily at an annual average of 14 percent from 1980 until 1990, only to drop nearly 67 percent in 1999.

During the period of 1991-1998 electric utilities experienced a significant percentage increase that averaged 21.1 annually. By 1999, electric utilities saw an 11.7 percent decline in their natural gas rates.

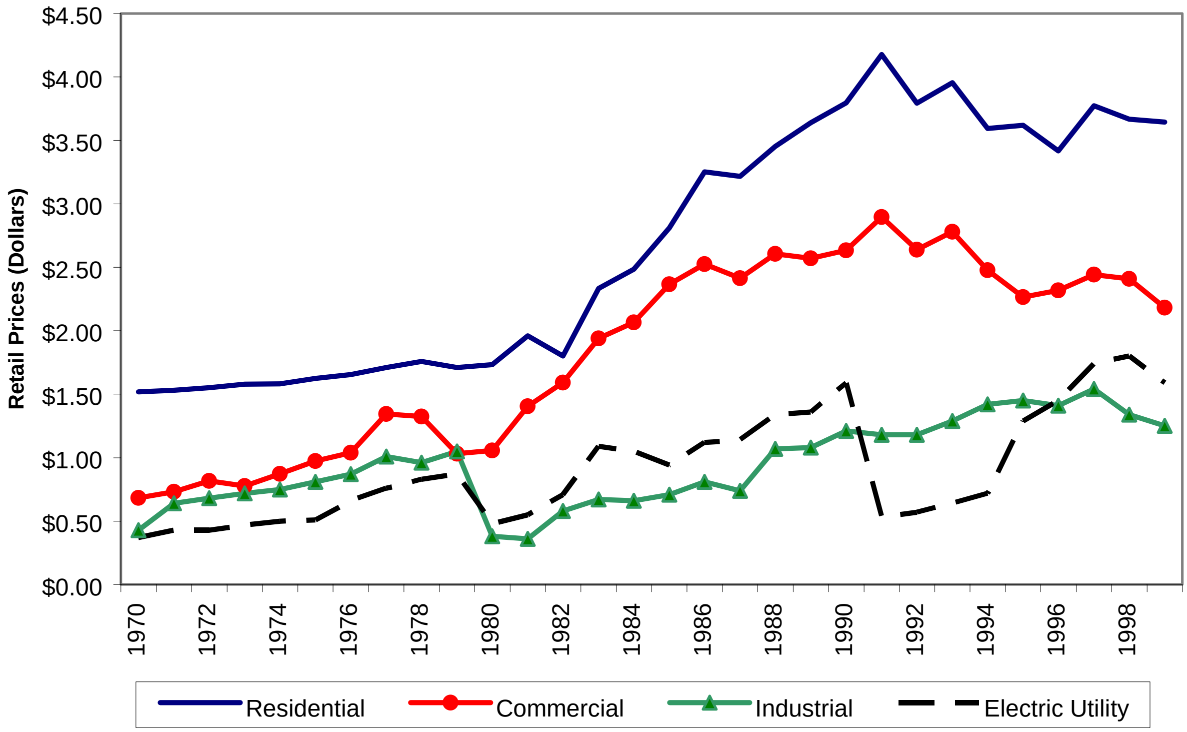

Figure A.1.1: Alaska Retail Natural Gas Prices 1970-1999 (Nominal Dollars)

Source: US Department of Energy, Natural Gas Annual

Figure A.1.2 presents a different representation of natural gas price changes. In this figure, we have plotted price changes in constant, as opposed to nominal dollars. In order to estimate these constant dollar prices, we multiplied the GDP deflator by the nominal prices presented in Figure 2.1. The result defines prices of natural gas in terms of their 1999 value.

In constant dollar terms, natural gas prices for residential customers actually fell throughout the 1970s. Constant dollar prices for residential customers bottomed out in 1982 at $2.85 per Mcf. Constant dollar prices began an upward trek beginning in 1983 for residential customers, and peaked at a rate of $4.88 per Mcf in 1991. Since 1991, natural gas prices, in constant 1999 dollars, have decreased at an average rate of 3.4 percent annually. In 1999, constant dollar natural gas rates for residential customers was $3.65 per Mcf – an amount not seen since 1984.

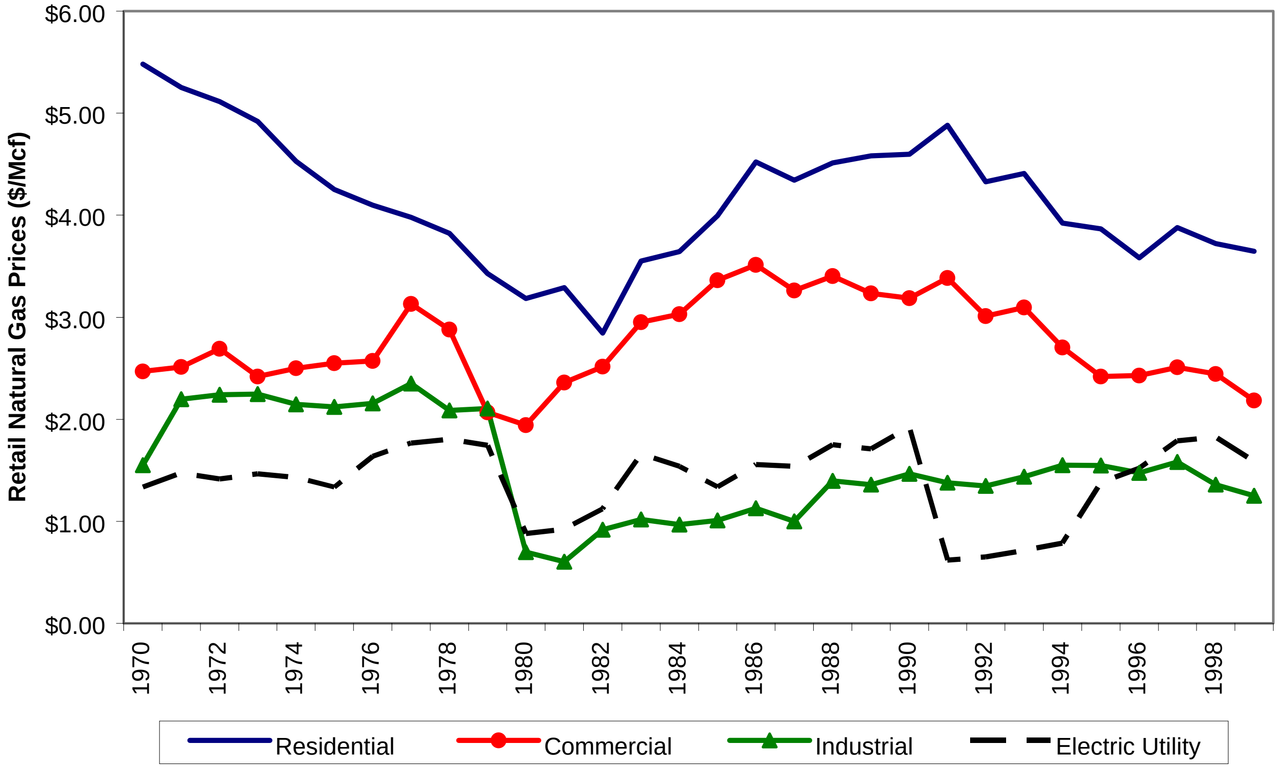

Figure A.1.2: Alaska Retail Natural Gas Prices 1970-1999 (1999 Dollars)

Source: US Department of Energy, Natural Gas Annual.

Constant dollar natural gas rates for commercial customers have followed similar trends to those of residential; there are, however, a few notable exceptions. During the period 1976-1977, commercial customers saw their rates leap by 21.7 percent, during a period in which residential customers saw their rates decrease. Constant dollar rates for commercial customers, while falling from 1978-1980, saw a sustained increase starting in 1981.

During the period 1981-1991, commercial customers saw their rates generally increasing, similar to residential customers. However, the rate of this increase was much greater for commercial customers. During the peak of this run up in prices (1981-1985), constant dollar commercial rates increased by 42.5 percent compared to a 21.3 percent increase during the same period for residential customers. Since 1991, constant dollar rates for commercial customers have been falling. In 1999, constant dollar commercial natural gas rates, were $2.18 per Mcf – a rate approaching the all time low constant dollar price of $1.94 per Mcf 1980.

Constant dollar prices for industrial customers and electric utilities have followed patterns similar to each other, but under trends which differ in various years from residential and commercial customers. Relative to historic trends, constant dollar industrial rates were high during the period 1970 to 1980. For instance, the average retail rate for industrial customers during this period was some 159.2 percent of today's rates in constant dollars. The opposite is true for electric utilities which saw the relative average level for the period somewhat lower, at 93.2 percent of current rates in constant dollars.

From 1980 to 1990, constant dollar rates increased by 142.3 percent and 108.4 percent for industrial and electric utilities, respectively. From 1990 onwards, industrial rates decreased by an annual average of 1.5 percent. Electric utility rates, however, saw a sharp decrease from 1990-1993, followed by a steady increase through 1998. In 1999, industrial rates, in constant dollars, are at levels that are lower to their 1970 level while electric utility rates are slightly higher than 1970 rates.

A.1.3: Historic Total Natural Gas Usage Trends

Figure A.1.3 presents historic trends in Alaska natural gas usage between 1970 to 1999. The figure shows significant growth for in-state natural gas usage from 1970 until 1979. However, after 1979, annual changes in natural gas usage follow a rather saw-toothed trend. On average, the period 1979-1999 has seen relatively stable and low natural gas usage growth with the biggest variations in total usage coming from the state's industrial customers. Since 1982, total sales varied between approximately 130,000 and 150,000 Mcf per year.

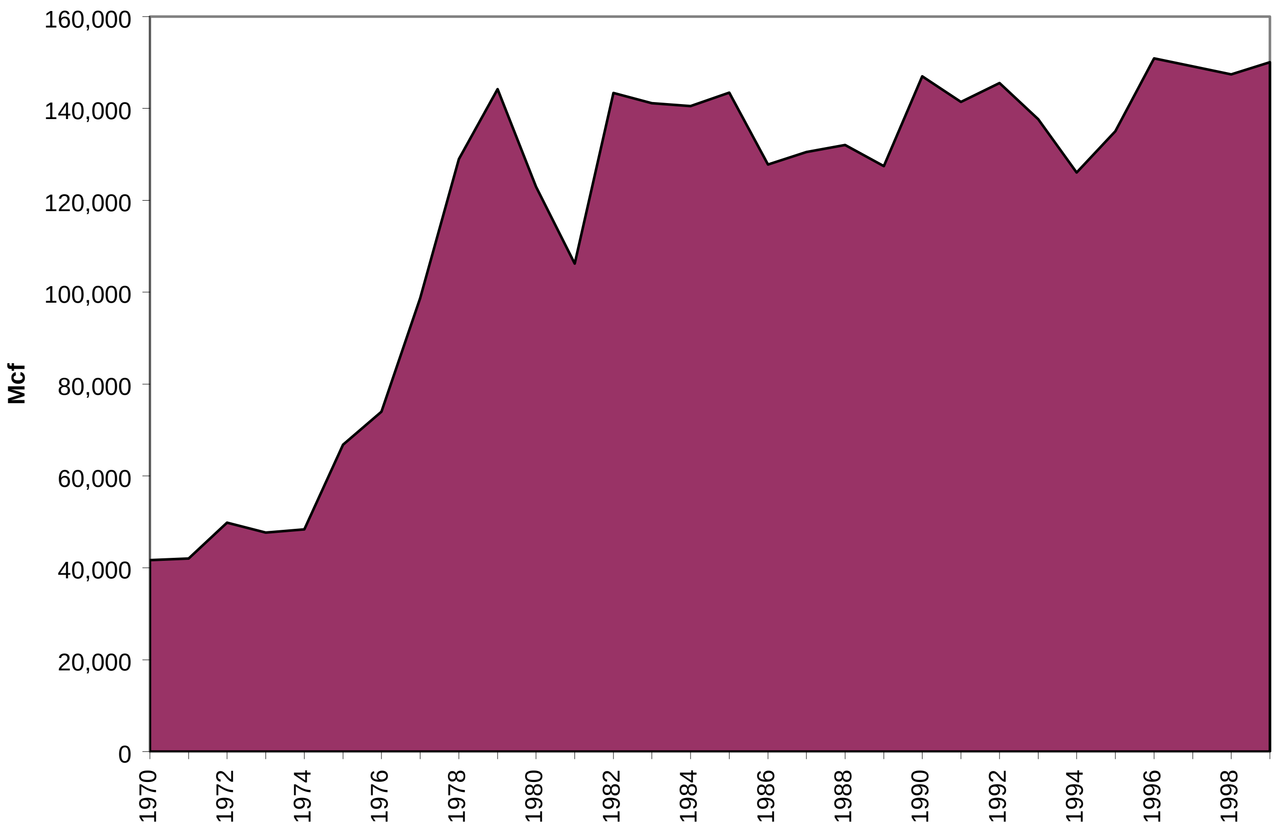

Figure A.1.3: Alaska Total Natural Gas Usage (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

Figure A.1.4 decomposes natural gas usage into its respective customer classes. As the figure reveals, the residential, commercial, and electric utility classes all show a somewhat slow and steady growth path over the past thirty years. There are some periods that show large amounts of growth in volume, such as residential growth of nearly 150 percent between 1974 to 1975, but average growth over the period in all three categories has slightly outpaced customer growth.

As noted before, the industrial class accounts for the majority of the variation in Alaska natural gas usage. There is a substantial increase in industrial natural gas usage during the late 1970s of over 550 percent. This rise is immediately followed by a decline of approximately 43 percent in the following two years. Sales to industrial customers over the past several years have hovered between the extremes set in 1979 and 1981, respectively. In 1999, industrial natural gas usage was approximately equal to its level in 1977. Commercial and residential usage are 184 percent and 121 percent higher than their respective levels in 1970.

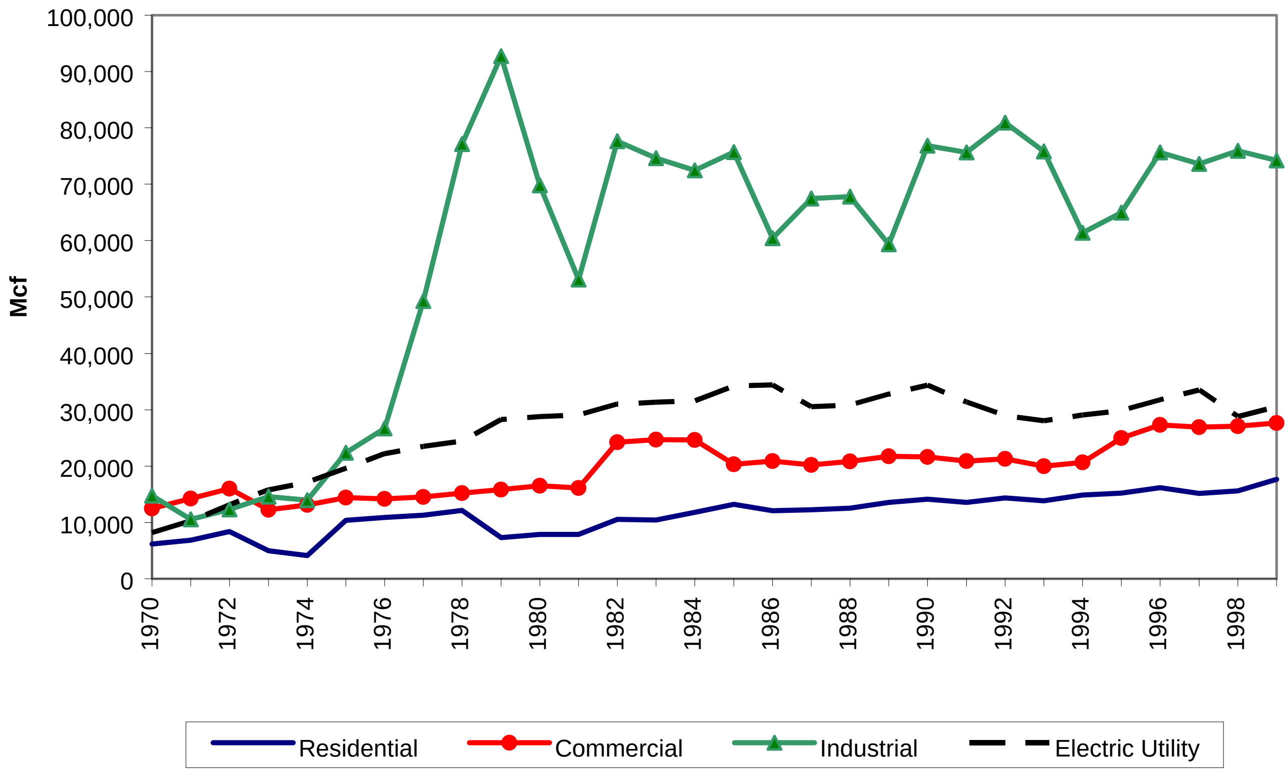

Figure A.1.4: Natural Gas Usage by Major Customer Class (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual.

A.1.4: Historic Residential Natural Gas Usage Trends

Figure A.1.5 analyzes residential customer and usage growth during the period 1970 to 1999. The left hand axis measures the number of total residential customers, while the right hand axis measures total residential usage. There are two large discontinuities in the usage trend occurring in the early and late 1970s. These leaps are associated with the energy crises and the tendency to shift consumption away from oil and towards more natural gas usage. After 1980, however, we see relatively stable trends in residential customer and usage growth. Between 1981 and 1983, residential customer growth leaped by 37.5 percent.

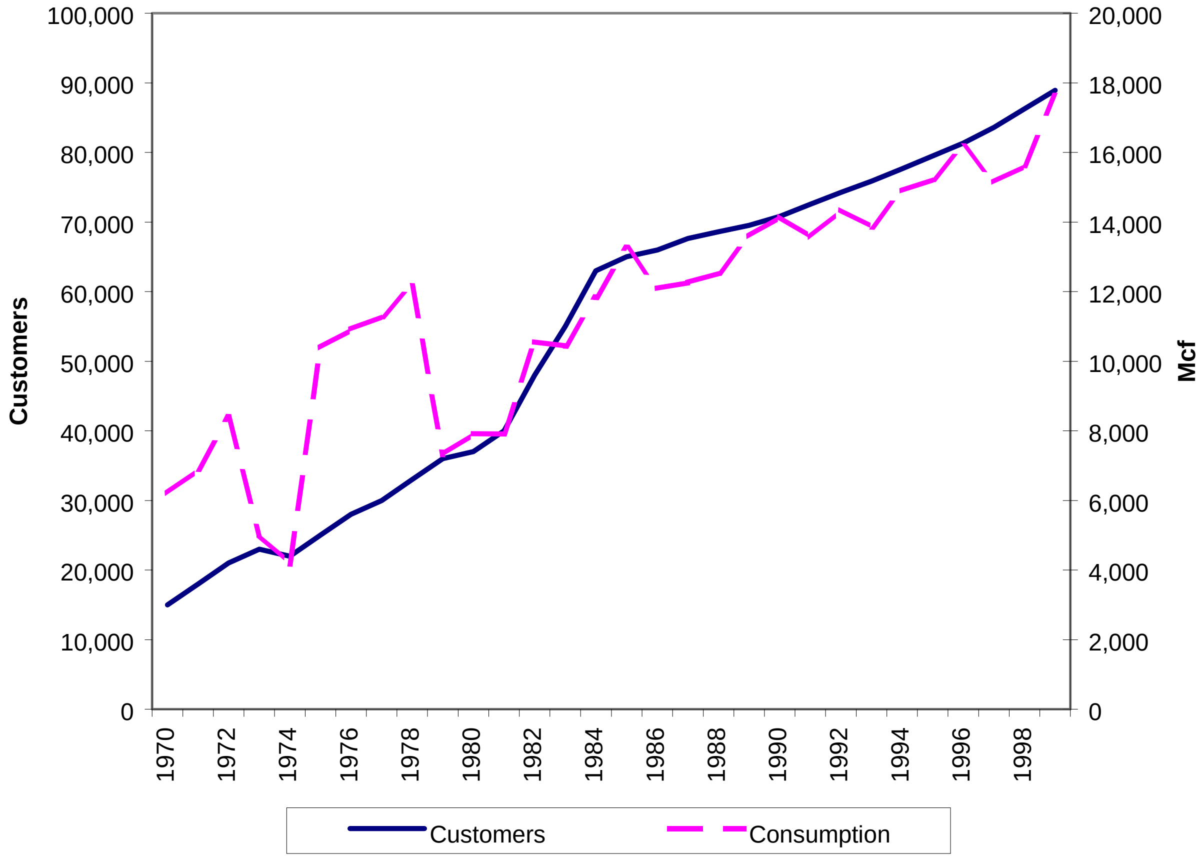

Figure A.1.5: Alaska Residential Customers and Usage (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

Figure A.1.6 presents the historic evolution of residential usage per customer and price. Residential average usage followed a number of erratic leaps during the early and late 1970s. After 1979, usage per customer followed a relatively stable trend. Between 1982 and 1991, residential natural gas prices increased by an annual average of 10.1 percent. Average usage during this period, remained relatively flat falling by about 1.5 percent on an annual average basis.

