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Intermountain Gas Company
Integrated Resource Plan
Executive Summary

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and anticipated new electric power plants, all rely on natural gas to provide an economic, efficient, environmentally friendly and most comfortable form of heating energy. Intermountain Gas Company endorses and encourages the wise and efficient use of energy in general and, in particular, natural gas for high efficient uses in Idaho and Intermountain's service area (see Pages 48-50). Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of this planning process. The customer demand forecast and resource decision making process is ongoing. This Integrated Resource Plan document represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions, as conditions will change over the planning horizon impacting areas covered by this Plan. Rather, this document is meant to describe the currently anticipated conditions over the five-year planning horizon, the anticipated resource selections and the process for making those resource decisions. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

Backdrop

Intermountain Gas Company ("Intermountain") is the sole distributor of natural gas in Southern Idaho. Its service area extends across the entire breadth of Southern Idaho, an area of 50,000 square miles, with a population of approximately 900,000. During fiscal year 2001, Intermountain served an average of 219,000 customers in 74 communities through a system of 8,503 miles of transmission, distribution and service lines. Over 321 miles of distribution and service lines were added during fiscal 2001 to accommodate new customer additions and maintain service for Intermountain's growing customer base.

The economy of Intermountain's service area is based primarily on agriculture and related industries. Major crops are potatoes and sugar beets. Major agriculture-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and services to two major markets: the residential/commercial market and the industrial market. During the first quarter of fiscal year 2002, an average of 203,000 residential and 25,000 commercial customers used natural gas primarily for space and water heating, compared to an average of 195,000 residential and 24,000 commercial customers in the first quarter fiscal year 2001. This equates to an increase in average residential and commercial customers of 5%.

Intermountain's industrial customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications, as well as feedstock in the production of chemical fertilizers. Industrial demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. Fifty percent (50%) of the throughput on Intermountain's system during fiscal 2001 was attributable to industrial sales and transportation.

Intermountain's peak day loads (throughput during the projected coldest winter day) are growing at a manageable rate. The growth in Intermountain's projected peak day load is attributable to two factors: 1) growth in Intermountain's customer base, primarily residential and commercial, and 2) production related growth occurring in Intermountain's industrial firm transportation market which impacts Intermountain's distribution system while not impacting the need for additional interstate pipeline capacity (See Service Options, Page 21).

The customer growth forecast[1] was analyzed and forecast not only from a total company perspective but also by specific geographic regions within Intermountain's service territory. The regions were selected based upon the anticipated or known need for system upgrades within each specific region. The regions, as more fully delineated later in this document, consist of The Idaho Falls Lateral Region, The Sun Valley Lateral Region, The Canyon County Region and the "All Other" Region.

Peak day sendout studies and load duration curves were developed under design weather conditions (see page 29) to determine the magnitude and timing of future deficiencies in firm peak day delivery capability from both a total company interstate mainline perspective, as well as within each specific geographic region. Residential, commercial and industrial customer peak day sendout was matched against available resources to determine which combination of new resources would be needed to meet Intermountain's future peak day delivery requirements at the best possible cost.

Forecast Peak Day Sendout

Total Company

Residential, commercial and industrial peak day load growth on Intermountain's system under design conditions is forecast over the five-year period to grow at an average annual rate of 4%. The table below summarizes the forecast for peak day sendout under the "baseline" customer growth assumption.

LOAD DURATION CURVE - TOTAL COMPANY DESIGN BASELINE
(Volumes in Therms)

	NWP Firm Transport Capacity	Peak Day Sendout			Incremental Peak Day Sendout		
		Core Market	Industrial Firm CD	Total	Core Market	Industrial Firm CD[1]	Total
FY03	1,863,300	3,180,540	408,680	3,589,220			
FY04	1,863,300	3,323,630	408,680	3,732,310	143,090	0	143,090
FY05	1,863,300	3,474,790	408,680	3,883,470	151,160	0	151,160
FY06	1,863,300	3,629,920	408,680	4,038,600	155,130	0	155,130
FY07	1,863,300	3,789,040	408,680	4,197,720	159,120	0	159,120

[1] Future growth in transport CD is limited to T-4, which does not affect Intermountain's interstate pipeline capacity requirements.

The above table highlights the fact that growth in the peak day is commensurate with the growth projected to occur in Intermountain's residential and small commercial customer markets.

Existing Resources:

Intermountain's existing firm delivery capability on the peak day is made up of the resources shown on the following page.

[1] Multiple residential and commercial customer growth scenarios were developed. Each scenario ("baseline", "high" and "low") was driven by the potential for varying outcomes of Idaho's economy (See Pages 9-18.)

PEAK DAY FIRM DELIVERY CAPABILITY (Volumes in Therms)	FY03 & FY04	FY05 - FY07
Maximum Daily Storage Withdrawals:		
Nampa LNG	600,000	600,000
Plymouth LS	720,000	720,000
Jackson Prairie SGS	150,000	303,370
Total Storage	1,470,000	1,623,370
Maximum Deliverability (NWP)	1,863,300	1,863,300
Total Peak Day Deliverability	3,333,300	3,486,670

When forecasted peak day sendout is matched against existing resources, a peak day delivery deficit occurs during January 2003 and increases at a rate of 29% as depicted on the following table.

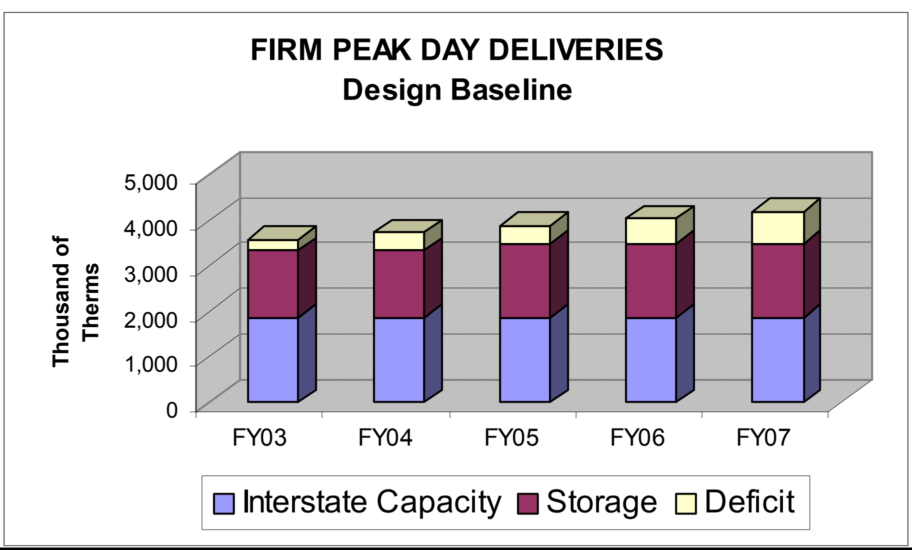
FIRM DELIVERY DEFICIT - TOTAL COMPANY DESIGN BASELINE

(Volumes in Therms)

	FY03	FY04	FY05	FY06	FY07
Peak Day Deficit [1]	255,920	399,010	396,800	551,930	711,050
Total Winter Deficit[2]	1,562,397	2,416,760	3,365,018	4,394,645	5,488,932
Days Requiring Additional Resources	63	75	93	97	109

[1]Peaking storage increases by 150,000 therms per day in FY05 which reduces the deficit thereafter.

[2]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.



As shown in the above table, because Intermountain's storage gas has been dispatched or "rationed" around the peak day in order to meet the higher demand days first, a deficit of firm capacity begins to occur "around" the peak day during the "shoulder months" under design conditions beginning in the winter of 2003.

Firm transportation capacity will be secured by Intermountain during these projected deficit shoulder periods. Intermountain, together with its gas procurement agent, is performing an extensive evaluation of the most advantageous way to eliminate this deficit taking into consideration first of all firm delivery capability to Intermountain's core market together with economic efficiency. The projected deficits in firm deliverability will be eliminated in a timely manner through one or more means including, but not limited to, 1) long-term firm capacity release and/or segmentation, 2) city gate deliverable gas supply, 3) storage together with related mainline rights and, 4) call back opportunities.

Regional Studies

As mentioned above, certain geographic regions within Intermountain's service territory were analyzed based upon the anticipated or known need for distribution system upgrades within each specific region. Not unlike the total company interstate mainline perspective, the projected peak day sendout for each region was measured against the known distribution capacity available to serve that region. In addition to the firm delivery requirements for Intermountain's residential and commercial customers, the needs of those industrial customers contracting for firm distribution only transportation service (Intermountain's "T-4" customers) were also included as part of these regional studies. A wide array of alternatives were evaluated in determining the potential way to best meet the projected deficits in the various regions within Intermountain Gas Company (see "Non-Traditional Resource Options" - Page 44). Additionally, each region is analyzed within the framework of the Company's Distribution System Model (See Page 46).

Idaho Falls Lateral Region

The Idaho Falls Lateral ("IFL") is 104 miles in length and serves a number of cities between Pocatello in the south to St. Anthony in the north (See Map on Page 8). The customers served off the IFL represent a diverse base of residential, commercial and large industrial customers. The residential, commercial and industrial load served off the IFL represents approximately 14% of the total company customers and 18% of the company's total winter sendout during the winter of 2001-2002.

When forecasted peak day sendout on the IFL is matched against the existing peak day distribution capacity (690,000 therms), a peak day delivery deficit occurs during 2005 and increases at levels shown on the following tables:

LOAD DURATON CURVE - IDAHO FALLS DESIGN BASELINE
(Volumes in Therms)

	Existing Distribution Transport Capacity	Peak Day Sendout			Incremental Peak Day Sendout		
		Core Market	Industrial Firm CD[1]	Total	Core Market	Industrial Firm CD[2]	Total
FY03	690,000	443,630	214,630	658,630			
FY04	690,000	464,610	214,630	679,240	20,980	0	20,980
FY05	690,000	486,640	250,630	737,270	22,030	36,000	58,030
FY06	690,000	509,420	250,630	760,050	22,780	0	22,780
FY07	690,000	534,040	265,630	799,670	24,620	15,000	39,620

[1]Existing firm contract demand includes T-1, T-2 and T-4 requirements.
[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

FIRM DELIVERY DEFICIT - IDAHO FALLS DESIGN BASELINE
(Volumes in Therms)

	FY03	FY04	FY05	FY06	FY07
Peak Day Deficit[1]	0	0	47,272	70,055	109,671
Total Winter Deficit[2]	0	0	65,091	130,068	266,275
Days Requiring Additional Capacity	0	0	2	3	4

[1]Equal to the total winter sendout in excess of distribution capacity.

The industrial customer base on the IFL is unique in that several of these customers have the potential and ability to mitigate peak day consumption by switching to fuel oil during extreme cold temperatures. Although these customers prefer using natural gas to any other fuel alternative, Intermountain believes that small, short duration peak day distribution delivery deficits in the future can be eliminated or at least mitigated by working with these customers to facilitate the use of fuel oil at these customer's facilities. However, the projected delivery deficits are of such magnitude that "looping" of the existing system is warranted adding the necessary firm delivery capability to that area.

Sun Valley Lateral Region

The residential, commercial and industrial load served off the Sun Valley Lateral ("SVL") represents approximately 4% of the total company customers and 3% of the company's total winter sendout during the winter of 2001-2002.