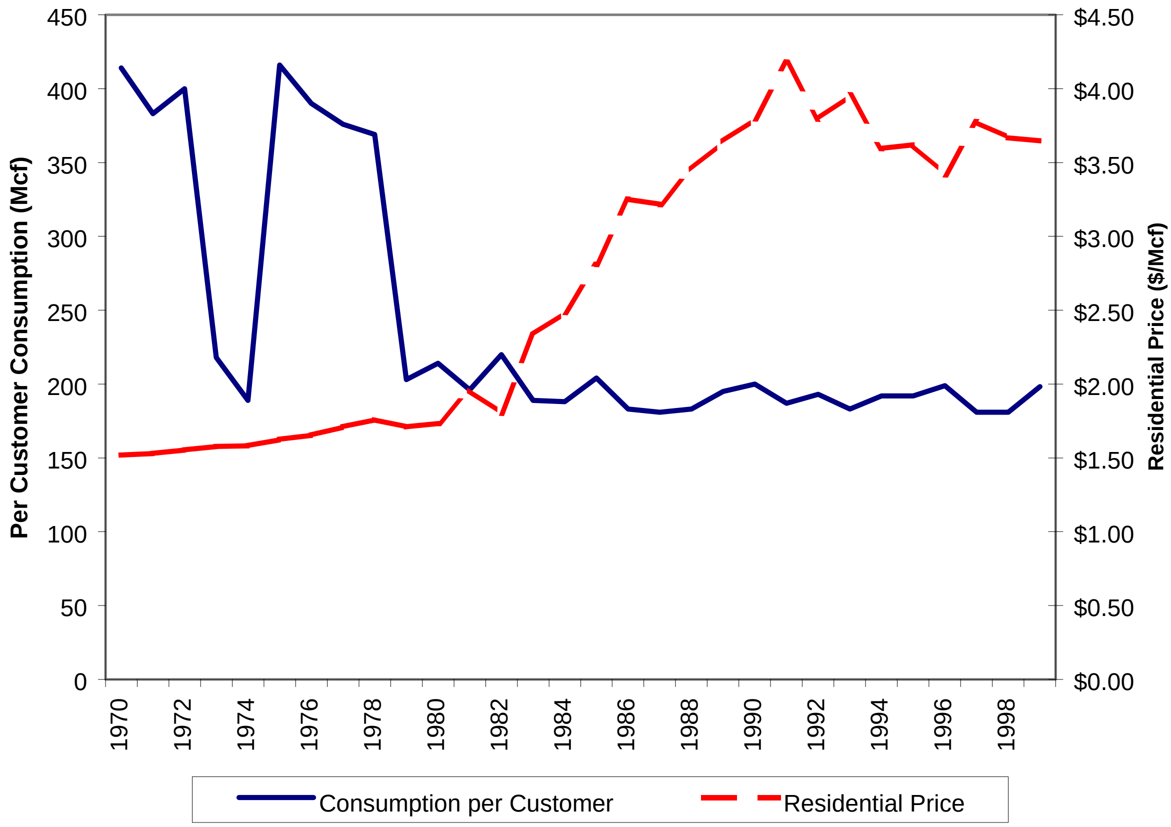

Figure A.1.6: Alaska Residential Average Usage and Price (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

A.1.5: Historic Commercial Natural Gas Usage Trends

Figure A.1.7 plots the relationship between customer growth and total usage for commercial customers. The trends represented in the graph are similar to those for residential customers. Again, during the period 1981-1984, there was a significant increase in the number of commercial natural gas customers. During this period, commercial usage also saw a relatively substantial leap – by as much as 20 percent between 1984 to 1985. However, commercial usage saw a sharp decrease in 1984, and followed a relatively stable trend until 1994, when usage for commercial customers saw another significant increase. Between 1994 and 1995 commercial usage increased by more than 20 percent.

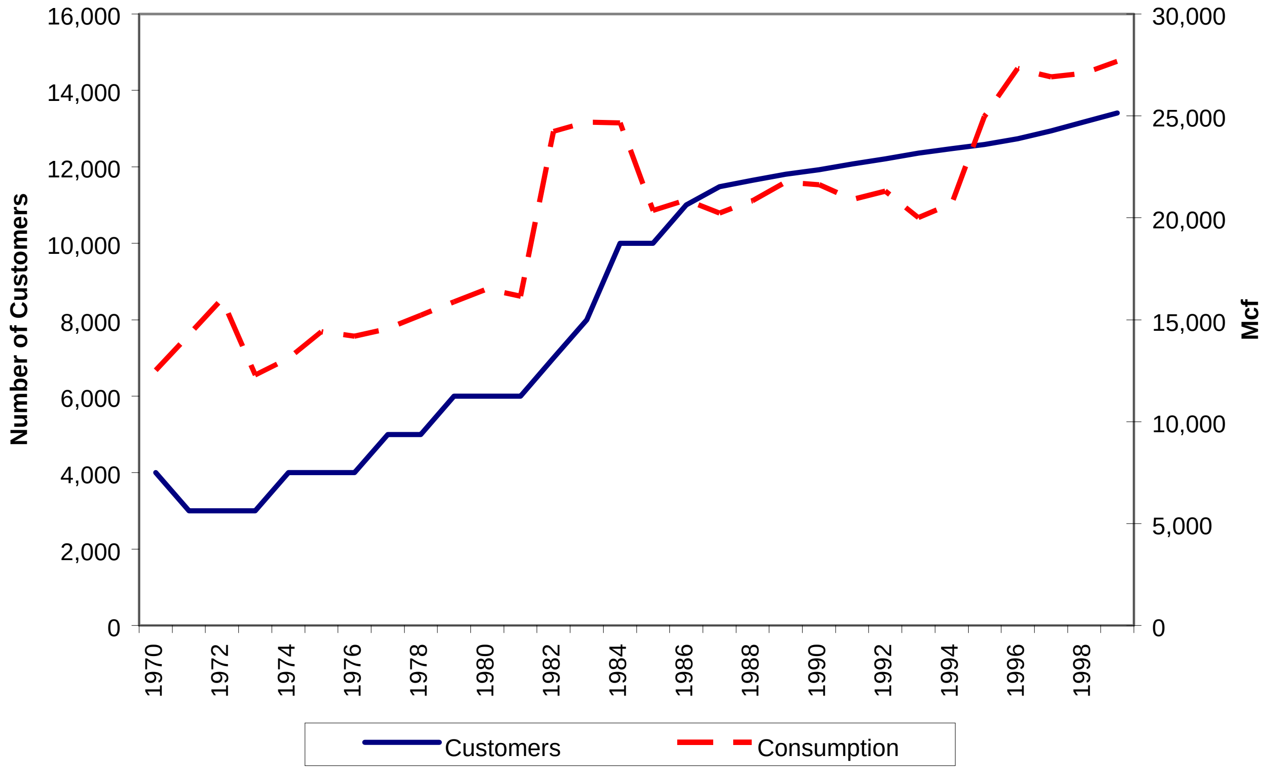

Figure A.1.7: Alaska Commercial Customers and Usage (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

Figure A.1.8 plots historic trends in average commercial usage and price. Overall, commercial customers tend to be relatively responsive to shifts in natural gas prices. During the period 1970-1981, natural gas rates were increasing, while average commercial usage fell. The sharp increases in commercial natural gas prices beginning in 1980 resulted in significant decreases in average commercial usage. For instance, during the period 1980 to 1985, commercial prices increased by 123.5 percent. During the same period, average commercial usage fell by 26.1 percent. In 1992, commercial prices began to fall again, while average commercial usage increased, albeit to a much less extent. Between 1992 and 1999, commercial prices have fallen at an annual average rate of 17.3 percent. Average usage, over the same period, increased at a rate of 18.2 percent.

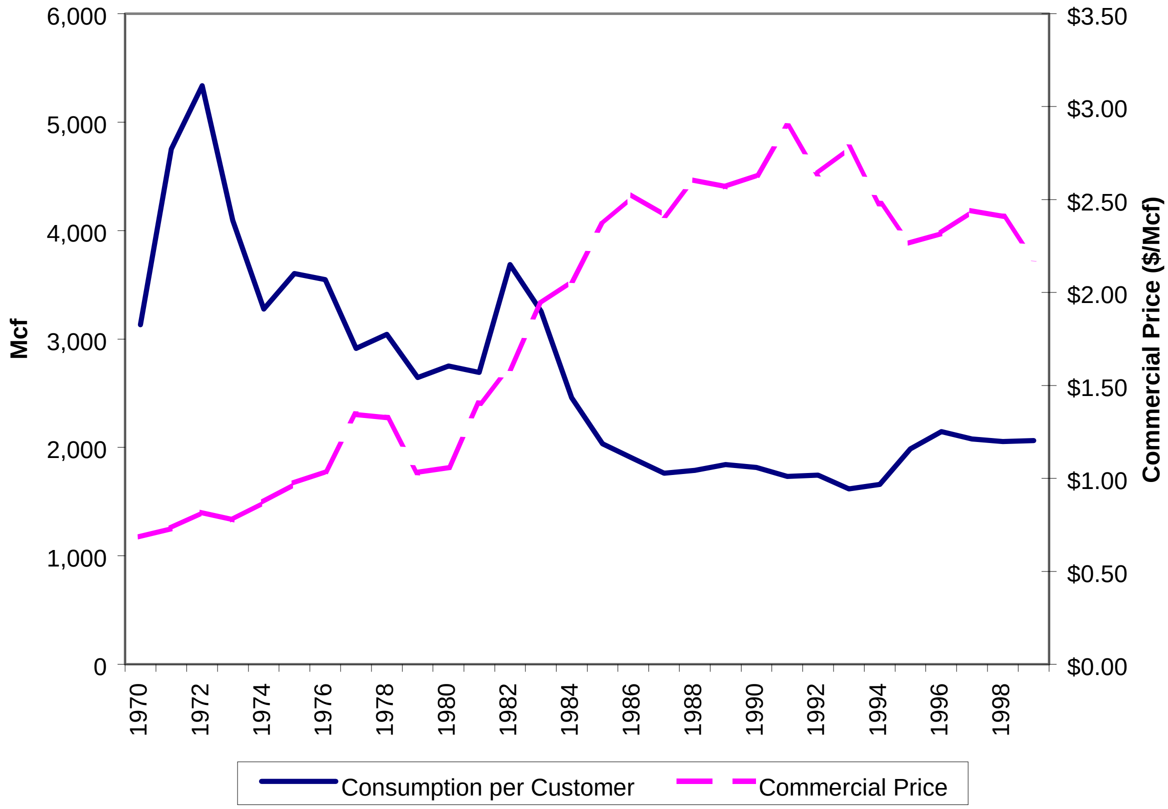

Figure A.1.8: Alaska Commercial Average Usage and Price (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

A.1.6: Historic Industrial Natural Gas Usage Trends

Figure 2.9 plots total usage and prices for industrial customers. Given the small number of customers in this class, average usage has not been presented because small shifts in customers can create large distortions in average usage. This figure highlights some of the problems associated with using average revenues as a proxy for price. For customer classes with small numbers of overall customers, like the industrial class in Alaska, sudden shifts in usage can be interpreted directly into shifts into average revenues, since they are simply the quotient of total revenues and sales.

Prior to 1989, industrial total usage and prices shifts followed similar patterns. For instance, between 1970 and 1979, both usage and prices (average revenues) increased for industrial customers. After 1979, both series saw dramatic decreases. From 1982 until 1989, both series followed a similar, and consistent, up and down movement. However, after 1989, natural gas prices and usage followed more traditional patterns, albeit with what appears to be a one year lag.

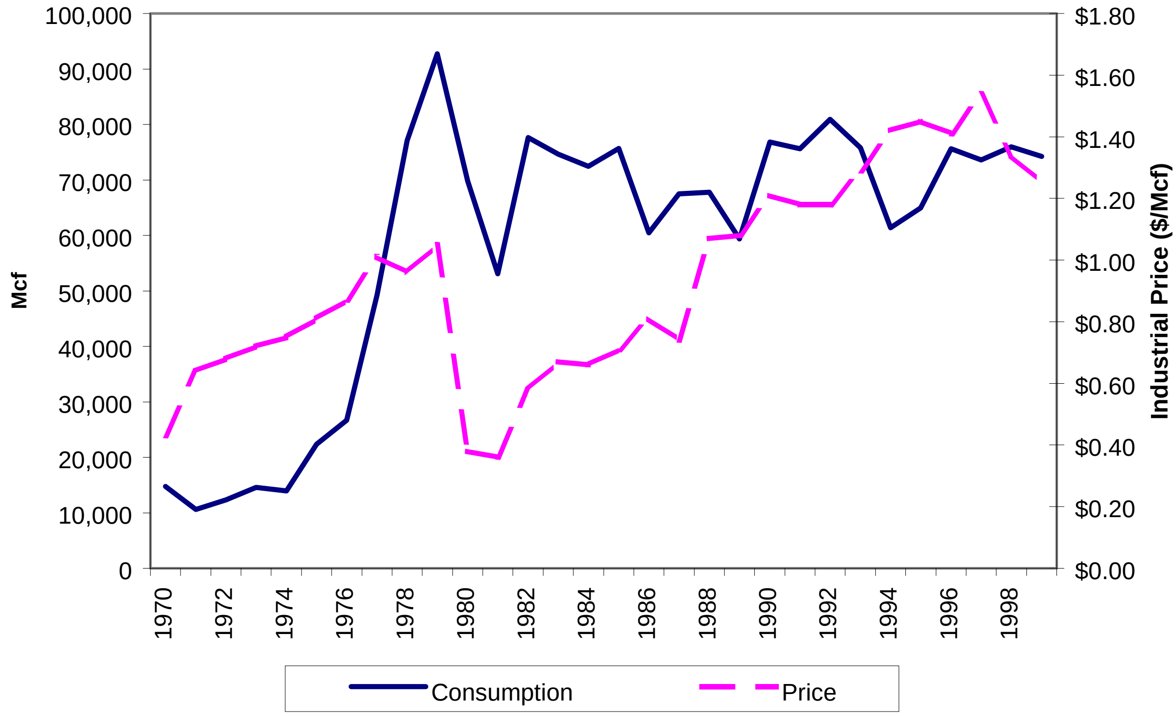

Figure A.1.9: Alaska Industrial Usage and Price (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

A.1.7: Historic Electric Utility Natural Gas Usage Trends

Historic electric utility usage and natural gas prices have been presented in Figure A.1.10. Given that electric utilities are required to generate electricity for their retail customers, and have historically had limited fuel substitution abilities, these trends may be more understandable. For instance, electric utility natural gas usage increased substantially throughout the 1970s and into the 1980. As will be seen later, this was also a period when electric customer growth was substantial and there was an increasing share of gas-fired generation to meet this new electricity growth.

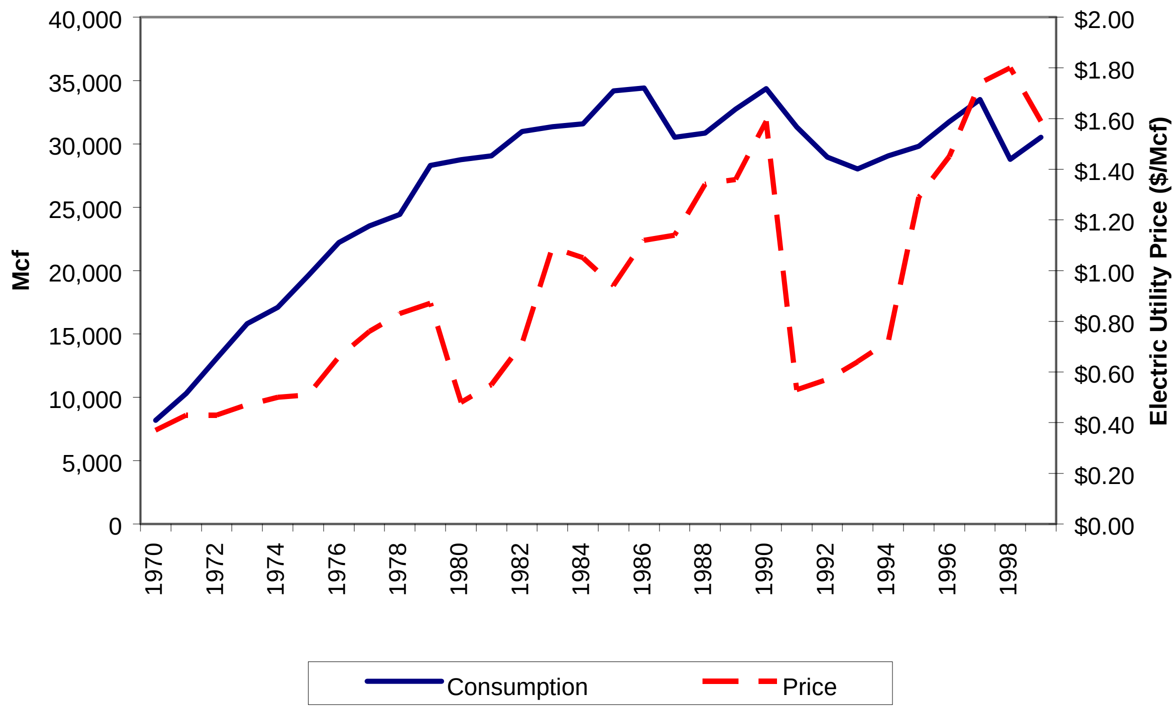

Figure A.1.10: Alaska Electric Utility Usage and Price (1970-1999)

Source: U.S. Department of Energy, Natural Gas Annual

A.1.8: Historic Electric Power Market Trends

Electric power generation is the second largest source of natural gas usage in Alaska. The demand for natural gas by electric utilities is driven by their need to generate electricity from gas-fired turbines and steam units. Understanding the changes in Alaska's power markets, therefore, can offer insights into how and why electric utilities have developed gas fired generating resources in the state. The following subsections offer some insights into changes in Alaska's power markets, and their implications for natural gas usage.

<u>**Electric Utility Customer Growth:**</u> Between 1970 and 1999, the number of electric utility customers in Alaska has risen by a dramatic 250 percent. This represents an average annual growth of 4.4 percent. As shown in Figure A.1.11, the trends of residential and total customers are very similar. Residential customers increased over 200 percent between 1970 and 1999, at an average annual increase of 4.3 percent. The largest increase occurred from 1983 to

1984, where the number of residential utility customers increased from 140,317 to 157,081, an increase of over 18,000 customers. Commercial customers have also followed this trend, increasing at an average annual rate of 4.5 percent. Industrial customers have also increased over the years at an average annual increase of 4.6 percent. Given their small relative numbers, industrial customers have been excluded from Figure A.1.11. In 1999, there were 473 industrial customers in the state. Over the period, growth for this class also averaged around 4.5 percent.

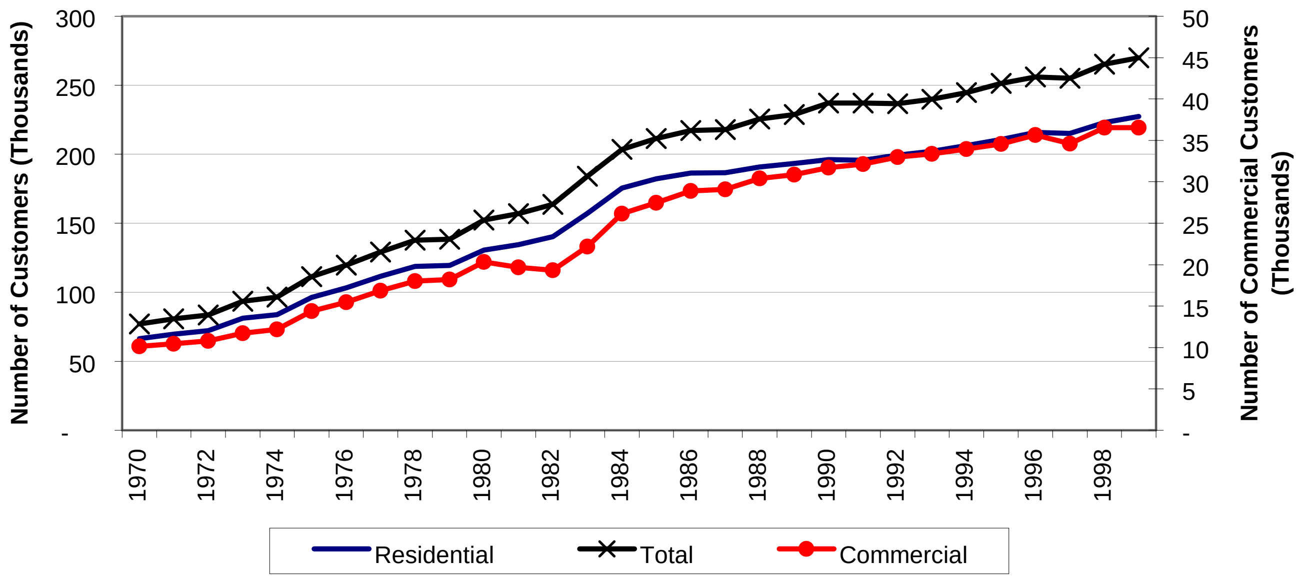

Figure A.1.11: Growth in Electric Utility Customers (1970-1999)

Source: U.S. Department of Energy, Electric Power Annual.