When forecasted peak day sendout on the Sun Valley Lateral ("SVL") is matched against the existing peak day distribution capacity (120,000 therms), a peak day delivery deficit occurs during 2003 and increases at the levels shown on the following tables:

LOAD DURATON CURVE - SUN VALLEY DESIGN BASELINE
(Volumes in Therms)

	Existing Distribution Transport Capacity	Peak Day Sendout Core Market	Peak Day Sendout Industrial Firm CD[1]	Peak Day Sendout Total	Incremental Peak Day Sendout Core Market	Incremental Peak Day Sendout Industrial Firm CD[2]	Incremental Peak Day Sendout Total
FY03	120,000	122,930	5,680	128,610			
FY04	120,000	127,070	5,680	132,750	4,140	0	4,140
FY05	120,000	131,180	5,680	136,860	4,110	0	4,110
FY06	120,000	135,360	5,680	141,040	4,180	0	4,180
FY07	120,000	139,590	5,680	145,270	4,230	0	4,230

[1]Existing firm contract demand includes T-1, T-2 and T-4 requirements.
[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

FIRM DELIVERY DEFICIT - SUN VALLEY DESIGN BASELINE
(Volumes in Therms)

	FY03	FY04	FY05	FY06	FY07
Peak Day Deficit[1]	8,611	12,749	16,860	21,037	25,269
Total Winter Deficit[2]	12,068	20,169	27,504	41,822	56,005
Days Requiring Additional Capacity	2	2	3	3	4

[1]Equal to the total winter sendout in excess of distribution capacity.

As can be seen from the above table, growth along the SVL warrants an upgrade to the existing pipeline system. The tourism industry driven industrial load on the SVL is limited in size and does not currently have the capability to switch to alternative fuels as a means of mitigating peak day sendout. Again, a wide array of alternatives were evaluated in determining the potential ways to best meet the projected deficits. Intermountain plans to increase the delivery capability and ultimate capacity on the SVL through a series of cost effective system upgrades to be performed over the next several years.

Canyon County Region

The residential, commercial and industrial load served off the Canyon County Lateral ("CCL") represented approximately 12% of the total company customers and 14% of the company's total winter sendout during the winter of 2001-2002.

When forecasted peak day sendout on the Canyon County Lateral CCL is matched against the existing peak day distribution capacity (600,000 therms), a peak day delivery deficit occurs during 2006 and increases at the levels shown on the following tables:

LOAD DURATON CURVE - CANYON COUNTY DESIGN BASELINE
(Volumes in Therms)

	Existing Distribution Transport Capacity	Peak Day Sendout			Incremental Peak Day Sendout		
		Core Market	Industrial Firm CD[1]	Total	Core Market	Industrial Firm CD[2]	Total
FY03	600,000	412,880	121,130	534,010			
FY04	600,000	446,720	121,130	567,850	33,840	0	33,840
FY05	600,000	466,430	121,130	587,560	19,710	0	19,710
FY06	600,000	492,400	121,130	613,530	25,970	0	25,970
FY07	600,000	519,010	121,130	640,140	26,610	0	26,610

[1]Existing firm contract demand includes T-1, T-2 and T-4 requirements.
[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

FIRM DELIVERY DEFICIT - CANYON COUNTY DESIGN BASELINE
(Volumes in Therms)

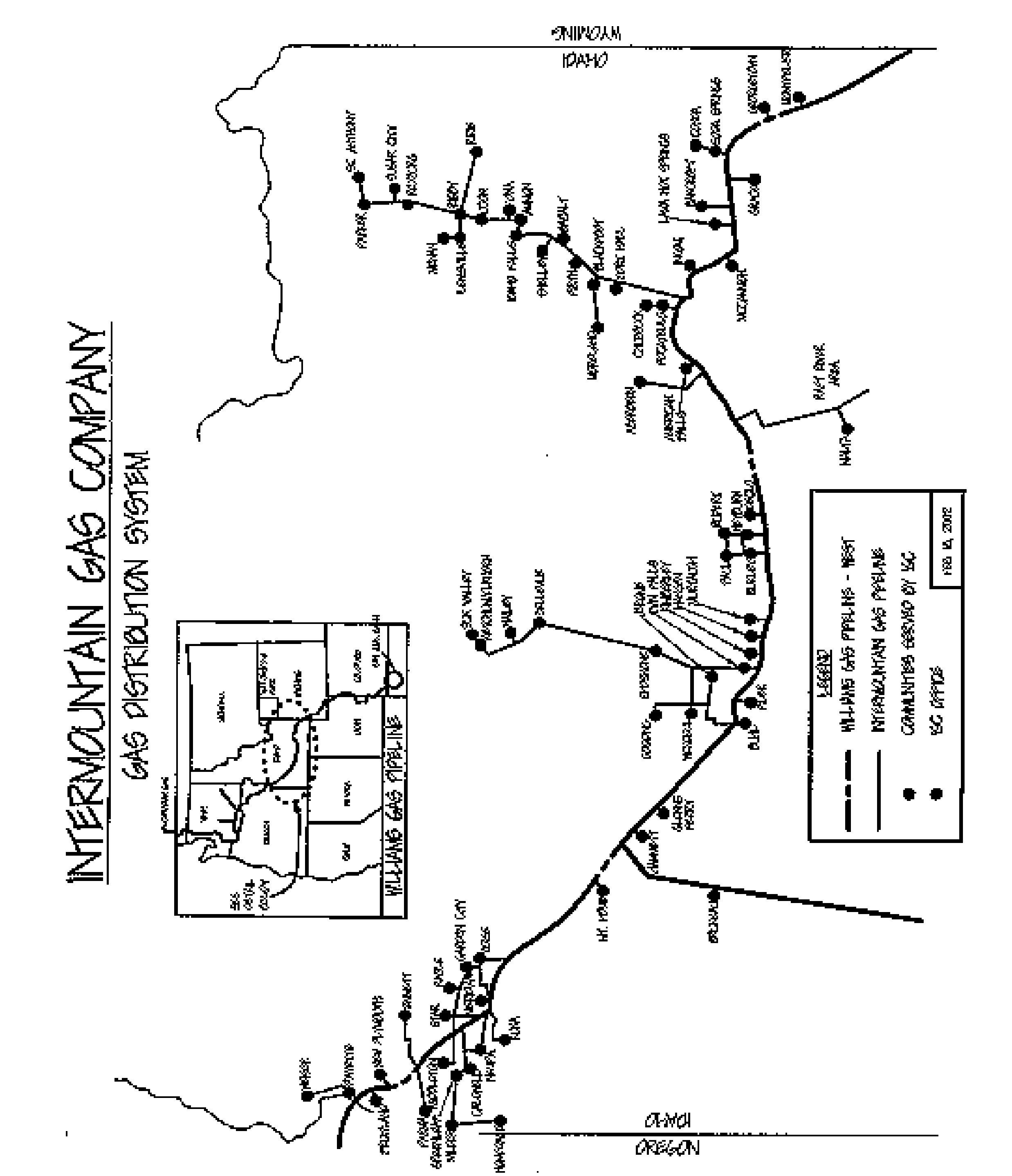
	FY03	FY04	FY05	FY06	FY07
Peak Day Deficit[1]	0	0	0	13,531	40,138
Total Winter Deficit[2]	0	0	0	13,531	58,540
Days Requiring Additional Capacity	0	0	0	1	2

[1]Equal to the total winter sendout in excess of distribution capacity.