Electricity Usage Trends: Alaska's total electricity usage patterns followed a similar path to that of the number of customers. Total consumption increased by 379 from 1970 through 1999 – at an average annual rate of 5.6 percent. The largest increase was experienced between 1979 to 1982 when consumption grew from 1.07 to 1.67 billion kilowatthours (kWhs) representing a 57 percent increase. As shown Figure A.1.12, residential consumption rose steadily at an average annual rate of 4.5 percent. Commercial consumption increased significantly between 1983 and 1984, jumping close to 105 percent. Commercial electricity usage followed a more moderate growth trend from 1985 through 1999 at an average annual rate of 2.2 percent. Industrial usage followed a less consistent path from 1970 to 1984, and then evened out at an average annual rate of growth of 6.2 percent from 1984 through 1999.

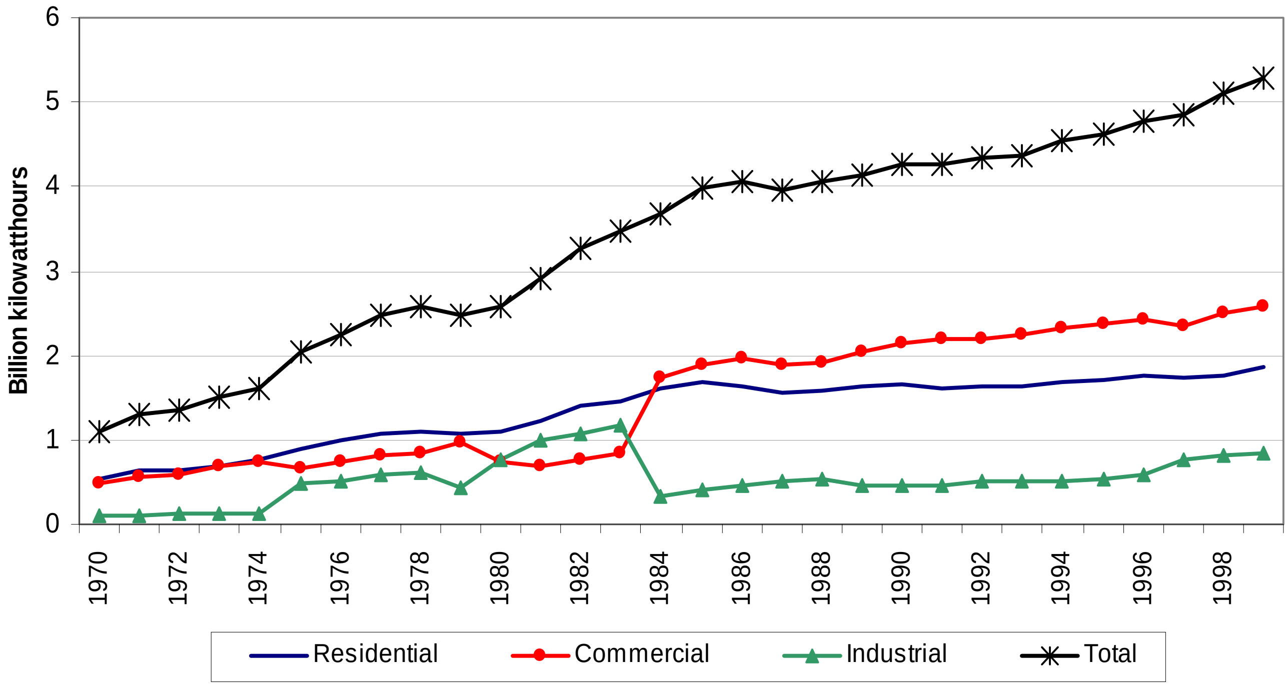

Figure A.1.12: Historic Electric Usage Trends by Customer Class (1970-1999)

Source: U.S. Department of Energy, Electric Power Annual

Retail Electricity Prices: Figure A.1.13 shows historic trends with real and constant dollar electricity prices. Here, electricity prices have been approximated on a per customer class bases by average revenues. There are three distinct trends in Alaska electricity prices over the past 30 years. The first trend occurred during the period 1970-1979, where electricity rates were only moderately increasing. The second trend occurred during the period 1979-1988, where electricity prices were growing rapidly as more power industry infrastructure was added to meet the state's increasing electricity needs. From 1988 onwards, electricity rates have followed a relatively flat growth rend in nominal dollars, and have actually decreased in constant dollar terms.

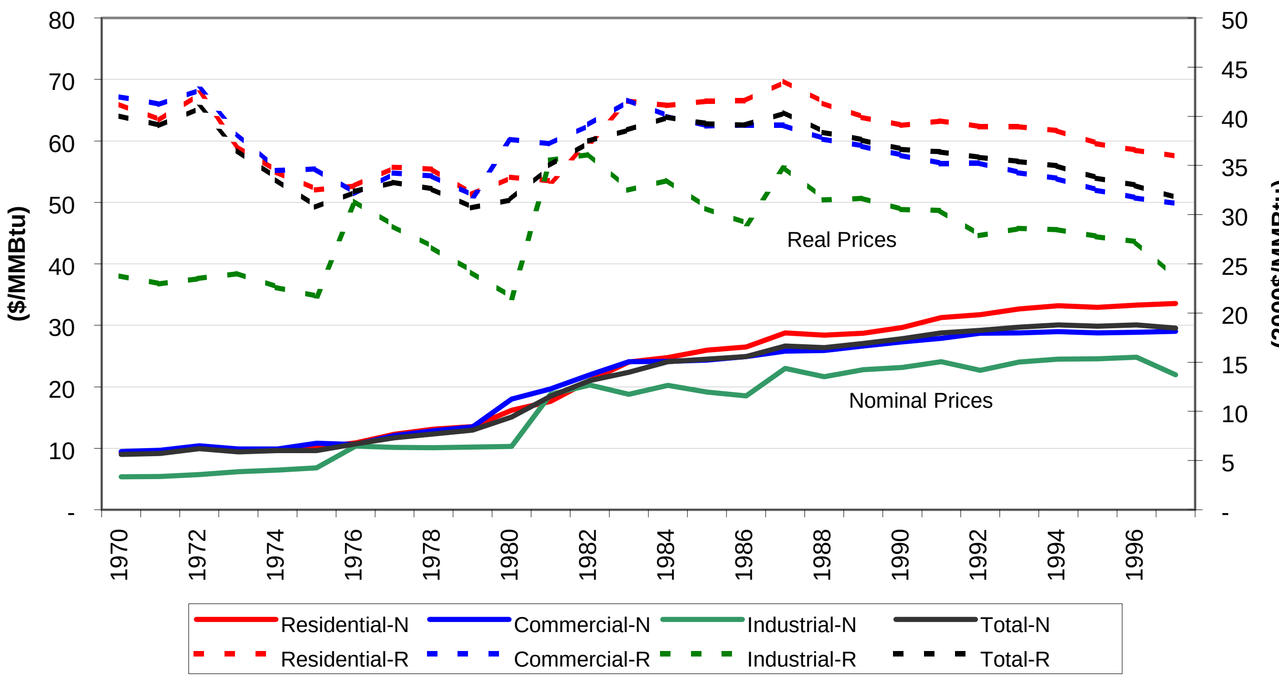

Figure A.1.13: Historic Trends in Electricity Prices Per Customer Class (1970-1999)

Source: U.S. Department of Energy, Electric Power Annual

Power Generation Trends: As of 1999 there are 676 electric generating units online in Alaska -- 567 of which are utility owned. These 676 units have a generating capability of 2,043 MW (1,743 MW or 85 percent for utility-owned units). According to the Energy Information Administration's Form 860, of the units that are still online, the oldest units are hydro powered. There are 6 units with generating capability of 6.9 MW that came online between 1900 and 1946. The first non-hydro unit was a unit fired by No. 2 Fuel Oil that came online in

1947. Since then, 475 utility-owned and 23 non-utility owned, oil fired units have come online – the majority of which (328) since 1980.

Figure A.1.14 shows the number of units by type of fuel and which decade they came online. This graph indicates that the majority of units (in number) are powered by fuel oil – especially those that have come online since 1970. Only 28 of the 567 utility-owned units are fired by natural gas, representing a capability of 666 MW. In contrast, 56 of the 109 non-utility owned units are natural gas fired, representing a generating capability of 161 MW.

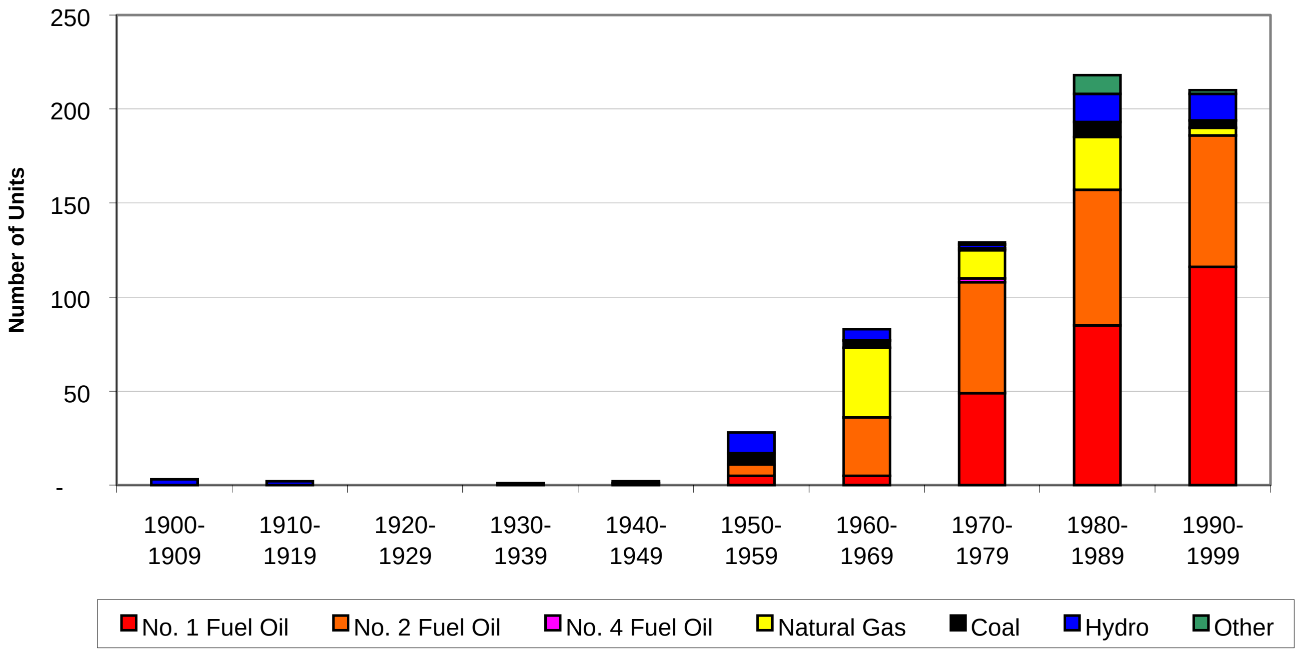

Figure A.1.14: Total Number of Generating Units in Operation by Year in Service and Fuel Type (Utility and Non Utility Owned)

Source: U.S. Department of Energy, Energy Information Administration: Forms 860A and 860B: Annual Electric Generator Report, 1999.

Although the actual number of natural gas fired units is significantly less than fuel oil, they do represent a considerably greater amount of generating capability than any other type of generating unit (See Figure 2.15). In fact, natural gas fired units represent over 40 percent of the generating capability of all the units currently online. Fuel oil units represent 30 percent and hydro units represent 18 percent of generating capability in Alaska.

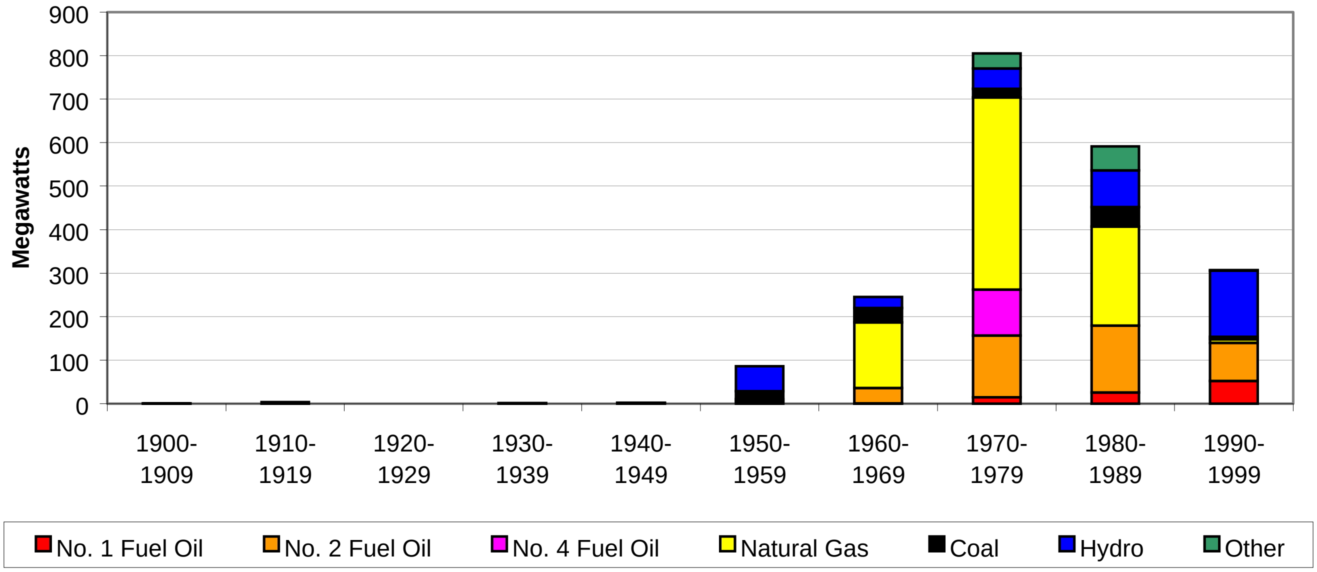

Figure A.1.15: Total Capacity of Generating Units in Operation by Year in Service and Fuel Type (Utility and Non Utility Owned)

Source: U.S. Department of Energy, Energy Information Administration: Forms 860A and 860B: Annual Electric Generator Report, 1999.

Net Generation and Fuel Consumption: Figure A.1.16 further demonstrates that natural gas-fired units play an important part in Alaska electric generation. An average of 2,600 GWh per year were generated by natural gas-fired units. Hydro plants generated an average of 1,100 GWh and fuel oil plants generated only about 550 GWh per year.

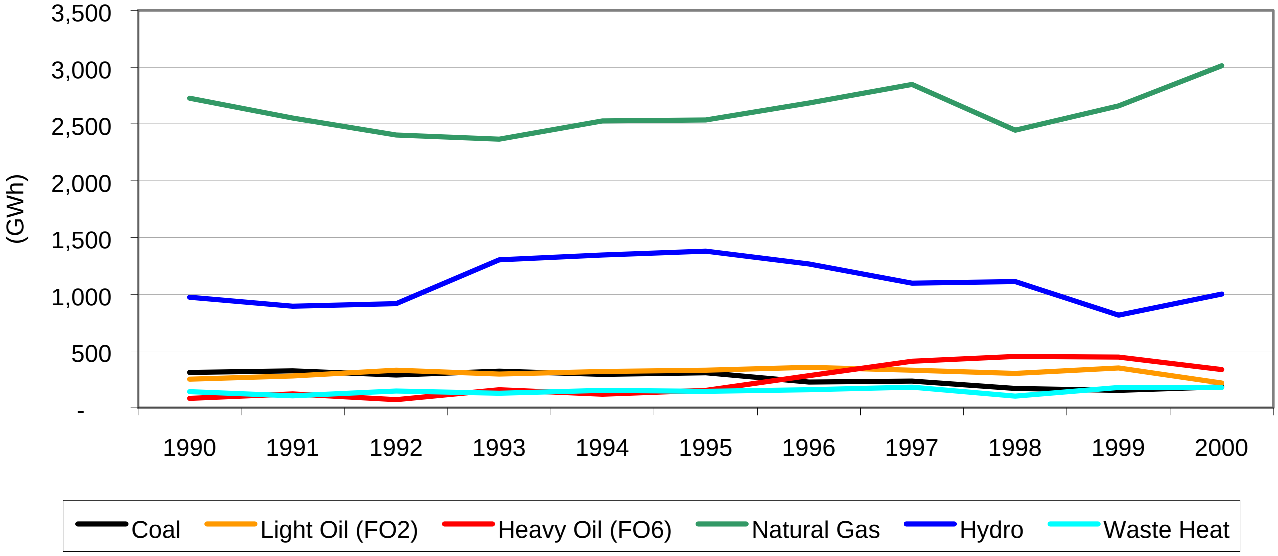

Figure A.1.16: Annual Net Generation by Fuel Type (1990-2000)

Source: U.S. Department of Energy, Energy Information Administration. Form 906: Power Plant Report, 2000.

APPENDIX 2
DETAILED REVIEW OF DEMAND AND SUPPLY MODELING LITERATURE AND DATA SOURCES USED IN THE BASELINE FORECASTS

This appendix has been offered as a substitute to Chapter 3 for those readers interested in greater detail on empirical modeling methods and the development of the literature.

A.2.1: General Issues in Modeling Demand and Supply

Modeling natural gas demand and supply in local, regional, and national markets is important for a number of reasons. These models give researchers and other market observers information about the structure and composition of demand and supply. Futhermore, the results of these models inform users about the magnitude of future demand and its sensitivity to key determinants such as energy prices and income. This information is used to understand:

- Past trends and the determinants of realized demand and supply;
- The responsiveness of demand and supply to changes in its important determinants; and
- Future demand and supply under different assumptions about future scenarios.

From its most basic perspective, the relationships of demand and supply can be summarized as:

- Demand is a function of prices, income, and tastes and preferences; and
- Supply is a function of input factor prices, technology, and other factors.

Transforming these theoretical relationships into measurable statistical equations is difficult. The way empirical data is measured may not conform with the structure implied by theory. For instance, theory suggests that the quantity demanded is a function of prices and other important variables. Yet the “appropriate” prices may not be readily available or easily generated. Furthermore, in many energy pricing situations, prices are set in a multitude of different manners (i.e, average rates, two-part tariffs, increasing block rates, decreasing block rates, time of day and seasonal pricing, etc.) Data measurement problems in terms of definition, sampling, and aggregation complicate model specification and statistical estimation.

Most quantitative analyses of supply and demand is broken into two types : cross sectional and time series. Cross sectional models typically examine causal relationships across a collection of variables over a fixed period of time. As suggested by the nomenclature, time series models focus on time dependency.

Cross sectional models are used to examine existing determinants of either supply and demand. These models are structural in nature since they attempt to flush out causality and typicially employ many different determinants of demand or supply as independent (explanatory) variables. Thus, a model of the industrial demand for energy, could consider a number of different explanatory factors that include economic characteristics (i.e., relative energy prices, output levels, etc.) and technical characteristics of the facilities (i.e., number of boilers, fuel switching abilities, heat to power ratios, etc.).

Cross sectional models provide useful information on the relative statistical importance of these variables at a given period of time but are less useful in estimating how relationships change over time. Thus, their ability to serve as a springboard for forecasting is limited. In addition, these types of approaches usually require detailed disaggregate information (usually at the firm or production unit level), that can be difficult to acquire, particularly for independent research.

Time series models, on the other hand, are more useful in examining the dynamic determinants of demand or supply. The advantage of time series models is that they can convey information about how supply or demand relationships have varied historically and where particular “structural breaks” in certain trends have occurred. These models are equally useful as a starting point for forecasting since most forecasts are developed from historical trend relationships. Their disadvantage is that data availability usually limits the range of the determinants measuring the supply or demand relationship.

Another consideration in time series models is that they can be developed in two different fashions. The first is traditionally referred to as an “econometric” approach while the second is commonly referred to more generally as a “time series” approach.[1] The econometric approach is concerned with the estimation of relationships suggested by economic theory across time. For instance, in demand analysis we might look at the relationship of energy demand relative to prices, income, weather, and other relevant variables. Such models serve two purposes. First, they allow economic hypotheses to be tested empirically.[2] Second, they provide a framework for making rational and consistent predictions (i.e., forecasting).

[1] A seminal text on the econometric analysis of time series is Andrew Harvey. (1991) *The Econometric Analysis of Time Series*. Second Edition. Cambridge, Massachusetts: The MIT Press.

[2] *Ibid.*, 1.

Pure time series approaches, on the other hand, are more generalized trend analyses based on statistical extrapolation techniques rather than theoretic relationships. Traditional time series analysis forecasts the time path of a variable with models that explicitly contain stochastic components to measure their dynamic relationships.[3] Difference equations, such as moving averages of either the error term, the dependent variable, or both, are at the core of these types of approaches. Uncovering the dynamic path of a series improves forecasts since the measurable components of the series can be extrapolated into the future.

There is a third option in facilitating what is known as cross-sectional/time series models. These approaches, as the name suggests, merge these two approaches to maximize the relative benefits, and minimize their relative shortcomings. The problem with these approaches is that, in many instances, they require relatively advanced statistical techniques, as well as being very data intensive.

Another important question in measuring either supply or demand relationships is the determination of which of the two general approaches should be facilitated. In many instances, this is usually done by purpose of the study as well as the practical limitations of the data. If a researcher is interested in examining the price elasticity of the residential demand for natural gas, then a cross sectional analysis of account-specific information would be a useful approach. However, many researchers outside of natural gas local distribution companies usually have limited to no access to this type of information. The US Department of Energy, however, does report aggregate information by customer class across time, thus some type of time series approach may be more readily facilitated.

Lastly, determining the appropriateness of a particular model is an important specification issue. Often, applied modeling can emphasize goodness of fit of a particular model to the expense of all other considerations. However, more balanced consideration should include such factors as:

- *Consistency with theory*. Ensuring the quantitative estimates of model parameters exhibit mathematical signs and magnitudes consistent with economic theory (i.e., negative price elasticities and positive income elasticities).

- *Consistency with goals*. Obviously specifying and measuring time series models can be more important for forecasting goals, while cross sectional models can be more important for research questions related to the relative importance of structural determinants.

[3] Walter Enders. (1995). *Applied Econometric Time Series*. New York: John Wiley and Sons, Inc.

- *Parsimony*. Ensuring that models that are not overly specified and are straightforward.

- *Robustness*. Ensuring that models are not overly dependent upon unique specifications or time periods under consideration.

The modeling of supply and demand for natural gas builds on a broad arena of industry-based energy modeling. Natural gas supply modeling, for instance, is conditioned by a number of earlier studies in petroleum supply modeling. Natural gas demand modeling is heavily linked to the electric power industry.

The study of natural gas supply and demand also is linked to technical-engineering models, sociological models, economic models, and hybrid models that employ varying combinations of these factors. Econometric analysis, as opposed to time series approaches, has dominated much of the supply and demand modeling literature as we will see in later chapters. The preference for these econometric approaches is probably to be expected. First, econometric approaches are useful in explaining the changes in natural gas disposition that result from general changes in the industry—particularly, the response to shifts in price and the general degree of price volatility in the industry since the early 1970s.

Second, while data measurement and implementation is still a challenge in the analysis of energy demand and supply, accessibility of the information has improved considerably. Reporting requirements and data collection developed at the U.S. Department of Energy gives researchers a consistent source of information to examine and corroborate existing studies in the energy industry. With the advent of the internet, the electronic availability of the information enhances the ability to concentrated important efforts in understanding empirical relationships rather than collecting basic information on industry disposition and trends.

Third, over the past twenty years, econometric approaches have become more accessible to industry practitioners as software packages have reduced the programming work needed to do the earlier models by an exceptional order of magnitude. Today, many readily available statistical packages can estimate either supply or demand models in matter of seconds. The reduction in computational difficulty has helped facilitate the development of a large body of analysis related to important energy relationships.

A.2.2: Empirical Studies of Natural Gas Demand

One of the pioneering authors in demand modeling, for many sectors that go beyond just energy demand modeling, is Hendrick S. Houthakker. His studies in energy demand modeling were extensive, and provided some of the first insights into the importance many structural determinants of energy demand. His work is still commonly cited in principals textbooks of microeconomic theory.[4] Houthakker's work in energy demand modeling, developed in the early 1950s, was a basis for his broader work in overall demand modeling.[5]

On the more practical side, there is a considerable amount of work in natural gas demand modeling that rests outside the traditional academic literature. This work is associated with the modeling conducted within the process of regulated natural gas distribution companies, commonly referred to as local distribution companies or LDCs. These LDCs use forecasting models for internal planning process in meeting supply (commodity) and capacity (transportation and storage) needs.[6]

Many of the theoretic developments of natural gas demand modeling have come from the academic literature. A good portion of this analysis has focused on residential, and to a lesser degree commercial, demand for natural gas. These models are primarily econometric in nature since the purpose of many are to get accurate estimates of price, income, and weather related sensitivities of natural gas demand.

Another practical consideration in reviewing the literature on natural gas modeling is its relationship with its sister energy industry, electricity. A number of the earliest works in energy demand concentrated in the area of electricity (i.e., Houthakker) and not natural gas. It seems likely that one of the initial reasons for more comprehensive development of demand modeling in the electricity industry is associated with its greater degree of data availability. Thus, any survey of natural gas demand modeling will have to include some references to the development in the power industry as well.

There are a number of surveys in the literature dedicated to natural gas and energy demand modeling in general. One of the earliest and most comprehensive surveys of energy demand modeling was prepared by Douglas R. Bohi for the Electric Power Research Institute (EPRI).[7] While the overall purpose of the study was to examine price elasticities, the study is an excellent overview of demand modeling since price elasticities are usually outputs derived

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[4]Hendrick S. Houthakker and Lester D. Taylor. (1966). *Consumer Demand in the United States, 1929-1970*. Cambridge: Harvard University Press.

[5]For instance see: Hendrick S. Houthakker. (1951), "Some Calculations of Electricity Consumption in Great Britain." *Journal of the Royal Statistical Socie*ty. Series A, 114, Part III, 351-71.

[6]A general primer on the role of natural gas demand forecasting and how it relates to overall LDC planning can be found in: Charles Goldman, et al. (1993). *Primer on Gas Integrated Resource Planning*. Berkeley, California: Lawrence Berkeley Laboratories.

[7]Douglas R. Bohi. *Price Elasticities of Demand for Energy: Evaluating the Estimates*. Palo Alto: Electric Power Research Institute.

from an overall analysis of demand determinants. An update to this study was prepared in 1984 by Bohi and Zimmerman.[8]

A more recent study, which emphasizes the development of the literature in residential energy demand modeling, was presented by Reinhard Madlener.[9] In the survey, Madlener attempts to update the earlier Bohi work, as well as breaking the existing econometric literature into a number of useful different categories. These include studies associated with log-linear functional forms, transcendental logarithmic (translog) functional forms, qualitative choice models (also know as discrete choice models), household production theory (end-use modeling), and pooled time series-cross sectional models.

Madlener presents a table associated with each of these types of models. We have replicated portions of that table, and added some supplementary comments and analysis, in Table A.2.1. Our survey will follow the same lines as Madlener, since it provides such a useful frame of reference to consider the development of energy demand modeling. The following survey will differ, however, by placing a larger explanation on the methods and their advantages, and highlighting in more detail, the seminal pieces of literature within each of these modeling categories. We also concentrate on the more generalized areas of: log linear and double log models, transcendental logarithmic (translog) functional forms, qualitative choice and end-use models (also know as discrete choice models).

A.2.3: Log-Linear and Double Log Models

The typical log-linear and double log models are relatively straightforward and tend to be the model of choice, particularly for industry practitioners. This model generally takes the form:

$$\log D = \beta_0 + \beta_1 P + \beta_2 Y + \beta_3 W + \beta_4 X \qquad \text{(eq. A.2.1)}$$

$$\log D = \beta_0 + \beta_1 \log P + \beta_2 \log Y + \beta_3 \log W + \beta_4 \log X \qquad \text{(eq. A.2.2)}$$

Where:

D = Natural gas demand
P = Price of natural gas
Y = Income
W = Weather
X = Other structural variables influencing demand
B = Estimated parameters.

[8]Douglas R. Bohi and Martin B. Zimmerman. (1984). "An Update on Econometric Studies of Energy Demand Behavior." *Annual Review of Energy*. 9: 105-54.

[9]Reinhard Madlener. Econometric Analysis of Residential Energy Demand: A Survey. *Journal of Energy Literature*. 2:3-32.

The benefit of the log-linear and double log form is that coefficients can easily be translated into elasticities. In the double log form presented in equation A.2.2, the parameter for price is interpreted as the price elasticity of demand, while the parameter estimate for income can be interpreted as the income elasticity of demand.

The log-linear literature starts with Houthakker and continues with Balestra and Nerlove (1966), who suggested a dynamic approach to the modeling of the demand for natural gas. This model contained a pooled cross sectional approach to modeling natural gas demand since it examined residential households, across several different regions, across time. The model is important since it uses an error-components specification and demonstrates the importance of relative fuel prices in determining both natural gas demand and fuel substitution.

For instance, in their study, Balestra and Nerlove assumed that the new demand for gas was a function of the relative price of gas and the total new requirements for all types of fuel. The problem with this approach was that the concept of new energy demand was difficult to translate into observable variables. The total new demand appeared as the sum of the incremental change in consumption and "replacement" demand, which represented the portion of the total demand for fuel "freed" by the retirement and replacement of old appliances. Specific equations were developed for each type of demand model, and ultimately fed into a larger equation examining total fuel use.

This total fuel use equation facilitated data from 1950 through 1962. The fuel use variables and price information was standardized into a Btu equivalent. Usage was normalized for weather in each state, and prices and income were measured in constant dollars. There were 13 observations per state, though only 36 states had gas service over the entire period. All states were grouped together and estimations were performed on the combined sample of cross sectional and time series data. Additional equations were estimated using dummy variables for each state.

While the estimation results presented negative and significant results for the impact of own price changes on energy demand, the greatest statistical significance rested with the state-specific dummy variables. The results would tend to suggest that there were a number of state-specific implications for energy usage that could not be directly modeled (i.e., regulation, etc.) The overall predictive capabilities of the model were very good, with 99 percent of the demand for natural gas being explained by the model's independent variables.

Because the demand function was for new gas demand, the average price elasticity was attainable from the model results. According to Balestra and Nerlove, the estimated average price elasticity of new gas demand ranged from –0.58 to –0.69 given the various functional forms estimated.

Beierlein, Dunn, and McConnon (1981) took the general framework discussed by Balestra and Nerlove and applied a Cobb-Douglas framework which has a double-log component. Their specification for energy demand included specific equations for fuel oil, natural gas, and electricity. This model is also a pooled cross-section approach since it examined energy usage across fuel type, state, customer class, including residential, commercial, and industrial, and year.

The independent variables were the average deflated price of gas per 1000 therms, the average deflated price per kWh of electricity, the average deflated price per gallon of fuel oil, lagged per capita fuel consumption, and per capita deflated income represented by disposable personal income, value of retail sales, and value added by manufacturing.

The model facilitated an error component and error component/seemingly unrelated regression (SUR) approach. The Cobb-Douglas framework allowed for constant elasticity of substitution, thus the estimated parameters for price, were the elasticities for each variable. The estimated own-price elasticity of gas for the residential sector was between –0.23 and –0.35 depending on the technique and between –0.61 and –0.63 for the natural gas industrial sector. The fit on the estimations showed that between 94 and 99 percent of the variation in the fuel consumption by various sectors was attributable to their respective independent variables.

The MacAvoy-Pindyck (M-P) model (1973) used similar techniques in what was a basically a demand component in a supply model.[10] In the demand module of this model, MacAvoy and Pindyck focused on wholesale natural gas markets. Supply of production out of reserves had to be measured against demand for the production after it had been transmitted to wholesale markets by pipelines, and the quantity demanded by direct industrial consumers as well as retail consumers.

MacAvoy and Pindyck modeled demand as a function of the prices for wholesale gas contracts, the prices for alternative fuels consumed by the final buyers, and economy-wide variables that determined the overall size of energy markets. For the model, the demands for production were approximated by curves fitted on a disaggregated basis into wholesale equations for (1) gas sales for resale,[11] (2) gas sales directly off the pipelines for final consumption (mainline sales), and (3) intrastate sales by producers and pipelines to final consumers. The wholesale prices of gas were computed by adding a markup to the field price based on (1) mileage between the production district and the consuming region, and (2) volumetric capacity of the pipeline.

[10] The discussion of the supply model can be found in the later section of this chapter on supply modeling.

[11] Split in to commercial-residential gas and industrial gas on the basis of percentages distributed to those two groups for ultimate consumption.

Before the wholesale demand equations were estimated, the M-P model looked at wholesale price markups. Markups over field prices were a function of mileage and volumetric capacity of the lines transmitting to each region. These field prices were the rolled in wellhead price for the wholesale region under investigation. The coefficient of volumetric capacity as determined by the M-P model was negative, as a larger capacity implies lower average costs. The fit of the estimated equation[12] showed that 56 percent of the variation in wholesale price of gas sales for resale could be explained the variation in the independent variables.

Gas sales for resale were broken down in to gas that ultimately is resold for residential and commercial consumption and gas for industrial consumption and the M-P model had a separate equation for each category for each of the five regions of the country. For each of these equations, new or additional demand was used as the dependant variable. The M-P model assumes that all fuel-burning equipment had an average lifespan of 14 years and chose a depreciation rate *r* equal to 0.07. Independent variables in the models included average wholesale price of gas, the wholesale price of oil, income, population, value added in manufacturing, capital investment by industry, and a price index of alternative fuels. In the South Central, Southeast, and West regions the residential and commercial sales were aggregated with industrial sales to make up for lack of stable elasticity estimates in the disaggregated form. All equations were estimated over the years 1964 through 1970.

Similar equations were developed for Northeastern region on a specific user basis. Results showed that an increase in the price of oil increases the demand for gas, additional units of value added in manufacturing increased the demand for natural gas, and additional units of capital investment increased the demand for natural gas.

MacAvoy and Pindyck, instead of using gas price for the current year, used the average wholesale price of gas for the previous two years and also did the same for the wholesale price of oil. The fit of this equation showed that 90 percent of the variation in total demand for the region was attributable to variation in the independent variables.

As noted earlier, additional units of capital investment in industry increased the total demand for natural gas. The fit of the equation showed that 80 percent of the variation in total demand for the region was attributable to the variation in the independent variables. The equation for Southeast-residential and commercial revealed that the coefficient for income is positive, which meant that additional units of income would increase the region's residential and commercial demand for natural gas. The fit of the equation showed that 26.7 percent of the variation in residential and commercial demand for the region was attributable to the

[12] As taken from each equation's R^2 values.

variation in the independent variables. The final regional gas sales for resale equation, that for Southeast-industrial demand, revealed that the coefficients for the price index for alternative fuels and value added in manufacturing exhibited a positive relationship. The fit of the equation showed that 37.3 percent of the variation in the industrial demand for the region was attributable to the variation in the independent variables.

The quantity of mainline sales to industrial buyers was estimated. The wholesale price for mainline sales was represented by the average of the wholesale price in the current year *t* and the previous year *t-1*. The same operation was also performed on the price index of alternative fuels. The coefficient of the price index of alternative fuels showed that an increase in the price index led to an increase in the quantity of mainline sales. The fit of this equation showed that only 15 percent of the variation in the quantity of mainline sales was attributable to the variation in the independent variables.

Finally, the quantity of intrastate demand was estimated. Like the mainline sales equation, the wholesale price of gas was represented by the average of the wholesale price for current year *t* and the previous year *t-1*. The fit of this equation showed that 21 percent of the variation in the quantity of intrastate demand was attributable to the variation in the independent variables.

Six of the ten demand equations had significant coefficients for the negative price effects on demand, with the strongest effects in regions closer to producing centers with more alternative sources of energy. MacAvoy and Pindyck concluded that size-of-market variables such as consumer incomes or industrial investment did not appear to be causal factors in all sectors of the natural gas market.

MacAvoy and Pindyck also calculated interregional flows of gas in order to be able to calculate excess demand of consuming regions. Estimates of interchange at an aggregate level were made using the five demand regions, West, Northeast, North Central, Southeast, and South Central, and eight production regions. Total flow, the fraction of a consuming region's demand which comes from a particular production region, and the fraction of gas from a production region going to a particular consuming region were calculated. Demand was forecasted for the period 1966 through 1970, and the mean demand error[13] was –2.5 Tcf with an RMS[14] demand error of 2.5. Estimated demand quantities for each year were about 13 percent lower than the actual values.

[13] Mean error is the average of the errors of the predicted values. The error of a predicted value is calculated by subtracting the actual value from the predicted value.

[14] RMS error, or Root Mean Square error, is simply a quantitative measure of the deviation of model predictions from actual observations. Smaller RMS error is better.

Lyness (1984) developed a gas demand forecasting model which focused on the temperature-gas demand relationship. He identified three regular cyclical patterns in gas demand: (1) the diurnal swing during each day, which had peaks at breakfast time and the evening and a trough during the night, (2) a weekly cycle, and (3) an annual cycle related to seasonal changes in temperature. All three cycles were superimposed on each other and were treated as being related.

Lyness forecasted long-term demand almost exclusive on temperature and the underlying concept of seasonal normal temperature (SNT). For each day of the year a long-run average temperature could be derived and those could be smoothed to form a sinusoidal curve for the entire year. Thus daily, weekly, or monthly SNT's were known in advance and the forecast of demand for the remainder of the year was obtained through the insertion of the appropriate SNT values into the current forecast demand and temperature relationship.

While he provided no specific model for the forecasting of temperature, Lyness did provide two ways to look at this variable. The approach considered, within a linear framework, a number of different seasonal, daily, and temperature influences on natural gas demand. Lyness left the addition of market data to the individual modeler, as different regions had different market conditions and thus market variables. The model was broken down in to separate equations corresponding to the market sectors. For each forecast year, parameters in each market sector equation were scaled in the ratio of the forecast annual market sector demand to the current market sector demand and then re-aggregated to arrive at an equation for the forecast year that was consistent with the total forecast demand for that year.

Herbert and Kriel (1989) built on the studies by Beierlein (1981), Grady (1986), Green (1987), Blattenberger (1983), and Lin (1987) by creating a natural gas demand model which incorporated both heating degree day data as well as wealth data, and estimated the model based on monthly information. The main equation in the model estimated monthly aggregate residential sales as the function of six variables: (1) the index of changes in total personal income in constant dollars received by gas customers and changes in the number of gas customers, (2) heating degree days weighted by gas residential space-heating customers, (3) cooling degree days weighted by population, (4) household wealth in constant dollars measured by financial and non-financial asset holdings, (5) the price index of natural gas in constant dollars, and (6) the seasonal shift in residential gas demand for the one-month period from mid-December to mid-January.

Weighted heating degree days were indexed to changes in the percentage of space-heating to total gas customers. The authors also estimated regressions for real wealth, which was a function of time, and real personal income, which was a function of the number of residential customers in a given quarter and Census Division and personal income in a given quarter and Census Division.

The fit of the estimated equation showed that 99 percent of the variation in monthly aggregate residential sales was attributable to the variation in the independent variables. The model was used to forecast values for the year 1984, and the mean error was 217 Mcf and individual differences ranged from one percent to five percent.

Hsing (1992) built on the work of Taylor (1977), Blattenberger (1983), and Griffin (1979) in an exercise for estimating the own-price and income elasticities of natural gas for each of the 50 states except Hawaii for the year 1989. The model had the demand for natural gas for each state in a given period as its dependent variable. The independent variables included the price of natural gas, disposable income per capita, the price of residential electricity, and the number of heating degree days. The model also included dummy variables for the South (SO) and West (WE) as well as the years 1985 and 1986 but no reason is given for these inclusions.

Hsing estimated the elasticities from the results of the linear regression of the model. His results included Alaska-specific estimates of –0.29 for the price elasticity of demand and 0.37 for the income elasticity of demand.

A.2.4: Transcendental Logarithmic (Translog) Models

Translog models became popular in the 1960s with the advent of the Christensen, et al. (1973) approach of estimating industrial production, and later with utility functions.[15] This approach was applied to the electric power industry in 1976, and the approach has become commonplace for a considerable amount of energy economics research.[16]

The translog specification is a quadratic function with its elements expressed in terms of their natural logarithm. This specification is a second order approximation around a given point for the Cobb-Douglas production function. The Cobb-Douglas production function is a flexible functional form for a production function that allows declining marginal products for all inputs, and also assumes that opportunities exist to substitute inputs in production without gaining or losing output.

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[15] Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1973) "Transcendental Logarithmic Production Frontiers." *The Review of Economics and Statistics*. 55:28-45. Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1975) "Transcendental Logarithmic Utility Functions." *The American Economic Review* 65: 367-83.

[16] Laurits Christensen and William Greene. (1976). "Economies of Scale in U.S. Electric Power Generation." *Journal of Political Economy*. 84 (4): 655-76.

The advantage of the translog approach is that it provides some structure on the assumed production/utility function under investigation. The parameters associated with the own and cross-price terms provide estimates of own and cross-price elasticities of demand. In additional, the translog approach allows for a more flexible functional form that enables empirical validation of utility-function properties. For example, while the Cobb Douglas function imposes unitary elasticity of substitution among inputs, the translog enables the data to determine the degree of input substitutability. In general, this flexible functional form enables the data to determine if the assumed functional form is correct, and imposes fewer a-priori restrictions on model specification.