While diverse in nature, the industrial customer base served by CCL does not currently have the capability to switch to alternative fuels as a means of mitigating peak day sendout and Intermountain is currently exploring optional means of enhancing the distribution capability on this Lateral. Intermountain is also awaiting the outcome of a planned natural gas fired electric generation plant in the Canyon County Region as the construction of this facility can potentially provide synergies to the design of Intermountain's distribution facilities in that region.

Summary

Residential, commercial and industrial customer growth and its consequent impact on Intermountain's distribution system was analyzed using design weather conditions under various projected outcomes of Idaho's economy. Peak day sendout under each of these customer growth scenarios were measured against the available natural gas delivery systems to project the magnitude and timing of delivery deficits, both from a total company perspective as well as a regional perspective. The resources brought to bear to meet these projected deficits were analyzed within a framework of options, both traditional and non-traditional, to help determine the most cost-effective means available to manage these deficits. In utilizing these various options, Intermountain's core market and firm transportation customers will continue to rely on uninterrupted firm service both now and in the years to come.


INTERMOUNTAIN GAS COMPANY
GAS DISTRIBUTION SYSTEM
WYOMING
IDAHO
OREGON
LEGEND
WILLIAMS GAS PIPELINE - WEST
INTERMOUNTAIN GAS PIPELINE
COMMUNITIES SERVED BY IGC
IGC OFFICES
WILLIAMS GAS PIPELINE

RESIDENTIAL AND COMMERCIAL CUSTOMER GROWTH FORECAST

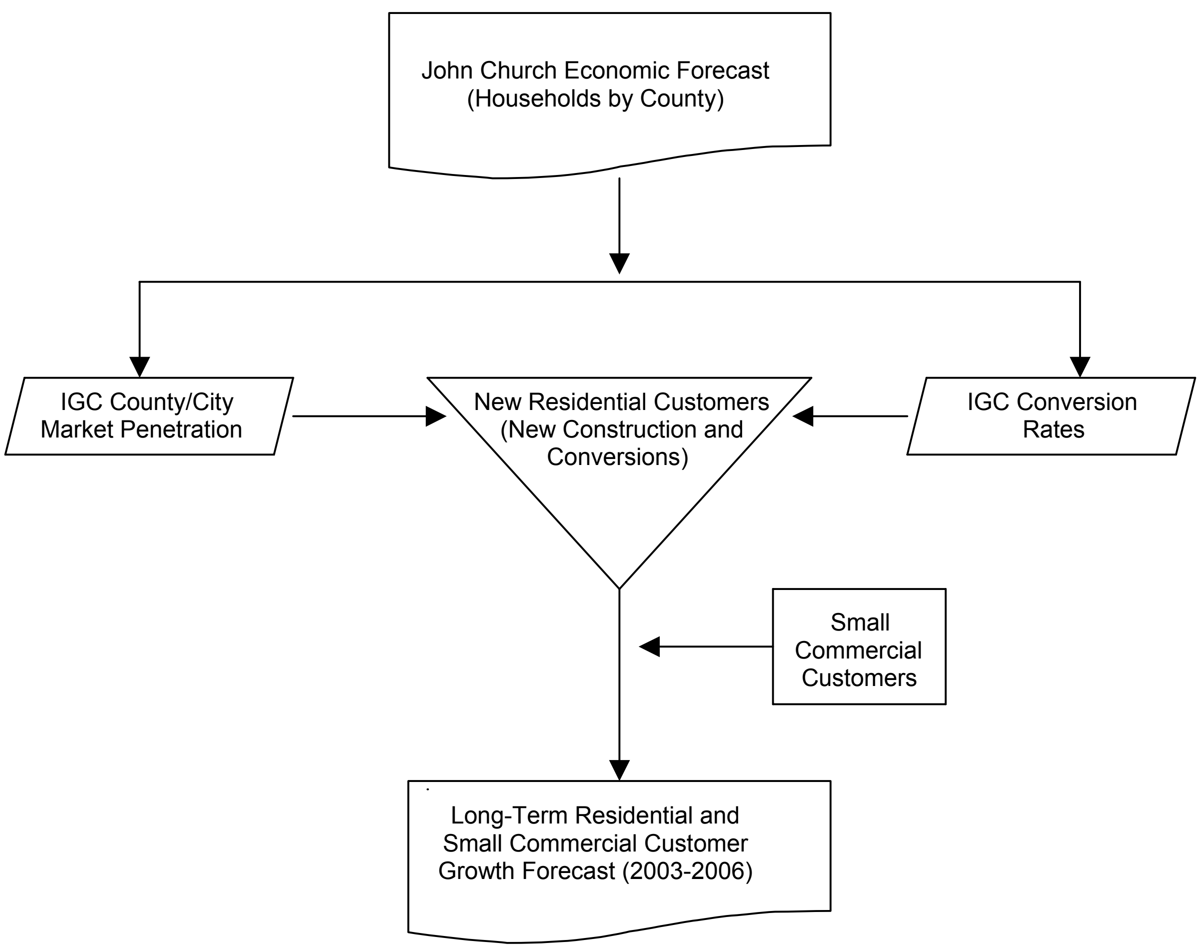
This section of the Intermountain Gas Company ("IGC") Integrated Resource Plan describes and summarizes IGC's residential and small commercial customer growth forecast for the years 2003 through 2007. This forecast provides a long-term look at IGC's residential and small commercial growth by county for IGC's current service territory. Customer growth is the primary driving factor of IGC's long-term demand forecast contained with IGC's IRP.