The approach, however, is not without its potential problems. First, translog models require a significant amount of information which can be difficult to attain. Second, these models can be relatively difficult to apply and interpret. This has led many practitioners to steer clear of these approaches. Third, the parameter estimates in many instances do not tend to be robust or stable, and can lead to some erroneous results. Last, the model tends to lend itself better to cross-sectional analyses, and, as a result, is not a very useful tool for forecasting.

The translog specification[17], usually takes the form:

$$\log D = \beta_0 + \beta_1 \log P + \beta_{11}(\log P)^2 + \beta_{12}(\log P)(\log Y) + \beta_{13}(\log P)(\log W) + \beta_{14}(\log P)(\log X) + \beta_2 \log Y + \beta_{22}(\log Y)^2 + \beta_{23}(\log Y)(\log W) + \beta_{24}(\log Y)(\log X) + \beta_3 \log W + \beta_{33}(\log W)^2 + \beta_{34}(\log W)(\log X) + \beta_4 \log X + \beta_{44}(\log X)^2 \qquad \text{(eq. A.2.3)}$$

Where:

- D = Natural gas demand
- P = Price of natural gas
- Y = Income
- W = Weather
- X = Other structural variables influencing demand
- β = Estimated parameters.

Christensen and Jorgensen introduced the translog approach in 1969 and then again with Lau in 1973, and Pindyck (1979) used the approach extensively to analyze demand in his work on world energy demand. Estrada and Fugleberg (1989) took Pindyck's work and applied it to the natural gas markets in West Germany and France in order to determine own-price and cross-price elasticities of demand. Using a translog equation based on Pindyck's, Estrada and Fugleberg estimated a number of equations for the household and commercial sectors:

The resulting equations included estimates with lagged price variables in order to test the underlying hypothesis that long-term changes in the composition of

[17] From Brynjolfsson and Hitt (1995).

energy demand were the result of changes in relative fuel prices, infrastructural changes in the economy, and the technology incorporated in equipment used to consume different fuels. The authors hypothesized that the response to an increase in the relative prices of fuels would take one to two years as consumers replaced their old equipment with types that were more energy efficient.

The actual estimation of the elasticities was done using a two-step process, the first of which was the calculation of partial own-price and cross-price elasticities: The second step was to incorporate the partial elasticities in to equations for total elasticities. The authors found that the own price elasticity for gas was much higher in Germany and believe that this was because the German government did not regulate prices as much as the French, and changes in fuel costs were more rapidly reflected in consumer prices.

A.2.5: Qualitative Choice and End Use Models

Most demand models prior to the early to mid 1970s, and even to this day, facilitate continuous variables for consumption. There are equally interesting empirical applications that examine not how much of a particular resource is utilized, but whether or not that resource is utilized at all. Such approaches are discrete in nature and have led to the development of qualitative choice, or discrete choice models of energy usage.

Discrete choice models are those in which the dependent variable is a discrete variable. The simplest application is one where the dependent variable is a binary choice variable that represents a simple positive or negative response. The dependent variable takes the value 1 if the choice is made, and 0 if the choice is not made. Independent variables are then used to estimate parameters influencing that choice.

Consider a generalized binary choice model that takes the form:

$$y = x\beta + e \qquad \text{(eq. A.2.4)}$$

Where:

y = A discrete variable (eg. gas heating) that takes the value 1 if the choice is made, 0 otherwise

x = A matrix of explanatory variables, such as characteristics of the alternatives or socioeconomic variables

β = A vector of parameter estimates

e = A sequence of error terms which can take either logistic or normal distribution

Discrete choice models can be powerful tools to examine individual customer choice behavior and the factors influencing those decisions. Sensitivities, developed through the calculation of odds ratio statistics, can then be derived. These odds ratio statistics given some indication on how the probability of making a particular discrete energy consumption decision change as the independent variables change.

These qualitative based models, however, usually require specific and relatively comprehensive end use information. Typically, data used in these types of analyses are from individual consumer surveys. Thus, such empirical approaches are limited, if customer, or decision making unit information is not available. In addition, these types of models can tend to be more static in nature making it difficult to use for long forecasting and trend analysis.

Some of the representative works in this area include the work of the State Utility Forecasting Group (1999) in Indiana, which used a logit form of discrete choice model to determine fuel choice among residential energy consumers. The dependent variable of the model was the ratio of electricity's share of the space heating market to that of all other fuels. Market share was used because it captured current activity, was independent of the rate of customer growth, and exhibited greater year-to-year variation than measures of market saturation. The group used a double-log functional form of the logit model, which allowed for easy calculation of elasticities. The national energy outlook model released by the Energy Information Administration (2001) also used discrete choice modeling for fuel choice components of the overall model.

A.2.6: Relevant Literature in Natural Gas Supply Modeling

Unlike the natural gas demand literature, natural gas supply modeling has been relatively restricted to log-linear or double log functional forms.

Some of the earliest natural gas supply models were developed in the early 1960s starting with Adelman (1962) and Fisher (1964). Adelman's work specified two distinct equations for natural gas production. The first equation defined a simple relationship between price of non-associated[18] natural gas and production. The second equation was more forward looking by specifying that the production of natural gas in year *t+1* was a function of price in the previous year. In other words, production decisions were based upon a lagged function of price.

Adelman found there was a positive relationship between the price and supply of natural gas in both types of models. His model provided quantitative estimates of the sensitivity of natural gas production to price (i.e., price elasticity of supply).

[18]Non-associated natural gas is the production of natural gas that is not the byproduct well that is not primarily designated as producing oil. Hence, its primary function is to produce natural gas.

Adelman found that a one cent increase in the price of natural gas brought about a 750 to 1,000 Bcf increase in non-associated gas reserves. In the model where production was posited to react to current prices, Adelman found that 60 to 66 percent of the variation in the quantity supplied can be statistically explained by the variation in price. In the models where production is a lagged function of price, Adelman found that 75 percent of the variation in the quantity supplied can be statistically explained by the variation in price. The result tended to support the notion that while production was highly sensitive to price, it did respond instantaneously.

Two years later, Fisher (1964) focused on the sensitivity of petroleum exploration and discovery to economic incentives. Fisher examined four different types of equations as being potentially important determinants of petroleum exploration and discovery. The natural logs of four facets of production, including the number of new field wildcats drilled, the success ratio of productive to total new field wildcats, the average size of oil discoveries per productive new field wildcat, and the average size of gas discoveries per productive new field wildcat, were the dependent variables in their respective equations. The independent variables, however, varied per equation and included the average depth of new field wildcats, crude oil and natural gas prices, and core drilling time.

The effective value of new discoveries in Fisher's model was calculated as being the product of the number of wildcats drilled, the success ratio, and the average size of discovery per successful wildcat. Fisher examined production trends during the period 1946-1954 and found that all four equations had good fits. The predictive capabilities of each of these models varied between 72 to 85 percent

Fisher's models also produced estimates of the elasticities of wildcat drilling to the price of crude oil. He also found that the elasticity of wildcat drilling with respect to the price of crude was about +2.85, which meant that a one percent increase in the deflated crude price of oil at the wellhead resulted in a 2.85 percent increase in the number of new field wildcats drilled. The elasticity for the relationship was +2.45, or a one percent increase in the deflated crude price of oil resulted in a 2.45 percent increase in the number of new wildcats drilled, when shutdown days and lagged depth were included in the equation.

Fisher's hypothesis that price affected the characteristics of prospects was supported, as the elasticity of the success ratio with respect to price was –0.36, indicating that for a one percent increase in the deflated price of crude oil, the resulting success ratio of productive to total new field wildcats decreases by 0.36 percent, showing a worsening of prospect characteristics when prices rise. As well, the price elasticity of oil discovery size was –2.18 and the price elasticity of natural gas discovery size was –2.01, which meant that a one percent increase in the deflated price of crude oil resulted in a 2.18 percent decrease in the average size of oil discoveries and a 2.01 percent decrease in the average size of gas discoveries, thus as price rose, the number of small prospects that were deemed worth drilling rose as well. Fisher's estimations showed that the price elasticity for both new oil and new gas discoveries was +0.9, where a one percent increase in the deflated price of crude resulted in a 0.9 percent increase in new oil and gas discoveries, though he hypothesized that the price elasticity result from a separate estimation of +0.3 was closer to the truth, as he believed that new oil and gas discoveries were less price responsive than his original estimations showed.

Fisher concluded that there was an important substantive distinction between the supply curve of exploratory effort and the supply curve of new discoveries. Fisher found that economic incentives not only influence the quantity of exploration that occurs; they determine its characteristics, as a price increase could bring about added discovery in more marginal fields.

The regulation of natural gas ceiling prices in the early 1970s brought about the next wave of natural gas modeling, and in 1971 the results of two models, the Khazzoom Federal Power Commission (FPC) (1971) model and the Erickson-Spann (1971) model, were published.

The Khazzoom model focused mainly on gas discoveries, as Khazzoom claimed that discoveries were the driving force behind gas supply. The model was split into two sections, the first being "new discoveries," which represented the amount of recoverable gas estimated to exist in newly discovered reservoirs and the second being "extensions and revisions," which consisted of additions to or subtractions from the initial estimates of gas discovery due to changing economic conditions or the availability of new information on reservoir size or reservoir characteristics. Both parts of the model also included a dummy variable for each of the six groupings of the 21 FPC districts included in the study,[19] and each part of the model was estimated with and without the dummy variables.

The new discoveries equation included new discoveries in time *t* as the dependant variable. The independent variables were the real ceiling price of gas, the real price of crude oil at the wellhead, the real price of liquefied gases and ethane, and a new discoveries variable. Because of the specification of the equation, each dependant variable was "lagged," which means the actual values used to determine new discoveries at time *t* are taken from previous periods. In this case, the values used are the average of the variables in periods *t-1* and *t-2.* Khazzoom found that the independent variables explained 79 percent of the variation in new discoveries, though the prices of oil and liquefied gas and ethane were statistically insignificant.

The extensions and revisions equation included independent variables representing the ceiling price of gas, the real price of oil, and the real price of liquefied gases and ethane, new discoveries from the previous year and

[19] The six groupings were Upper Gulf Coast (UG), Gulf Coast (GC), South Mid-Continent (SMC), Panhandle-Hugoton (PH), Permian Basin (PB), and Rocky Mountain (RM).

extensions and revisions from the previous year were also included. The results for this equation were much better when the FPC district groupings were included, because without them every price in the equation was statistically insignificant and with them only the price of oil was insignificant. Overall, the independent variables explained 61 to 64 percent of the variation in extensions and revisions.

Pindyck (1974) criticized the use of a lagged dependant variable in Khazzoom's model, stating that the lagged variable in the new discoveries equation accounted for too much of the variation in new discoveries in time *t*, thus making the estimates of the price coefficients inconsistent. Pindyck also reestimated Khazzoom's model for the years 1964 through 1969 (as opposed to the original estimation period of 1961 through 1969). Due to lack of data, the variable for gas liquids was eliminated. The number of dummy variables was reduced as well, as only three regional variables were used instead of six.

In the re-estimation of the new discoveries equation, Pindyck found that only the significant coefficient was that of the lagged new discoveries variable, though the fit of the equation increased to where 89.5 percent of the variation in the dependent variable could be explained by the variation in the independent variables. The improved fit of the equation was explained through the elimination of years 1961 through 1963 in which prices and discoveries had the greatest variation.

Pindyck's reestimation of the extensions and revisions equation, again with the elimination of the gas liquids variable and three of the regional variables, over the years 1964 through 1969, resulted in findings similar to those of Khazzoom's, with the exception of insignificant coefficients for the constant, the price of gas, and one of the three regions. The fit of the equation increased from 63 percent in Khazzoom's estimation to 81.4 percent of the variation in the dependent variable attributable to the variation in the independent variables, though as previously stated, this had to do with the elimination of the years 1961 through 1963. Again, criticism is levied at the use of lagged dependent variables, as the lagged new discoveries and extension and revisions variables account for much of the variation in the dependent variable.

The Erickson-Spann (E-S) (1971) model focused on the price responsiveness of new discoveries of natural gas. The basic relationships estimated by Erickson and Spann were the price elasticities of wildcat well drilling and total discoveries,[20] the success ratio, and average discovery size.[21] Erickson and Spann defined wildcat well drilling as a measure of the amount of exploratory effort undertaken in a given period and the success ratio and average discovery size are measures of the results of this activity. Total discoveries were defined

[20] Price elasticity of total discoveries is the sum of the price elasticities of each of the component elements whose product is total discoveries.

[21] The success ratio, average discovery size, and prices are all measured in logarithms.

as the product of the number of wildcat wells multiplied by the fraction of the wildcat wells that are successful multiplied by the average discovery per wildcat well.

Erickson and Spann used four equations in their model: “wildcatting;” the “success ratio;” “average oil discovery size;” and the “average gas discovery size.” The equations were all estimated for the years 1946 through 1959.

The wildcatting equation had the logarithm of the number of new field plus new wildcats drilled as its dependent variable. Independent variables measured as logarithms included the deflated price per barrel of crude oil at the wellhead, deflated wellhead price per thousand cubic feet of gas by year of basic contract, success ratio of the previous year, and average depth of wildcats the previous year, in feet. Independent variables not measured as logarithms were the number of wildcats drilled by major companies in a given district in a given year as a percent of total U.S. wildcats drilled by those companies in that year, Texas shutdown days, and dummy variables for each petroleum district. The resulting fit of the equation was quite good, with 97.2 percent of the variation in the logarithm of the number of new field wildcats drilled attributable to the variation in the independent variables.[22]

The success ratio equation had as its dependent variable the logarithm of the success ratio, which is the ratio of productive to total new field plus new pool wildcats. The independent variables were the same as the wildcatting equation with the exception of the logarithm of the lagged success ratio, wildcats drilled by major companies, and the logarithm of the average depth of wildcats drilled. The fit of the results of this equation was also good, with 80.2 percent of the variation in the logarithm of the success ratio attributable to the variation in the independent variables.

The average oil discovery size equation had as its dependent variable the logarithm of the average size of oil discoveries per productive new field plus new pool wildcat. The independent variables were the same as for the success ratio equation with the inclusion of the logarithm of the lagged success ratio. As was the case with the two previous equations, the fit of the resulting equation was good, with 89.3 percent of the variation in the logarithm of the average oil discovery size attributable to the variation in the independent variables.

The average gas discovery size equation had as its dependent variable the logarithm of the average size of gas discoveries per productive new field plus new pool wildcat. The independent variables were the same for this equation as they were for the average oil discovery size equation. The resulting equation

[22] Erickson and Spann made little mention of the significance of the coefficients other than to say that they were “not especially satisfactory” for each equation. The reason for this was that there were missing gas prices for eleven observations in PAD districts I-IV, thus reducing the number of observations over 20 percent.

does not have as good a fit as the three other equations in the model, with only 60 percent of the variation in the logarithm of the average gas discovery size attributable to the variation in the independent variables.

The significant contribution of the E-S paper was the model's ability to calculate elasticities. Erickson and Spann found the own price elasticity of gas discoveries to be +0.69, meaning that for the time period 1946 through 1959, a one percent increase in the price of gas lead to a 0.69 percent increase in gas discoveries. This own price elasticity was the sum of the elasticity for wildcat drilling, which was +0.35, the success ratio, which was +0.01, and the average gas discovery size, which was +0.33.[23] The overall cross elasticity of gas supply with respect to oil price was –0.25, meaning that for the time period, a one percent increase in the price of oil resulted in a 0.25 decrease in the supply of gas.[24]

Pindyck (1974) reconfigured the E-S model to exclude unavailable data such as company specific wildcatting and Texas shutdown days, and reestimated the reconfigured model with data from 1964 through 1969. The fit of the estimated equations left much to be desired, as the success ratio and discovery size equations both had 75 percent of the variation in the dependent variables *not explained* by the variation in the independent variables. As well, Pindyck's estimated own price elasticity of gas was +2.36, far higher than Erickson and Spann's estimation of +0.69. Pindyck cited the size of discovery equation as the source of the problem, as a small change in price tended to result in large increases of average discovery size.

Natural gas shortages in 1970 and 1972 provided the impetus for the creation of two new supply models published in 1973, the Total Energy Resource Analysis (TERA) (1973) model, and the MacAvoy-Pindyck (1973) model.

The focus of the MacAvoy-Pindyck (M-P) model was the simultaneous treatment of the field market for reserves[25] and the wholesale market for production.[26] This structure allowed the M-P model to incorporate the linking of the two markets by interstate pipeline. MacAvoy and Pindyck also stressed the importance of incorporating the demand side of the gas industry, especially when policy implications are involved in the modeling process. Khazzoom, Erickson, and Spann are complimented on their efforts to create supply models, but the models themselves are deemed inadequate to represent policy effects.

The field markets were defined as the point of transactions between oil and gas producers with volumes of newly discovered reserves and pipeline buyers

[23] Erickson and Spann also calculated a similar set of elasticities for crude oil and found the own price elasticity of crude oil to be +0.83.

[24] Conversely, the overall cross elasticity of oil supply with respect to gas price was calculated to be +1.07.

[25] Gas producers dedicating new reserves to pipeline companies at the wellhead price.

[26] Pipeline companies selling gas to retail utilities and industrial consumers.

seeking to obtain by contract the right to take production from these reserves. The amount of reserves committed by the oil and gas companies were based primarily on the amounts of inground deposits of oil and gas, with additions to the reserves coming from additions in gas associated with newly discovered or developed oil reserves ("associated" gas) as well as gas volumes found in reservoirs not containing oil ("non-associated" gas).

MacAvoy and Pindyck also noted that any economic modeling of the gas industry should take into account the depletion effect on reservoirs, using indicators of depletion or of decreasing returns as variables explaining supply. Four important characteristics of field markets were identified: (1) more gas will be made available for sale if the buyers offer higher prices, (2) the lag adjustment process bringing forth additional supplies of reserves is likely to be long and complex, (3) production out of reserves is determined by a combination of technical and economic circumstances but is likely to be greater the larger the volume of reserves available and the higher the contract prices pipelines are paying for the gas they are taking, and (4) demands depend on prices but are also derived from final residential, commercial, and industrial consumption.

The first equation of the M-P model dealt specifically with the additions to reserves. Total gas reserves were calculated as the sum of reserves from the previous year, new discoveries of both associated and non-associated gas, extensions of associated and non-associated gas, revisions of associated and non-associated gas, minus changes in underground storage, and subtraction resulting from production.

The section of the M-P model representing the field market contained nine equations, seven of which were stochastic and two of which were identities. Most of the data used was from the years 1964 through 1971. The first two field market equations were identities representing associated and non-associated discoveries. Associated discoveries equaled the associated average discovery size multiplied by total exploratory well drilling. Non-associated discoveries equaled the non-associated average discovery size multiplied by total exploratory drilling.

Exploratory well drilling was found to respond to three economic incentives. The first was the deflated[27] lagged total revenues from sales of new oil and gas at the wellhead, which were used as a surrogate for anticipated returns from exploration. The second incentive was the deflated lagged average total drilling costs. The final incentive was the measure of relative risk between different regions. Relative risk between different regions, which is not time sensitive, is the sample variance, measured over recent years, of payoff size in each district.[28] The estimation of the equation showed that all three incentives have

[27] Deflated by a GNP price index.

[28] Districts included were Louisiana South, the Permian region, and Oklahoma, Kansas, and Texas Railroad Commission Districts 2, 3, and 4.

significant coefficients, thus drilling increases as lagged prices increase and lagged costs and risk decrease. The fit of the equation tells us that 49.5 percent of the variation in exploratory well drilling can be explained by the independent variables.

The equation for non-associated average discovery size had as its dependent variable the average discovery size of non-associated, or gas only, discoveries. The independent variables were the average wellhead price of gas for the three previous years, the average drilling costs per well of exploratory drilling for the previous three years, and the cumulative number of wells drilled for the previous year. The cumulative number of wells drilled was used to represent the depletion variable. Three regional dummy variables are also included in the equation. The fit of the equation was such that 63 percent of the variation in the non-associated average discovery size was attributable to the variation in the independent variables.

The equation for associated average discovery size was similar to that for non-associated gas, with except that the average price of oil was substituted for the price of gas. The fit was similar to the non-associated equation, with 60 percent of the variation in associated average discovery size attributable to the variation in the independent variables.

Both average discovery size equations showed strong lag effects of the price and cost averaging as well as strong depletion effects. The price of gas was found to have a strong positive effect on the size of non-associated gas discovery, while the price of oil had a negative but insignificant effect on the size of associated gas discovery.

Extensions of both associated gas and non-associated gas are accounted for with separate equations that differ only in the new discoveries variable. The independent variables for the equation were total exploratory drilling for the previous period and previous gas discoveries. Regional dummy variables were also used. The fits for both equations were good, with 72.5 percent of the variation in non-associated extensions and 69 percent of associated extensions attributable to the respective independent variables.

The revision equations for both associated and non-associated gas were the same except for the dependent variable. The revision of both associated and non-associated gas were a function of the regional variables and the change in the previous period's reserves of gas. MacAvoy and Pindyck ceded that associated revisions were erratic and difficult to explain with a simple linear regression model and admitted that their identification of the relationship between associated revisions and the lagged reserves of gas was dubious.[29] Neither

[29] MacAvoy and Pindyck stated that the associated reserves are tied more closely to oil reserves, but chose not to model that relationship.

equation had explanatory power, with R^2 values of 0.289 and 0.398 for associated and non-associated, respectively.