Summary

IGC's customer growth forecast includes three (3) key components:

- residential new construction customers
- residential customers who convert to natural gas from an alternative fuel
- small commercial customers

Subsequent sections of this report will explore each of these components in detail. The flowchart below illustrates the relationships between the data and shows the process necessary for the final long-term residential and small commercial customer growth forecast.



To calculate the number of customers added each year, the annual change in households for each county in the IGC Service Territory is first determined using the Idaho Economics 2002 Economic Forecast for the State of Idaho ("Economic Forecast") by John S. Church, dated October 2001. (See Exhibit No. 2, Appendix A)

The October 2001 Economic Forecast provides county by county projections of output, employment and wage data for twenty-one (21) industry categories for the State of Idaho, as well as a population and household forecast. This simultaneous equation model uses personal income and employment by industry as the main economic drivers of the forecast. This model uses forecasts of national inputs and demands for those sectors of the Idaho economy having a national or international exposure. Industries that do not have as large a national profile, and are thus serving local communities and demands are considered secondary industries. Local economic factors, rather than the national economy determine demand for these products.

The Economic Forecast uses two methods for population projections: (1) a cohort-component population model in which annual births and deaths are forecast, and then the net number is either added to or subtracted from the population, and (2) an econometric model which forecasts population as a function of economic activity. The two forecasts are then compared and reconciled for each quarter of the forecast. Migration into or out of the state is arrived at in this reconciliation.

CUSTOMER GROWTH SCENARIOS

The Economic Forecast provided three scenarios: (1) baseline, (2) high growth, and (3) low growth. The baseline scenario assumes a normal amount of economic fluctuation and a normal business cycle. This becomes the standard against which changes in customer growth, as affected by the low and high growth scenarios can be measured.

The High and Low Growth Scenarios of the 2002 Economic Forecast present alternative views of the economic future of Idaho and its forty-four counties. The High Growth Scenario of the Economic Forecast presents a long-term vision of rapidly growing economy in Idaho. For example, the High Growth Scenario produces a projected statewide population of nearly 2,330,000 in the year 2025 versus a Base Scenario Idaho population forecast of 1,870,000 in the same year. This scenario presents an absolute population gain of nearly 1,012,000 over Idaho’s estimated 2001 population of 1,316,700 and an annual average compound rate of population growth of 2.4% per year.

Alternatively, the Low Growth Scenario of the 2002 Economic Forecast does not present a rosy economic outlook for the state of Idaho. In the Low Growth Scenario, Idaho’s 2025 population is projected to reach the much lower level of 1,490,500. The Low Growth Scenario’s projected 2025 population is 173,800 above Idaho’s 2001 population – an annual average compound growth rate of 0.5 percent per year.

While the High and Low Growth Scenarios of the Economic Forecast represent two significantly different views of Idaho’s economic future, they are not unprecedented. An examination of historic employment, population, and household growth over the 1970 through 2000 period was performed. This examination, using either 5-year or 10-year moving averages of the growth of 1-digit SIC code employment concepts, population, and households (in order to dampen the effects of peak periods of economic growth) revealed that historic levels have exceeded the projected rates of growth in the High and Low Growth Scenarios of the 2002 Economic Forecast.

The High Growth Economic Forecast Scenario:

Underpinning the High Growth Scenario is a continuation of stellar growth of Idaho’s manufacturing industries. The pattern of these future manufacturing employment gains are expected to look similar to the manufacturing growth experienced in Idaho during the 1990s – largely concentrated in the “high-tech” manufacturing industries of Non-electrical Machinery, Electrical and Electronic Equipment, and

Instruments. Furthermore, these future manufacturing employment gains are likely to be, as they were in the 1990s, spatially concentrated in the state. Five Idaho counties, Ada, Canyon, Bannock, Bonneville, and Kootenai, accounted for nearly ninety percent of the state's overall manufacturing employment gains in the 1990s. With the exception of Kootenai County, all of the above counties are within the Intermountain Gas Company service area.

These projected manufacturing employment gains, in turn, spur employment growth in the secondary industries found in the affected and nearby communities. These secondary industries include employment in: Transportation, Communications, and Utilities; Construction; Wholesale and Retail Trade; Finance, Insurance and Real Estate; the Service industries; and local serving elements of Government.

In the High Growth Scenario other basic industry sectors of the Idaho economy would contribute to future employment gains. A renewed interest in nuclear power as a means of generating electricity would bring renewed vigor and increased levels of employment to the US Department of Energy's Idaho Nuclear and Environmental Laboratory (INEEL). In addition, nuclear waste clean-up activities at INEEL are programmed to accelerate in the next decade, causing a further upswing in INEEL employment levels. Indirectly, these would boost secondary industry employment growth in the Eastern Idaho counties of Bannock, Bingham, Bonneville, Jefferson, and Madison – all within the Intermountain Gas Company service area.

However, even in the High Growth Scenario not all of the state's existing manufacturing firms will grow in the future. Idaho's manufacturing industries of Lumber and Wood Products, Food and Kindred Products, and Chemicals and Allied Products industries are likely to face a long-term decline in activity and employment levels in almost any scenario. In addition, two other traditional mainstay Idaho industries, Mining and Agriculture, are likely to face a long-term future of no-growth or a slow level of decline in both levels of output and employment.

In the High Growth Scenario Idaho's natural rate of population growth (population, plus births, minus deaths) remains near current levels – about 1.1% per year. However, the economic outlook with a projected high rate of employment growth in Idaho subsequently produces a high level of population in-migration to the state.

In the High Growth Scenario Idaho population is projected to increase at an annual average compound rate of 2.4% per year over the 2001 to 2025 period. Statewide population in the High Growth Scenario is projected to increase by 1,012,100 from 1,294,000 in 2000 to nearly 2,329,000 in the year 2025. Furthermore, nearly 80% of that population growth is projected to occur in Southern Idaho.

In High Growth Scenario of the 2002 Economic Forecast, the number of households in Idaho is predicted to increase at an annual average rate of 2.5% per year, yielding an absolute increase of nearly 400,000 households in the 2001 to 2020 period. As with the High Growth Scenario population forecast nearly 80% of that population growth is projected to occur in Southern Idaho largely within the Intermountain Gas Company service area.

The Low Growth Economic Forecast Scenario:

In the Low Growth Scenario of the 2002 Economic Forecast Idaho's manufacturing industries do not provide the stimulus to growth as they have in the past. Today, many of Idaho's manufacturing firms are suffering under conditions caused by the current economic slowdown, as are many manufacturing industries nationally and internationally. However, the Low Growth Scenario of the 2002 Economic Forecast assumes that many of today's struggling manufacturing facilities will not survive the current recession.

The Low Growth Scenario's projected manufacturing employment losses and accelerated rates of declining employment, in turn, dampen employment growth in the secondary industries found in the affected and nearby communities. Again, these secondary industries include employment in: Transportation, Communications, and Utilities; Construction; Wholesale and Retail Trade; Finance, Insurance and Real Estate; the Service industries; and local serving elements of Government.

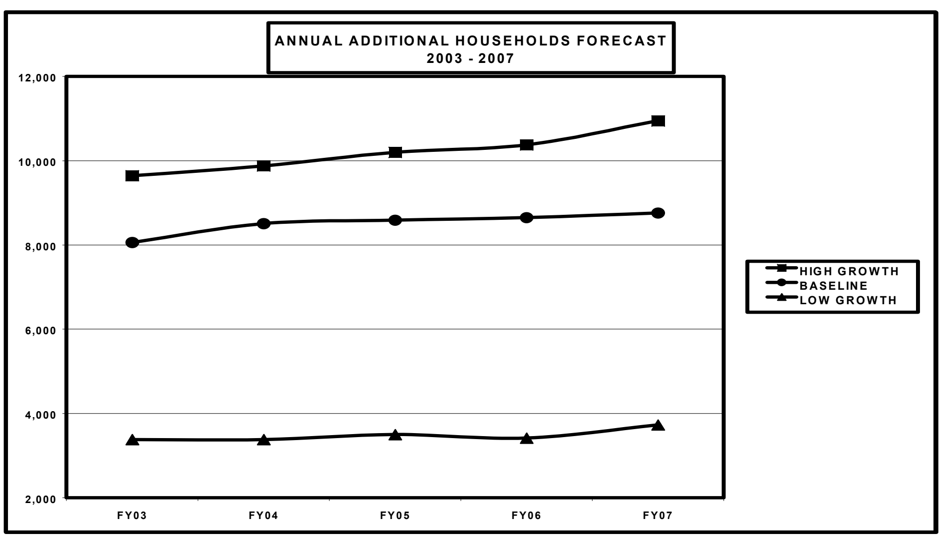
In the Low Growth Scenario other industry sectors economy do not provide significant contributions to future employment gains. Employment at the US Department of Energy's Idaho Nuclear and Environmental Laboratory (INEEL) are cut as federal funding is further curtailed.

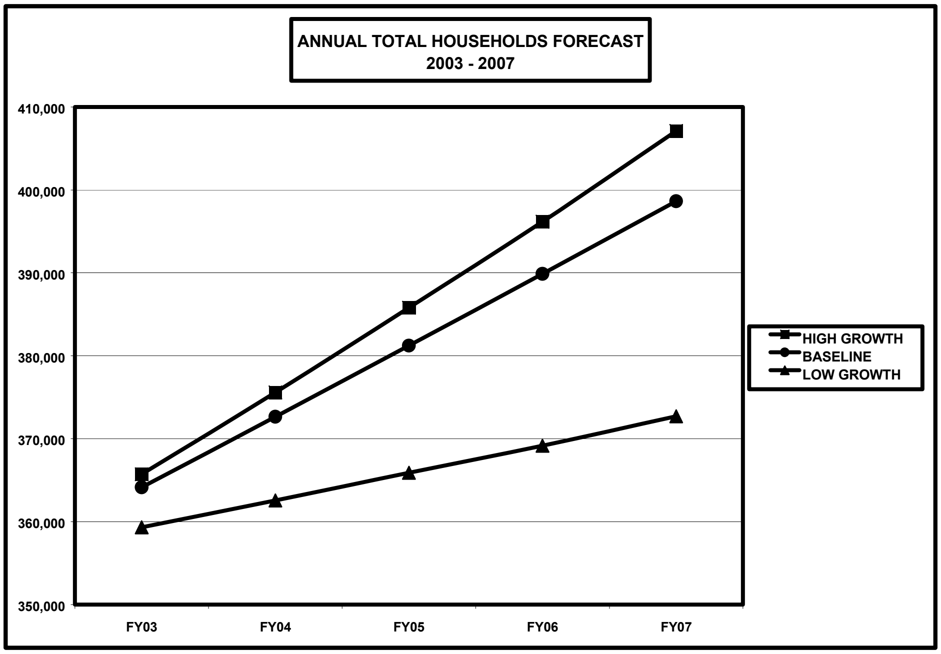
In the Low Growth Scenario Idaho's natural rate of population growth declines from its current level – near 1.1% per year – to a level that more closely matches the projected natural rate of US population growth – 0.7% per year. In addition, the Low Growth Scenario economic outlook with a projected low rate of employment growth in Idaho produces a modest level of population out-migration as Idaho fails to produce jobs at a rate high enough to satisfy the future job seekers.

In the Low Growth Scenario Idaho population is projected to increase at an annual average compound rate of 0.5% per year over the 2001 to 2025 period. Statewide population in the Low Growth Scenario is projected to increase by 173,800 from 1,294,000 in 2000 to nearly 1,490,500 in the year 2025. Nevertheless, the expectations are that nearly 80% of that projected population growth will occur in Southern Idaho.

In Low Growth Scenario, the number of households in Idaho is predicted to increase at an annual average compound rate of 0.8% per year, yielding a modest absolute increase of nearly 106,400 households during the 2001 to 2020 period. Nevertheless, expectations are that slightly over 80% of the Low Scenario's projected household gains will occur in Southern Idaho.