The next section of the model differentiated production out of reserves[30] between Louisiana South and the rest of the United States, as Louisiana South had cost characteristics that required separate treatment. Both Louisiana South and the rest of the United States had total production regressed against the log of the wellhead price of gas and total reserves. The rest of the United States equation included the dummy variables for the Permian region and Oklahoma, Kansas, and Texas Railroad Commission Districts 2, 3, and 4. The fit of this equation showed that 83 percent of the variation of total production for the rest of the United States can be explained by the variation of the independent variables.

The Louisiana South equation was similar to the rest of the United States equation with the exception of the dummy variables and too had a good fit, with 96.4 percent of the variation in Louisiana South total production attributable to the variation in the independent variables. Both equations showed positive and significant effects of prices and total reserves, thus with higher prices, both short-run and long-run production should increase.

A historic simulation of the M-P model for years 1966 to 1970 showed that the error of the forecasts was relatively small. The mean supply error was 0.3 Tcf, with a maximum overestimation of 1.9 Tcf and a maximum underestimation of 1.5 Tcf. Error for demand of production was slightly larger, with a mean error of –2.5 Tcf. The model routinely underestimated demand over the simulation period, though MacAvoy and Pindyck explained this by citing overestimations of wholesale prices over the same period.

The revised work of Pindyck (1974) has already been discussed in terms of specific reestimations of the Khazzoom and E-S models, but the ultimate goal of his 1974 work was to take the Khazzoom and E-S models and simulate them as part of the M-P model.

Because the Khazzoom model predicted both new discoveries and extensions and revisions, the two equations from the model were substituted for the seven equations of the M-P model that predicted wells, discoveries, extensions, and revisions. The E-S model predicted only new discoveries, so Pindyck substituted it for only the new discoveries equations in the M-P model, and retained the four extension and revisions equations. Pindyck reestimated the M-P model three times for the period of 1965 through 1971, once with each alternate insertion, and once with the straight M-P model. The key areas estimated were new discoveries, additions to reserves, and supply of production.

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[30] Production out of reserves as a function of price was the marginal cost in the short-term of developing existing reserves so that a particular level of flow could be achieved.

Pindyck found that over the seven years from 1965 through 1971, the straight M-P model, with the smallest mean errors and RMS error, performed best in terms of new discoveries. The Khazzoom formulation had the lowest RMS error for additions to reserves, but Pindyck questions the level of meaning behind this because (1) the Khazzoom extensions and revisions equation depends on new discoveries, which were being underpredicted, thus if Khazzoom's new discoveries performed better the extensions and revisions would perform more poorly and (2) the previously mentioned autoregressive component of Khazzoom's equation helps the equation pick up the trend but not turning points, thus it is not as useful an equation for policy analysis. All three formulations of the model performed about equally well in terms of supply of production.

A forecast through 1980 was also performed, using two alternative sets of assumptions. The first set of assumptions was called "cost of service," in which price increases were set at one cent per Mcf per year. The second set was called "deregulation," and a 15 cent per Mcf increase in price was set for 1974, with four cent per Mcf per year increases each year following. For both sets of assumptions, other variables were assumed to take "medium" growth paths.

Forecasts using the Khazzoom model showed a lack of price sensitivity, as there was no response in reserve additions in response to increases in wellhead prices. Even under the deregulation set of assumptions, excess demand reached 7 Tcf by 1980. On the flip side, the forecast using the E-S equations was so price sensitive that by 1980, the industry had produced an excess supply of 18 Tcf. Right in the middle of these two extremes was the M-P model, which eliminated excess demand by 1979 under the deregulation assumptions and had an excess demand of 10 tcf under the cost of service assumptions.

In 1977, Neri (1977) released an evaluation of the TERA and M-P models. He simulated both models over the historical period of 1965 through 1972 and the forecast period 1975 through 1980. Over the six year historical period, the M-P model performed best in terms of drilling, new discoveries, and production. Neri found that both models tend to overpredict drilling activity, new discoveries, and additions to reserves. Both models had low RMS errors for gas production, with the TERA model overpredicting and the M-P model underpredicting.

Neri also performed long-run forecasts with both models for the period of 1975 through 1980. Two policy simulations were used. The first considered regulation and set the wellhead price for new contracts at $0.50/Mcf, and allowed then to rise at $0.01/Mcf per year. The second simulation considered phased deregulation and set the wellhead price at $0.65/Mcf and allowed contracts to rise at $0.05/Mcf per year. The forecast results for the models were very different, with the TERA model forecasting reserve additions 30 to 50 percent lower than the M-P model, and with each model's production forecasts moving in different directions. Under both situations, the TERA model predicts a reduction in the production of natural gas, while the M-P model predicts significant growth in production under both situations. The TERA model's 1980 price elasticity for production is 0.06, while the M-P model has a price elasticity of 0.24. Neri cited several reasons why the divergence occurred, including differences in accounting for drilling success, discovery size, extensions and revisions, offshore discoveries, and production, and concluded that there is no precise way to decide which forecast is preferred.

Huntington (1990, 1992) summarized the work performed by the Energy Modeling Forum working group. The group focused on the evolution of the North American natural gas market through 2010. Two types of models were used within the group, both of which used a partial equilibrium framework to determine gas prices and quantities. The first type of model was spatial equilibrium models, which focused on the equilibria between different region markets, and the second type was engineering-economic simulation models, which focused on the processes and determinants of gas supply and demand.

Table A.2.1. Summary of the Strengths and Weaknesses of Modeling Approaches

Approach	*Strengths*	*Weaknesses*
Log-linear/double-log	1) Relatively easy to specify and estimate 2) Estimated coefficients are directly interpretable as short-run elasticities, and long-run elasticities are easy to calculate 3) Estimated standard errors provide measure of the variability of the estimated elasticities	1) Constant elasticity assumption often unrealistic and not justifiable 2) Sometimes problems of consistency with the underlying economic theory 3) Appropriate only when one has reason to believe that the variables enter multiplicatively in to the equation
Translog	1) Imposes a minimum of restrictions on demand behavior and is very flexible 2) Firmly based in economic theory 3) Particular demand characteristics are testable (eg. separability, homotheticity, etc.) 4) Allows the analysis of substitutional relations	1) Sometimes lack degrees of freedom due to the large number of regressors 2) Only well-behaved for a limited range of relative prices 3) Estimated elasticities are not directly interpretable 4) More complicated estimation techniques are required 5) Static formulations dominate
Qualitative choice	1) Appropriate when dependent variable comprises a finite set of discrete alternatives 2) Relatively easy to estimate 3) Flexible specification 4) Tobit models allow for observations to equal zero	1) Inefficient estimates in the case of zeros (logit, probit) 2) Theoretically not based on assumptions of utility maximization (logit) 3) Relies on rich and reliable data sets
Pooled time series/cross-section	1) Pooling enables greater efficiency of the estimates	1) Only makes sense if the cross-sectional parameters are constant over time 2) Difficult specification

Source: Madlener (1996)

A.2.7: Methods and Data Used to Develop the Baseline Demand Model

As noted above, there are a number of empirical modeling techniques that have been facilitated in the literature. However, one of the most common and successful approaches for examining natural gas demand are the log-linear and double log models first developed in the 1960s. Our baseline models of natural gas demand are based upon those approaches. There are a number of advantages associated with the traditional double-log models. These include:

- They are straightforward approaches that are parsimonious and flexible;
- They are general models that are applicable to a wide range of data;
- In the absence of detailed, account specific survey data, these models serve as the best approach for fitting demand curves for the broad customer classes we are examining (i.e., residential, commercial, and industrial);
- The majority of the past academic and trade literature has been based upon these approaches; and
- These approaches have the advantage of providing considerable descriptive information in addition for being good tools for developing forecasts.

We have developed baseline models for each major consuming sector in Alaska's natural gas markets. These include residential, commercial, industrial, and electric utility.

In looking at natural gas demand our goal was to find a consistent source of information that was documentable and widely accepted as authoritative. Based upon our past experience, we have found that the information provided by the Department of Energy, Energy Information Administration (EIA) provides the most comprehensive, and documentable source of information for natural gas usage. This information is compiled annual by the EIA in EIA Form 176. A discussion of EIA Form 176, and the data collected in this annual survey, has been provided in Chapter 2.

APPENDIX 3
DETAILED DISCUSSION OF BASELINE IN-STATE DEMAND MODELS: STATISTICAL MODELS AND RESULTS

A.3.1: Introduction

Our modeling approach has attempted to use widely accepted statistical approaches for developing estimates of in-state natural gas demand. The goal has been to develop a statistical understanding of the important determinants of Alaska natural gas demand, and then use this information to develop forecasts of potential in-state natural gas usage.

One issue driving our modeling approach was data availability. Given time and resource constraints for this project, we attempted to facilitate the best available information to estimate Alaska natural gas demand. Our primary source of information for current in-state natural gas demand comes from Form EIA-176. This form, providing local distribution company (LDC) and transportation company natural gas disposition information, is a required filing to the US Department of Energy. Information is collected annually and is broken out by major customer class. This data was used to form the core of the forecasting approach.

The empirical forecasts have been developed in a three fold manner. First, structural models were developed that facilitate a traditional econometric approach. This econometric approach examines the relationship of natural gas usage for each customer class based upon changes associated with income, prices, weather, and other important determinants of natural gas demand.

Second, a trend, or time series, approach was developed to model in-state natural gas demand. This time series approach simply looks at the underlying trend relationship in usage growth over time. This approach is useful because it extrapolates longer term trends over an extended period of time without regard to the underlying reasons for those shifts.

Third, a combination forecast was developed that combines the structural, or econometric approach, with the trend analysis. Such an approach helps pick up the peaks, valleys, and underlying trends in data and is a useful tool for forecasting.

The econometric models are based upon the double-log methods described in Appendix 2. In general, these models examine the statistical relationships between usage, as a dependent variable, and prices, weather, and income as independent variables. These models work well in measuring shifts in consumption due to shifts in the underlying explanatory variables. They work well in capturing the ups and downs of energy consumption, but can be less accurate out over long forecasting periods.

The double log econometric based approach was chosen for several reasons. First, one goal was to facilitate methods that could be applied to a general, documented, and reliable source of detailed natural gas usage data. The primary source of information used in this study came from the EIA-Form 176 database. The double log methods used in this model fit will with the data, and provide a convenient method by which independent researchers could verify and replicate the results of this study.

Second, the double log models that have been facilitated in this research, while perhaps not the most sophisticated in the academic literature, are the most common for developing econometric natural gas usage models. Forecasting practitioners for both electric and gas utilities use these approaches on a regular basis. The popularity of these approaches are evident by the large number of companies, as well as their respective regulatory commissions, that use them on a regular basis.

In addition to the standard econometric approach, the baseline in-state natural gas usage models are also comprised of an overall time series model of natural gas usage on a per customer class basis. The time series model use straightforward stochastic approaches to "trend" natural gas usage. These forecasted time series, or trends, are then extrapolated into the future to develop forecasts of natural gas usage. These time series models work well in predicting long run averages, but are not very instructive in providing information on the underlying empirical determinants of natural gas demand.

The last approach utilized is referred to as a combination of forecasts, or amalgamated forecast. This approach was developed by Newbery and Granger (1974).[1] The Newbery and Granger approach showed that if two forecasts are developed that have no consistent biases, then the combination of these forecast will be unbiased. This approach allows us to combine the strengths of both the econometric and time series approach to develop an overall forecast that incorporates known empirical determinants of natural gas demand, and a trend component.

A.3.2: Residential Natural Gas Demand Models

The results from the residential natural gas usage econometric model are presented in Table A.3.1. The model uses total residential natural gas usage as its dependent variable. Independent, or explanatory variables, include price, income, heating degree days, and number of customers. Early empirical analysis indicated that there appeared to be some lagged response to prices,

[1]P. Newbery and C.W.J. Granger. (1974). "Experience with Forecasting Univariate Time Series and the Combination of Forecasts." *Journal of the Royal Statistical Society*. 137: 131-46.

particularly with residential and commercial customers. As a consequence, prices were modeled as a polynomial distribution lag.

A polynomial distributed lag, or PDL, is a common form of finite distributed lag that accounts for delayed responses in consumption relative to changes in price. The PDL posits that the total response to a shift in a dependent variable does not come all at once, but over a period of time. From a practical perspective, using PDLs in price terms allows the modeler to estimate both short run and long run price elasticities of demand. The terms are cumulative, thus, the summation of all the parameter estimates for price, over the period examined, provides an estimate of the long run price elasticity of demand.

The overall residential econometric model results are highly explanatory as represented by the adjusted R-square value. The parameters for most all of the explanatory variables, with the exception of customers, was statistically significant at commonly accepted values. The number of heating degree days exhibited the strongest statistical properties in the model. The elasticity with respect to the weather is 0.56, indicating a one percent increase in heating degree days would increase residential usage by 0.56 percent.

Income also tended to be a highly significant empirical determinant of residential natural gas usage. The econometric model estimates an income elasticity of approximately 1.5 which is a strong degree of income responsiveness. This would entail that a one percent increase in income results in a 1.5 percent increase in residential natural gas usage.

Pricing terms were equally significant from a statistical perspective, and validated the use of the one-period PDL. Table A.3.1 shows two price elasticity values, representing current and lagged term effects.

Table A.3.1: Econometric Results from Residential Natural Gas Demand Model

Variable	Coefficient	Standard Error	t-Statistic
Intercept	-5.8853	2.8533	-2.06
Polynomial Price Terms			
Current Period Price	-0.2042	0.1078	-1.89
Lagged Price (t-1)	-0.1021	0.0539	-1.89
Income (PCI)	1.4991	0.5170	2.90
Heating Degree Days	0.5574	0.0922	6.05
Customers	0.1946	0.2685	0.72
Adjusted R^2	0.982		

The estimate a short-run price elasticity of demand is –0.2042. The lagged price elasticity of demand for residential customers is estimated to be –0.1021. The sum of these parameter estimates (–0.3063) represents the total, or long run, price elasticity of demand. Longer lag structures were explored, but the one period lag produced the best statistical fit since other lag period proved to be statistically insignificant.

The parameter estimate for the lagged price term is –0.1021 indicating a decaying response to shifts in consumption due to changes in price. Such a result is consistent with other demand models, and the general body of work on estimating price elasticities of demand.

The econometric model was subjected to a number of commonly accepted statistical diagnostic techniques. Of particular concern in most time series models is the potential presence of autocorrelation: or a correlation in the error term of the model over time. If not corrected, autocorrelation can lead to unreliable tests of statistical significance. An examination of the results of the residential model indicated a potential problem with first order autocorrelation. The final results presented in Table A.3.1 have been corrected for this potential bias.

The time series model of residential natural gas demand was developed using the SAS/ETS (Econometric Time Series) software and SAS-based "Time Series

Forecasting System." The Time Series Forecasting System forecasts future values of time series variables by extrapolating trends and patterns in the past values of the series. The system provides both graphical and statistical features to help choose the best forecasting method for each series. In selecting the best model for natural gas demand by customer class, the Time Series Forecasting System automatic model fitting option was utilized. This option allows a user to find the best model by trying on over 40 different functional specifications (e.g., Holt exponential smoothing, random walk with drift, variously parametrized ARMA and ARIMA models) for time series analysis. Since the trends and temporal patterns of natural gas demand vary by customer class, we use different time series models for each variable. The statistical results for the residential time series model have been presented in Table A.3.2.

Table A.3.2: Time Series Results for Residential Natural Gas Demand Model

Residential Log Linear Trend Model	Parameter	Standard Error	t-Statistic
Intercept	16.292	0.021	786.41
Linear Trend	0.024	0.002	10.03
R Square	0.883		
Mean Absolute Percentage	2.905		

A graphical representation of the econometric and time series models has been presented in Figure A.3.1. This figure has four different lines represented the actual and forecasted values for residential natural gas usage. The analysis is limited to the historic period over which the forecast was developed. The figure has been provided to give the reader an understanding of each model's fit relative to the historic actual values.

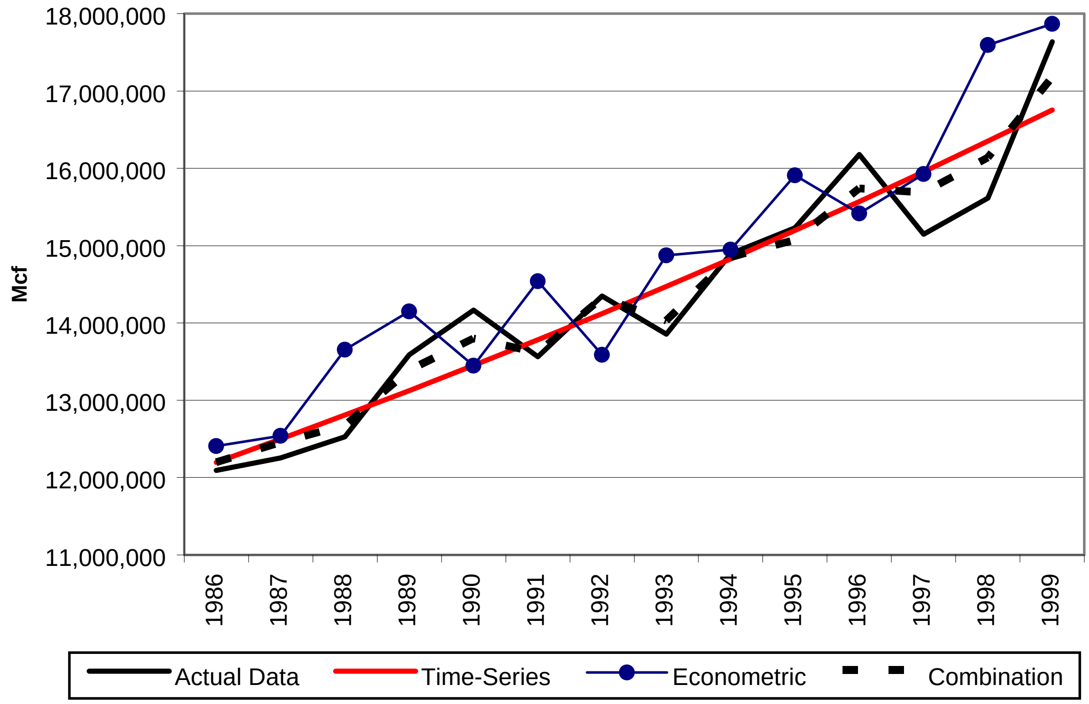

Figure A.3.1: Actual and Predicted Values of Alaska Residential Natural Gas Usage

Figure A.3.2 presents the baseline forecasted values for residential natural gas usage out to the year 2020. The three series plotted represents each of the different forecasting methods: econometric; time series; and combination of forecasts. Based upon the combination of forecasts, baseline residential natural gas usage is estimated to grow at an annual average rate of about 2.5 percent. This is somewhat less than the 1987-1999 average of 3.1 percent. However, the 1998-1999 annual growth of some 13 percent keeps the overall period annual averages high. Excluding this year, residential natural gas usage was over the 1987-1988 period was approximately 2.3 percent. Thus, the baseline forecast annual average growth rate of 2.5 percent is much more in keeping with overall recent historic trends, adjusting for the significant growth in the 1998-1999 time period.

The baseline econometric model used to forecast residential natural gas usage growth is based upon a simple five year trend of existing several explanatory variables. Prices were assumed to be constant in real dollars over the baseline forecast period. Obviously, changes in the expected growth rates of any of the independent variables will have implications for future residential natural gas usage levels. Sensitivities to these underlying assumptions, and the resulting changes in natural gas usage, have been provided in Section 5 of this report. Table A.3.3 presents the actual and baseline residential usage forecast.