The following graphs illustrate the relationship between the three economic scenarios for the annual total households forecast and the annual additional households forecast for the IGC Service Territory counties.





The customer growth forecast is broken out by specific geographic regions within Intermountain Gas Company's service territory. The regions were chosen based upon the anticipated need for system upgrades within each region.

The Regions are as follows:

- The Canyon County Region, which consists of the Core Market Customers in Canyon County, along with the corresponding IGC distribution plant serving those customers

- The Sun Valley Lateral Region, consisting of the Core Market Customers in Blaine and Lincoln Counties, along with the corresponding IGC distribution plant serving those customers

- The Idaho Falls Lateral Region, consisting of the Core Market Customers in Bingham, Bonneville, Fremont, Jefferson, and Madison Counties, along with approximately 3% of the Core Market Customers in Pocatello, Bannock County, along with the corresponding IGC distribution plant serving those customers

- The All Other Customers Region, consisting of the Core Market Customers in Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington Counties, along with the corresponding IGC distribution plant serving those customers. Additionally, 97% of the Core Market Customers in Pocatello, Bannock County, as well as the rest of Bannock County, and their corresponding distribution plant are included in this node.

IGC's customer growth forecast includes three (3) key components:

- Residential New Construction Customers
- Residential Customers who convert to natural gas from an alternative fuel
- Small Commercial Customers

INTERMOUNTAIN GAS COMPANY "MARKET SHARE"

IGC utilizes market penetration rates that vary across the service territory. These regional penetration rates are applied to the IGC service-territory counties, within the three specific regions; west, central, and east. These penetration rates are the ratio of IGC's additional residential new construction customers to the total building permits in those regions. Forecast additional households multiplied by the regional market penetration rate equals the anticipated residential new construction customers.

IGC derives the regional market penetration rates by dividing the fiscal year regional residential new construction sales total by the number of regional residential building permits compiled by the Wells Fargo Bank Construction Report ("Wells Report"). The Wells Report arranges the data by city, as well as unincorporated portions of the more populous counties in Idaho. These city/county tallies are reconciled to IGC's residential sales by IGC's company town codes for valid comparison, and are then collapsed to the county level.

IGC also develops another market penetration rate by way of the county construction reports which IGC marketing and construction personnel use in prospecting for new construction customers. Again, as above, the residential new construction sales in the specific areas covered by these reports are divided by the total dwellings listed in these reports, to derive the market penetration rate. The areas covered here are the major population centers in the IGC Service Territory: Ada/Canyon County, Twin Falls/Wood River Valley, Pocatello/Soda Springs, and Idaho Falls/Rexburg. These market penetration rates are derived month by month, and are compared and reconciled to the market penetration rates derived using the Wells Report.

The market penetration rates used in the customer forecasting varied somewhat when going into the future out of anticipated market share gains in the Central and Eastern regions. Those for the West remained relatively static through the forecast period, since they are already near 100%. The same set of market penetration rates was used in the baseline, high growth, and low growth scenarios. (See Exhibit No. 2, Appendix B)

MARKET PENETRATION RATES

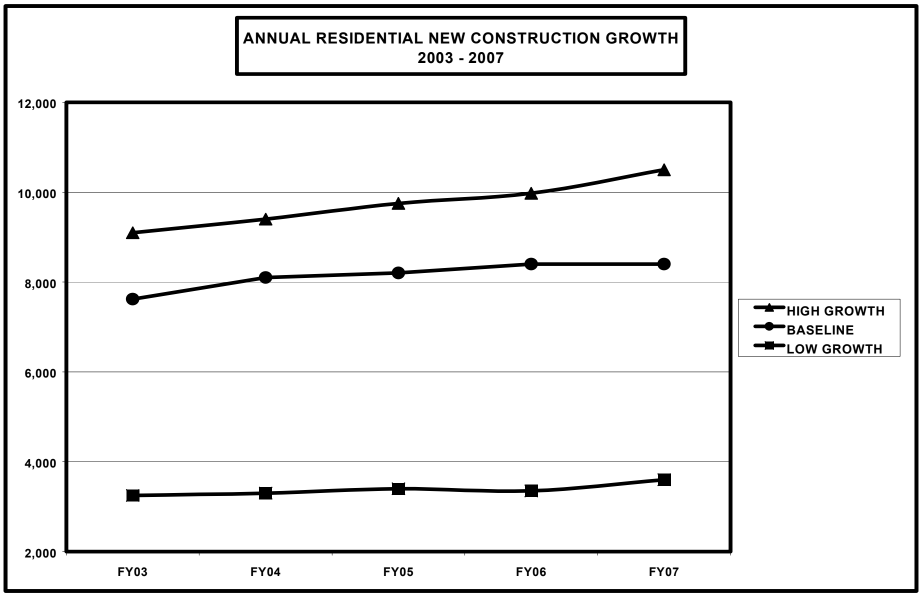
	FY03	FY04	FY05	FY06	FY07
Western Region	98%	98%	98%	98%	98%
Central Region	85%	87%	87%	87%	87%
Eastern Division	88%	90%	92%	94%	94%

The annual change in households by county, per the Economic Forecast, is multiplied by IGC's market penetration rate in that region to determine the additional residential new construction customers. Next, that number is multiplied by the IGC conversion rate, which is the anticipated percentage of conversion customers relative to new construction customers in those locales. This results in the number of expected residential conversion customers, and when added to the residential new construction numbers, the total expected additional residential customers across the periods is derived, by county.

The residential new construction numbers by county are also multiplied by the IGC commercial rate, which is the anticipated percentage of commercial customers relative to residential new construction customers in those locales, to arrive at the number of expected additional small commercial customers.

The residential numbers must be split across our two residential rate classes, RS-1 and RS-2, since these classes have different load patterns. RS-1 is a customer who does not have both a gas furnace and a gas water heater, regardless of other appliances. RS-2 customers have at least a gas furnace and a gas water heater. Virtually 100% of IGC's residential new construction customers go RS-2, while only regionally varying percentages of IGC's residential conversion customers go RS-2. So, the additional residential conversion customers are split, depending on the region.