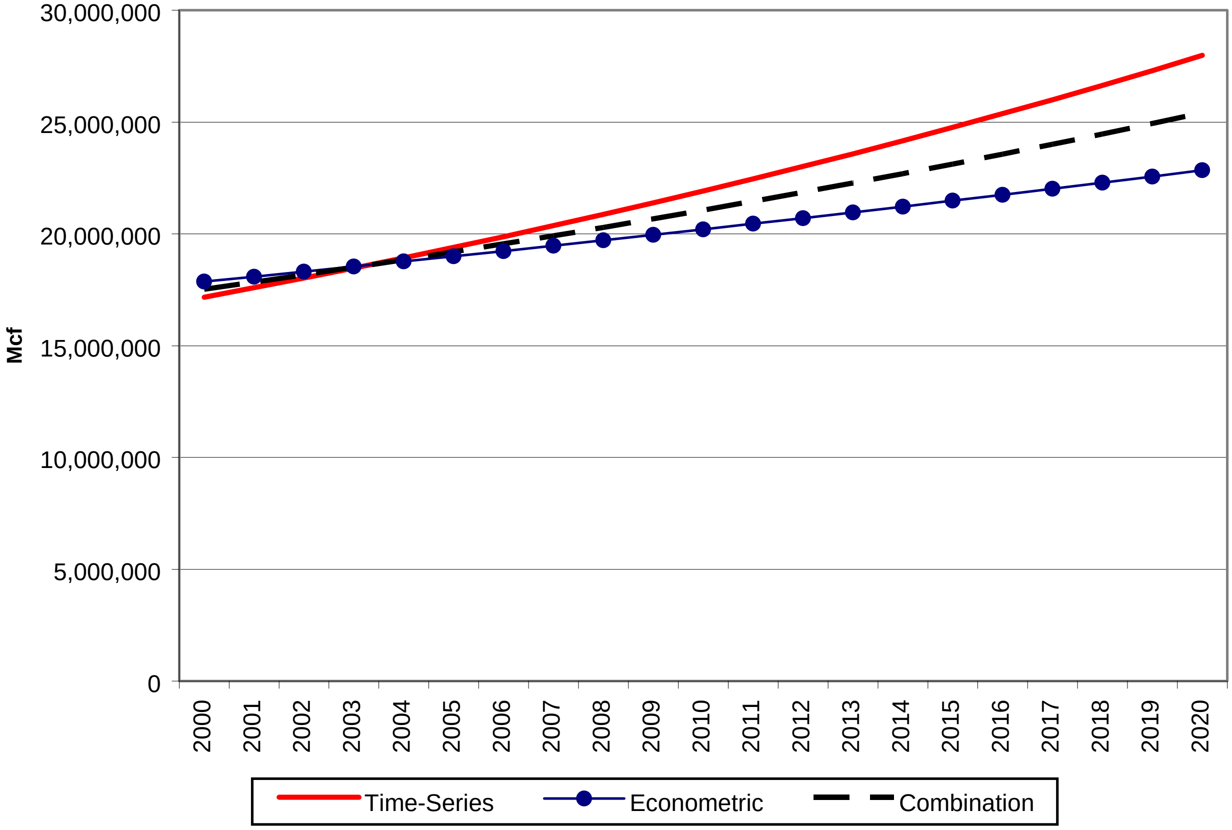

Figure A.3.2: Forecasts of Alaska Residential Natural Gas Usage

Table A.3.3: Alaska Residential Natural Gas Usage: Actual and Baseline Forecast (Mcf)

Date	Actual Data	Predicted Time-Series	Predicted Econometric	Predicted Combination
1986	12,090,998	12,198,225		12,198,225
1987	12,256,280	12,499,708	12,406,056	12,452,882
1988	12,529,140	12,808,641	12,540,566	12,674,604
1989	13,588,767	13,125,210	13,655,173	13,390,191
1990	14,164,886	13,449,602	14,151,008	13,800,305
1991	13,561,759	13,782,013	13,445,474	13,613,744
1992	14,349,944	14,122,639	14,537,644	14,330,141
1993	13,857,568	14,471,683	13,585,834	14,028,759
1994	14,895,199	14,829,354	14,873,428	14,851,391
1995	15,230,778	15,195,865	14,947,440	15,071,653
1996	16,179,216	15,571,435	15,908,103	15,739,769
1997	15,146,116	15,956,287	15,415,471	15,685,879
1998	15,616,617	16,350,651	15,926,681	16,138,666
1999	17,633,864	16,754,761	17,594,905	17,174,833
2000	--	17,168,859	17,867,599	17,518,229
2001	--	17,593,192	18,087,424	17,840,308
2002	--	18,028,012	18,310,890	18,169,451
2003	--	18,473,578	18,537,190	18,505,384
2004	--	18,930,157	18,766,257	18,848,207
2005	--	19,398,021	18,998,187	19,198,104
2006	--	19,877,448	19,232,955	19,555,201
2007	--	20,368,724	19,470,649	19,919,686
2008	--	20,872,142	19,711,255	20,291,698
2009	--	21,388,002	19,954,860	20,671,431
2010	--	21,916,612	20,201,450	21,059,031
2011	--	22,458,286	20,451,117	21,454,701
2012	--	23,013,349	20,703,866	21,858,607
2013	--	23,582,129	20,959,711	22,270,920
2014	--	24,164,967	21,218,750	22,691,858
2015	--	24,762,210	21,480,954	23,121,582
2016	--	25,374,215	21,746,434	23,560,325
2017	--	26,001,345	22,015,159	24,008,252
2018	--	26,643,974	22,287,242	24,465,608
2019	--	27,302,487	22,562,653	24,932,570
2020	--	27,977,274	22,841,498	25,409,386

A.3.3: Commercial Natural Gas Demand Models

Table A.3.4 presents the econometric results from the commercial natural gas usage model. Modeling commercial usage is difficult because this class, unlike residential customers, tends to be very heterogeneous. The econometric model of commercial natural gas usage is based upon prices, income, heating degree days, and the number of customers. The overall fit of the model, as represented in the adjusted R-square value, is relatively good.

Table A.3.4: Econometric Results from Commercial Natural Gas Demand Model

Variable	Coefficient	Standard Error	t-Statistic
Intercept	41.8978	20.8635	2.01
Polynomial Price Terms			
Current Period Price	-0.8042	0.3504	-2.29
Lagged Price (t-1)	-0.5361	0.2336	-2.29
Lagged Price (t-2)	-0.2681	0.1168	-2.29
Income (PCI)	0.1453	1.3608	0.11
Heating Degree Days	0.0172	0.2551	0.07
Customers	-2.6406	2.5185	-1.05
Adjusted R^2	0.9122		

The commercial price elasticity of demand is –0.8 for the current period, -0.54 for lag 1, and –0.27 for lag 2. These estimated elasticities indicate a high degree of price responsiveness. All the price elasticities are significant. Income elasticity is estimated to be 0.15, which is also of the correct sign, yet is statistically insignificant. The relationship between commercial usage and number of customer is negative, yet insignificant. The statistical results from the time series model have been presented in Table A.3.5.

Table A.3.5: Time Series Results from Commercial Natural Gas Demand Model

Commercial Time Series: Damped Trend Exponential Smoothing	Parameter	Standard Error	t- Statistic
LEVEL Smoothing Weight	0.999	0.23	4.338
TREND Smoothing Weight	0.001	0.19	0.005
DAMPING Smoothing Weight	0.999	0.05	19.967
R Square	0.785		
Mean Absolute Percent Error	3.891		

Figure A.3.3 presents a graph of the commercial natural gas usage models. Actual, econometric, time series, and combination models have been plotted on the graph.

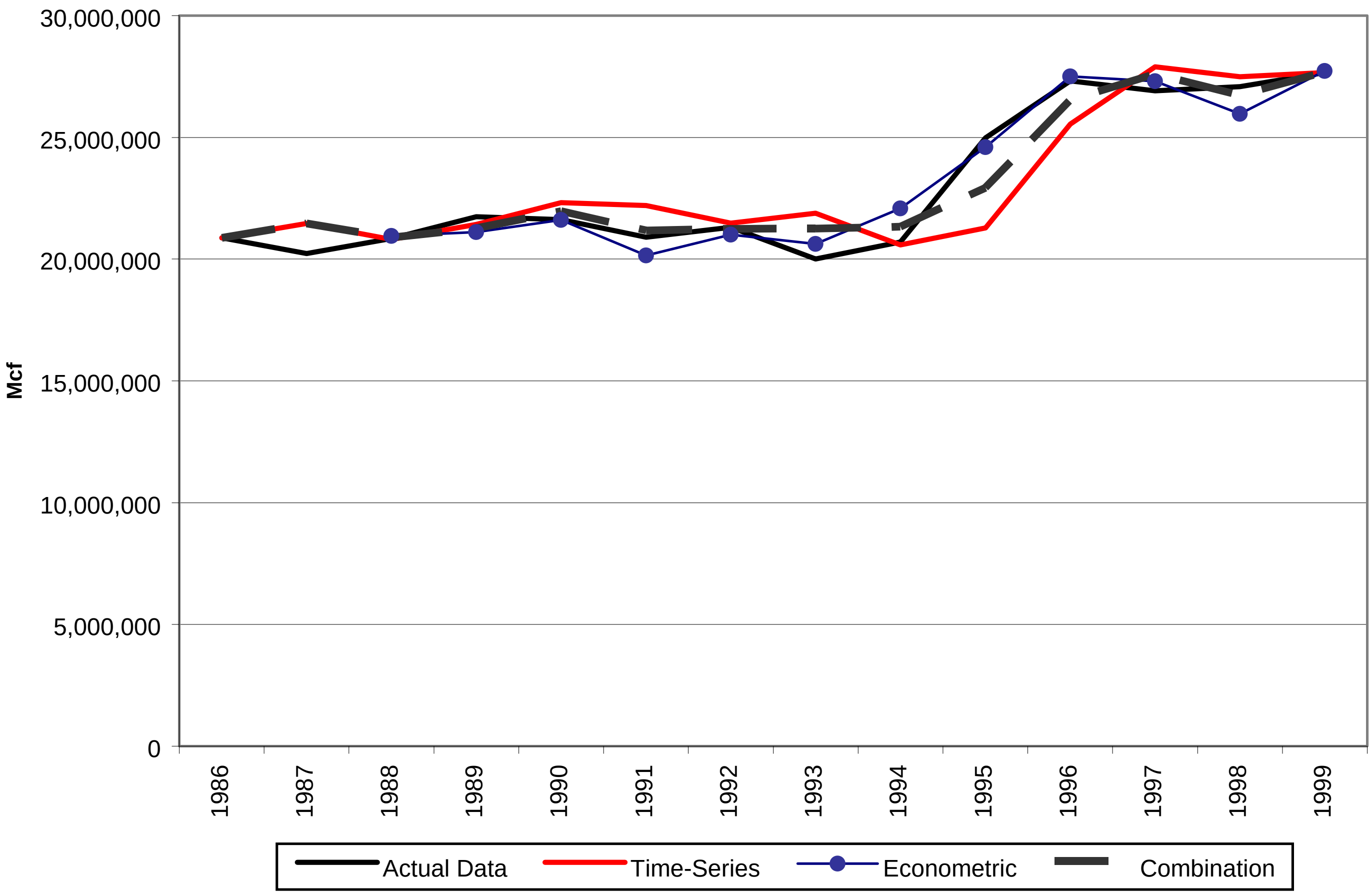

Figure A.3.3: Actual and Predicted Values of Alaska Commercial Natural Gas Usage

Figure A.3.4 plots the results for baseline forecasted commercial natural gas usage from the period 1999 until 2020. The combined model predicts that commercial natural gas usage will take an early dip in 2001, to be followed by some upward growth opportunities. The combination forecast anticipates commercial natural gas usage to grow by an annual average rate of about 1.0 percent through the year 2020. This is below the 1987-1999 average of 2.4 percent.

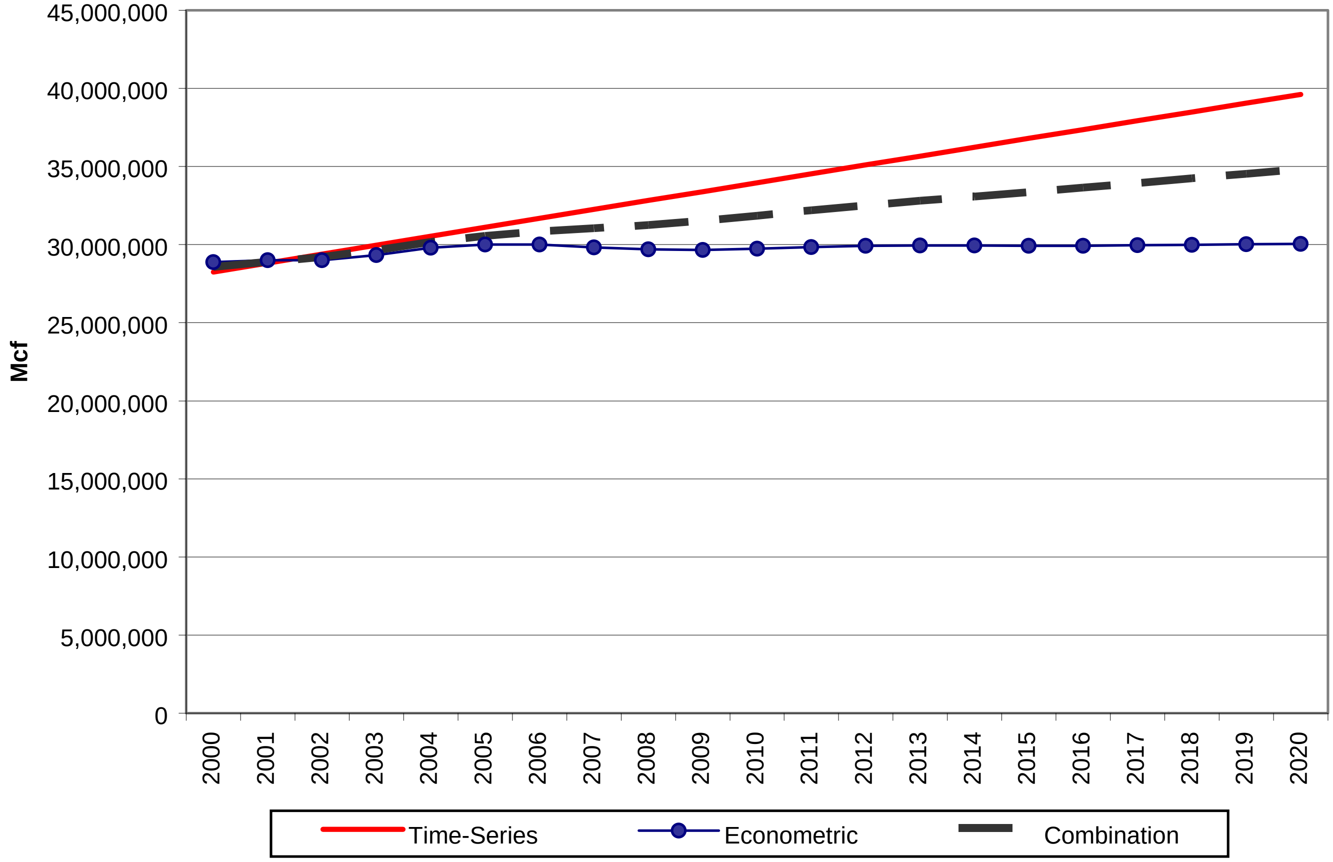

Figure A.3.4: Forecasts of Alaska Commercial Natural Gas Usage

Table A.3.6 presents the actual and baseline commercial usage forecast. Annual average rates of growth for both the historic period, and the forecast period are provided.

Table A.3.6: Alaska Commercial Natural Gas Usage: Actual and Baseline Forecast (Mcf)

Date	Actual Data	Predicted Time-Series	Predicted Econometric	Predicted Combination
1986	20,874,011	20,872,099		20,872,099
1987	20,224,143	21,459,238		21,459,238
1988	20,842,041	20,808,703	20,952,886	20,880,795
1989	21,738,412	21,424,696	21,111,727	21,268,211
1990	21,621,850	22,320,431	21,608,730	21,964,580
1991	20,897,429	22,203,516	20,147,636	21,175,576
1992	21,299,274	21,477,732	20,996,129	21,236,931
1993	20,002,655	21,877,606	20,617,698	21,247,652
1994	20,697,859	20,580,149	22,079,885	21,330,017
1995	24,978,977	21,272,817	24,597,540	22,935,179
1996	27,314,942	25,553,385	27,507,854	26,530,620
1997	26,908,231	27,892,388	27,310,569	27,601,479
1998	27,078,631	27,486,776	25,963,527	26,725,151
1999	27,667,159	27,655,530	27,727,955	27,691,742
2000	--	28,242,988	28,890,145	28,566,567
2001	--	28,818,167	28,999,111	28,908,639
2002	--	29,392,686	29,012,758	29,202,722
2003	--	29,966,545	29,338,263	29,652,404
2004	--	30,539,746	29,796,778	30,168,262
2005	--	31,112,288	30,016,438	30,564,363
2006	--	31,684,173	29,997,933	30,841,053
2007	--	32,255,402	29,832,200	31,043,801
2008	--	32,825,975	29,696,295	31,261,135
2009	--	33,395,893	29,666,724	31,531,308
2010	--	33,965,156	29,738,479	31,851,818
2011	--	34,533,766	29,843,132	32,188,449
2012	--	35,101,723	29,920,323	32,511,023
2013	--	35,669,028	29,946,149	32,807,588
2014	--	36,235,682	29,937,088	33,086,385
2015	--	36,801,685	29,923,989	33,362,837
2016	--	37,367,038	29,929,179	33,648,108
2017	--	37,931,743	29,955,787	33,943,765
2018	--	38,495,799	29,993,163	34,244,481
2019	--	39,059,207	30,028,044	34,543,626
2020	--	39,621,969	30,053,513	34,837,741

A.3.4: Industrial Natural Gas Demand Model

Table A.3.7 presents the results for the econometric industrial natural gas demand model. Like commercial models, these models are difficult to estimate given the wide range of heterogeneity of the firms within this customer class. In fact, the problem of aggregation is probably most exaggerated for industrial customers as opposed to any other class. Nevertheless, all of the explanatory variables, with the exception of customer growth, have tended to take the appropriate values and signs for the industrial model. These parameter estimates, however, are statistically insignificant. The results for the time series model have been presented in Figure A.3.8.

Table A.3.7: Econometric Results from Industrial Natural Gas Demand Model

Variable	Coefficient	Standard Error	t-Statistic
Intercept	17.1259	1.4676	11.67
Price	-0.1178	0.2669	-0.44
Income (Manufacturing GSP)	0.1901	0.1878	1.01
Customers	-0.1665	0.1696	-0.98
Adjusted R^2	0.251		

Table A.3.8: Time Series Results from Industrial Natural Gas Demand Model

Industrial Natural Gas Demand Linear Trend	Parameter	Standard Error	t- Statistic
Intercept	65,380,932	3,683,266	17.751
Linear Trend	684,265	432,578	1.582
R Square	0.173		
Mean Absolute Percent Error	6.8		

Figure A.3.5 graphs the results from each of the models developed and compared the results to the actual values. Figure A.3.6 presents our forecasted results.

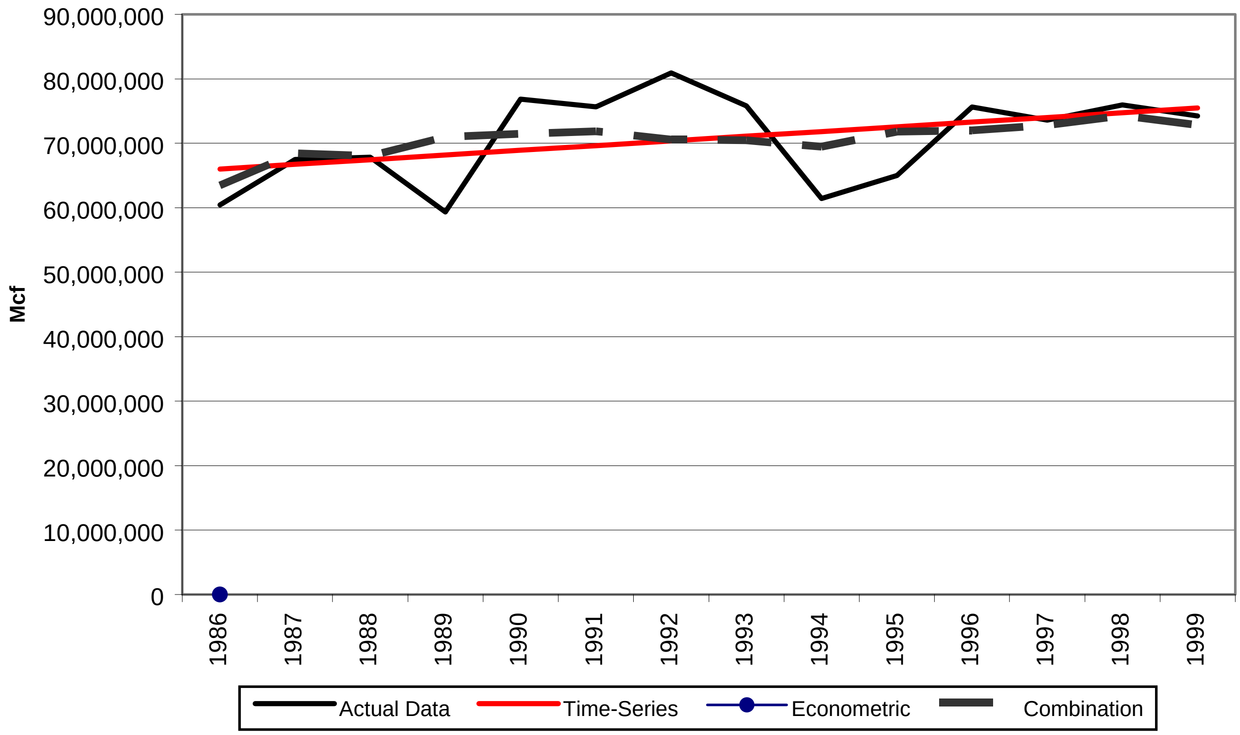

Figure A.3.5: Actual and Predicted Values of Alaska Industrial Natural Gas Usage

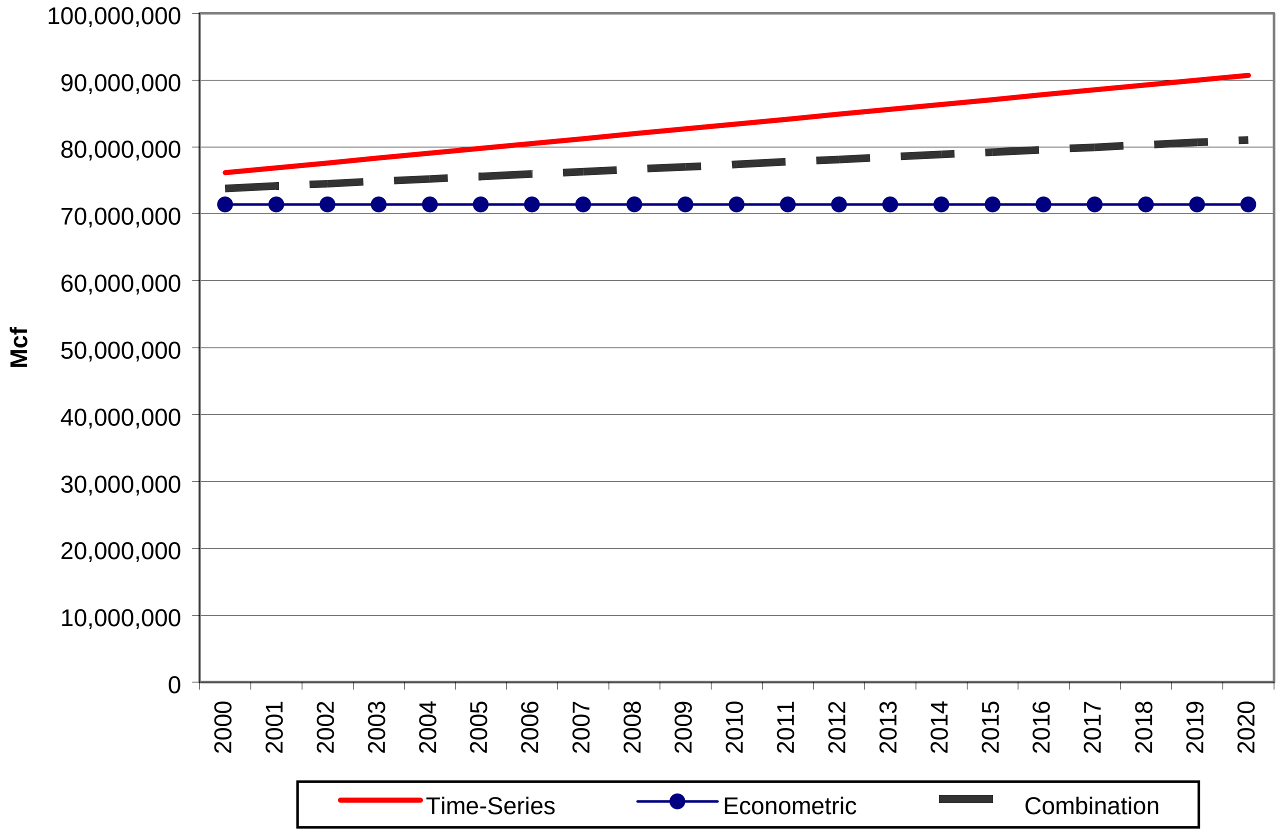

Figure A.3.6: Forecasts of Alaska Industrial Natural Gas Usage

Table A.3.9 presents the actual and baseline industrial usage forecast. Annual average rates of growth for both the historic period, and the forecast period are provided.

Table A.3.9: Alaska Industrial Natural Gas Usage: Actual and Baseline Forecast (Mcf)

Date	Actual Data	Predicted Time-Series	Predicted Econometric	Predicted Combination
1986	60,438,785	65,983,516	60,953,186	63,468,351
1987	67,467,489	66,711,763	70,090,074	68,400,918
1988	67,804,860	67,440,010	68,568,283	68,004,146
1989	59,341,410	68,168,256	73,723,646	70,945,951
1990	76,849,333	68,896,503	73,991,984	71,444,243
1991	75,637,177	69,624,750	74,064,575	71,844,662
1992	80,937,950	70,352,997	70,766,558	70,559,778
1993	75,794,979	71,081,244	69,802,135	70,441,689
1994	61,404,028	71,809,491	67,148,789	69,479,140
1995	64,977,342	72,537,737	71,056,370	71,797,053
1996	75,616,070	73,265,984	70,741,268	72,003,626
1997	73,599,299	73,994,231	71,538,235	72,766,233
1998	75,946,906	74,722,478	73,864,793	74,293,635
1999	74,224,056	75,450,725	70,231,772	72,841,248
2000	--	76,178,972	70,298,379	73,238,676
2001	--	76,907,218	70,365,044	73,636,131
2002	--	77,635,465	70,431,784	74,033,625
2003	--	78,363,712	70,498,588	74,431,150
2004	--	79,091,959	70,565,442	74,828,701
2005	--	79,820,206	70,632,373	75,226,290
2006	--	80,548,453	70,699,354	75,623,904
2007	--	81,276,699	70,766,412	76,021,556
2008	--	82,004,946	70,833,520	76,419,233
2009	--	82,733,193	70,900,705	76,816,949
2010	--	83,461,440	70,967,941	77,214,690
2011	--	84,189,687	71,035,253	77,612,470
2012	--	84,917,933	71,102,616	78,010,275
2013	--	85,646,180	71,170,057	78,408,118
2014	--	86,374,427	71,237,547	78,805,987
2015	--	87,102,674	71,305,116	79,203,895
2016	--	87,830,921	71,372,748	79,601,835
2017	--	88,559,168	71,440,431	79,999,800
2018	--	89,287,414	71,508,192	80,397,803
2019	--	90,015,661	71,576,003	80,795,832
2020	--	90,743,908	71,643,893	81,193,900

A.3.5: Electric Utility Natural Gas Demand Model

The baseline forecast for electric utility natural gas demand proceeded differently than the other natural gas customer classes in Alaska given the limited number of utility power generation units, and their limited number of existing fuel switching opportunities. The analysis proceeded along two lines.

First, utilities demand natural gas to fire their generators to serve their electrical load. In order to determine the amount of natural gas electric utilities would demand, a general forecast of electricity usage in Alaska needs to be developed. A generalized time series model of Alaska electricity usage was developed to determine longer run power generation trends.

Second, a trend analysis of natural gas fuel shares in the Alaska power generation market was developed as an indicator of how much natural gas fired power generation would be used to meet new load requirements. The forecast of overall power generation needs, was then multiplied by the fuel mix trend to determine overall electric utility generation from natural gas. Finally, the gas consumption requirement was estimated by multiplying the forecast for generation from gas by the 5-year moving average gas conversion rate (ratio of gas consumption to power generation from gas) consumption requirements. Figure A.3.7 presents the forecast of those natural gas requirements for Alaska electric utility power generation.

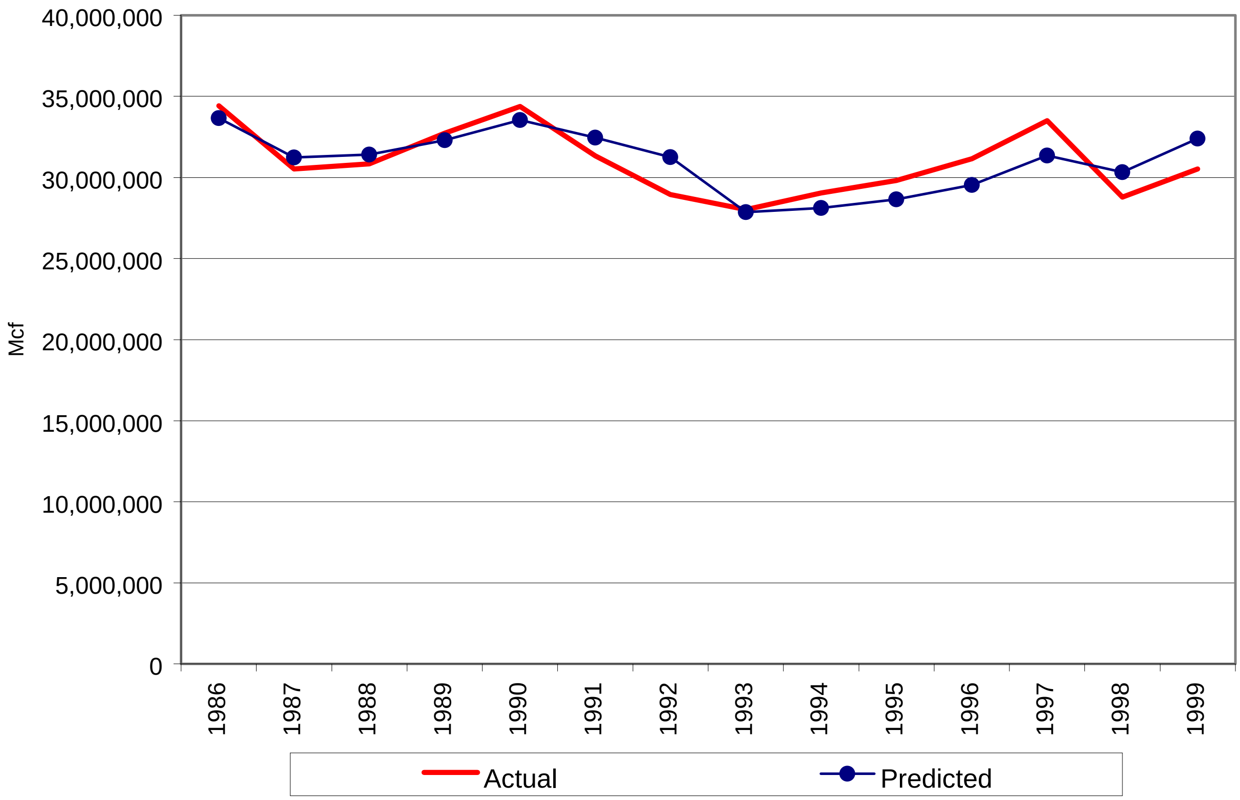

Figure A.3.7: Actual and Predicted Values of Alaska Electric Utility Natural Gas Usage

Figure A.3.8 presents a graph of the baseline electric utility forecast while Table A.3.10 presents the actual and our baseline electric utility natural gas usage forecast levels. Annual average rates of growth for both the historic period, and the forecast period are provided.

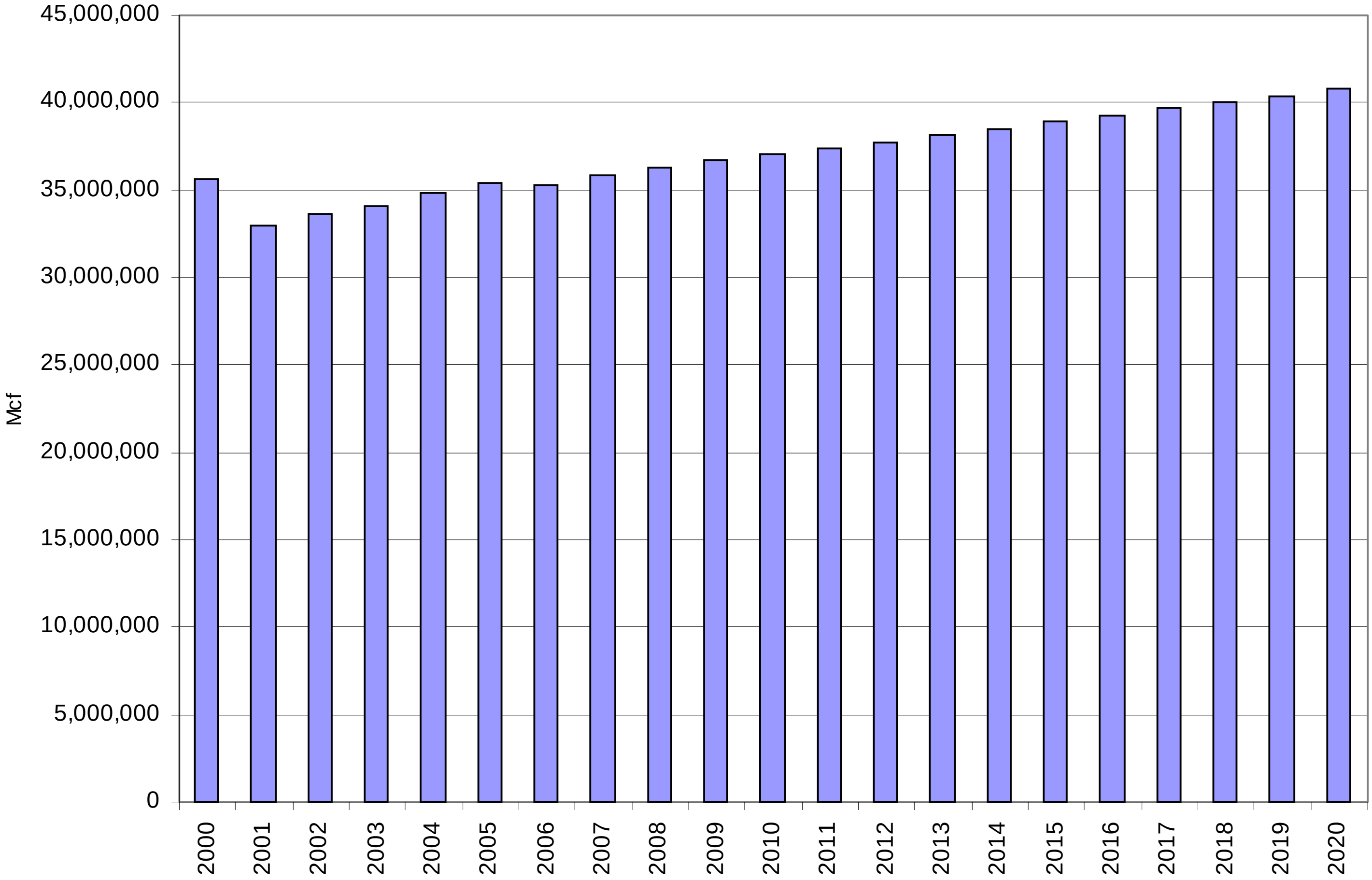

Figure A.3.8: Forecasts of Alaska Electric Utility Natural Gas Usage

Table A.3.10: Alaska Electric Utility Natural Gas Usage: Actual and Baseline Forecast (Mcf)

Date	Actual Data	Predicted Time-Series
1986	34,409,000	33,670,793
1987	30,530,000	31,234,619
1988	30,841,000	31,418,047
1989	32,746,000	32,312,018
1990	34,366,142	33,549,084
1991	31,329,758	32,470,899
1992	28,953,390	31,259,209
1993	28,024,737	27,867,045
1994	29,047,703	28,129,752
1995	29,808,627	28,661,334
1996	31,154,273	29,541,429
1997	33,509,748	31,362,521
1998	28,784,955	30,332,479
1999	30,527,841	32,409,397
2000	--	35,656,886
2001	--	32,949,652
2002	--	33,655,948
2003	--	34,119,758
2004	--	34,899,977
2005	--	35,406,497
2006	--	35,330,693
2007	--	35,813,699
2008	--	36,248,792
2009	--	36,677,751
2010	--	37,031,714
2011	--	37,353,364
2012	--	37,759,602
2013	--	38,149,476
2014	--	38,529,726
2015	--	38,899,627
2016	--	39,272,923
2017	--	39,657,179
2018	--	40,036,768
2019	--	40,414,176
2020	--	40,790,982

A.3.6: Total Natural Gas Usage

The summation of the baseline forecasts for each customer class can be used to analyze total in-state demand until 2020 under business as usual conditions. The total baseline forecast is developed from the individual customer class combination forecasts. Total in-state, baseline usage, is presented in Table A.3.11, while Figure A.3.9 presents a graphical representation of annual baseline usage levels.

In-state baseline forecasted natural gas usage over the forecast period will grow by 27 Bcf. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. Sensitivities to the overall baseline forecast, and total forecasted use by the year 2020, are explored in the baseline sensitivities section of the report (Chapter 5).

Table A.3.11: Total In-State Baseline Demand Forecast

Date	Actual Data	Baseline
1986	127,812,794	130,209,467
1987	130,477,912	133,547,658
1988	132,017,041	132,977,591
1989	127,414,589	137,916,372
1990	147,002,211	140,758,213
1991	141,426,123	139,104,881
1992	145,540,558	137,386,059
1993	137,679,939	133,585,145
1994	126,044,789	133,790,300
1995	134,995,724	138,465,219
1996	150,264,501	143,815,443
1997	149,163,394	147,416,112
1998	147,427,109	147,489,931
1999	150,052,920	150,117,221
2000	--	154,980,358
2001	--	153,334,730
2002	--	155,061,745
2003	--	156,708,696
2004	--	158,745,146
2005	--	160,395,253
2006	--	161,350,851
2007	--	162,798,743
2008	--	164,220,859
2009	--	165,697,439
2010	--	167,157,253
2011	--	168,608,985
2012	--	170,139,507
2013	--	171,636,103
2014	--	173,113,957
2015	--	174,587,941
2016	--	176,083,191
2017	--	177,608,996
2018	--	179,144,660
2019	--	180,686,203
2020	--	182,232,010

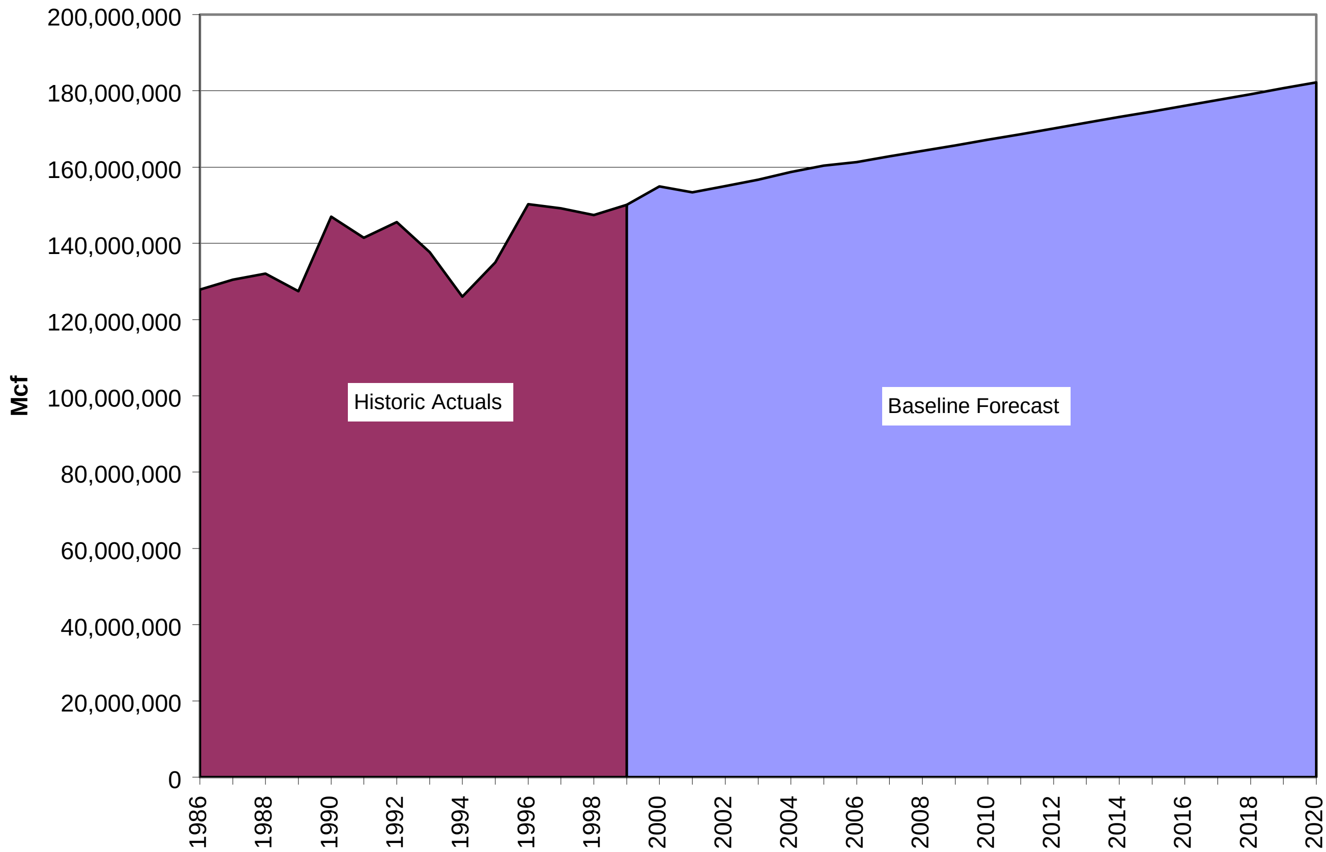

Figure A.3.9: Total In-State Natural Gas Usage – Baseline Forecast