The following graph illustrates the relationship between the three economic scenarios for the annual residential new construction growth forecast for 2003 – 2007:



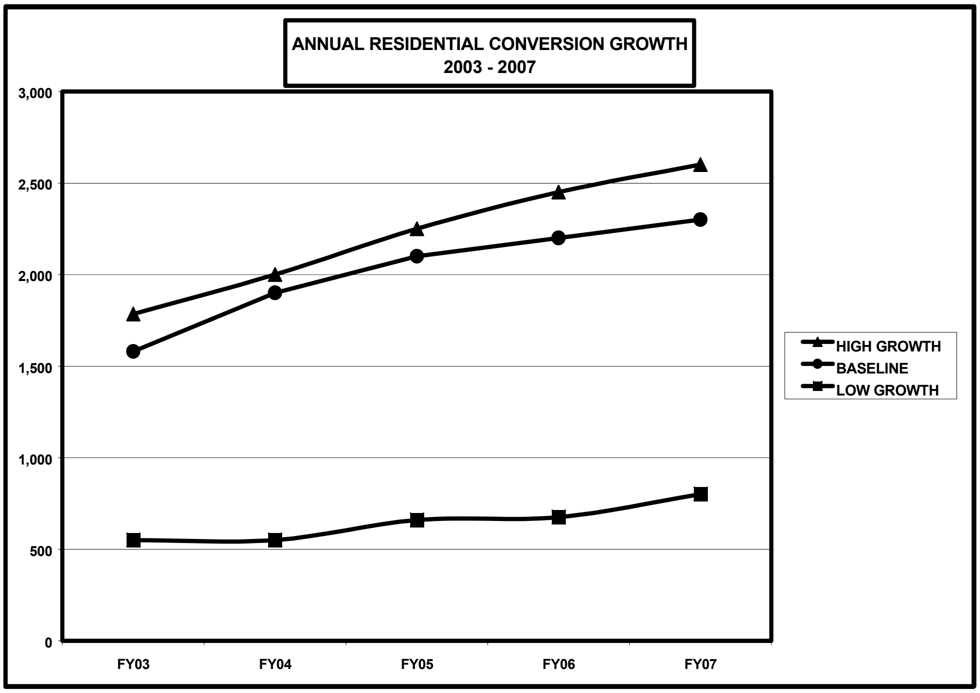
Conversions

The conversion market represents another source of customer growth. IGC acquires these customers when the homeowner replaces an electric, oil, coal, wood, or other alternate fuel source furnace/water heater with a natural gas unit. IGC forecasts these customer additions by applying regional conversion rates based on historical data and future expectations (See Exhibit No. 2, Appendix C). During a high and low growth scenarios, the rates are adjusted to maintain reasonable expectations within the context of those alternative economic climates. The following table shows, by region the assumed conversion rates over the five-year period.

REGIONAL CONVERSION RATES

	FY03	FY04	FY05	FY06	FY07
Western Region					
Baseline	17%	19%	21%	23%	23%
High Growth	14%	16%	17%	19%	19%
Low Growth	32%	32%	31%	31%	30%
Central Region					
Baseline	30%	32%	34%	36%	36%
High Growth	35%	35%	37%	37%	38%
Low Growth	125%	105%	130%	130%	140%
Eastern Division					
Baseline	30%	35%	40%	45%	45%
High Growth	31%	32%	36%	39%	38%
Low Growth	120%	130%	140%	135%	95%

The following graph illustrates the relationship between the three economic scenarios for the annual residential conversion growth forecast for 2003 – 2007:



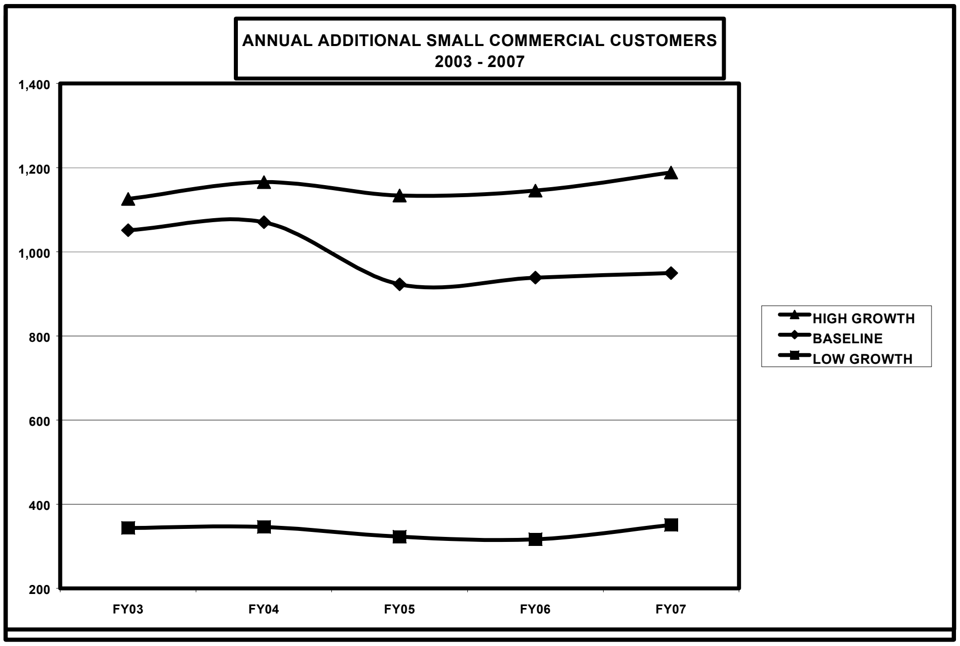
Small Commercial Customers

Small commercial customer growth is forecast as a certain proportion of new construction customer additions. The logic being that as household growth drives the major proportion of IGC's residential customer growth, household growth therefore drives small commercial customer growth. New households require additional new businesses to serve them. Based on recent IGC sales data, this ratio of small commercial customer growth to new construction residential varies across the IGC system, and thus different regional rates for small commercial customer growth are used, and are as follows:

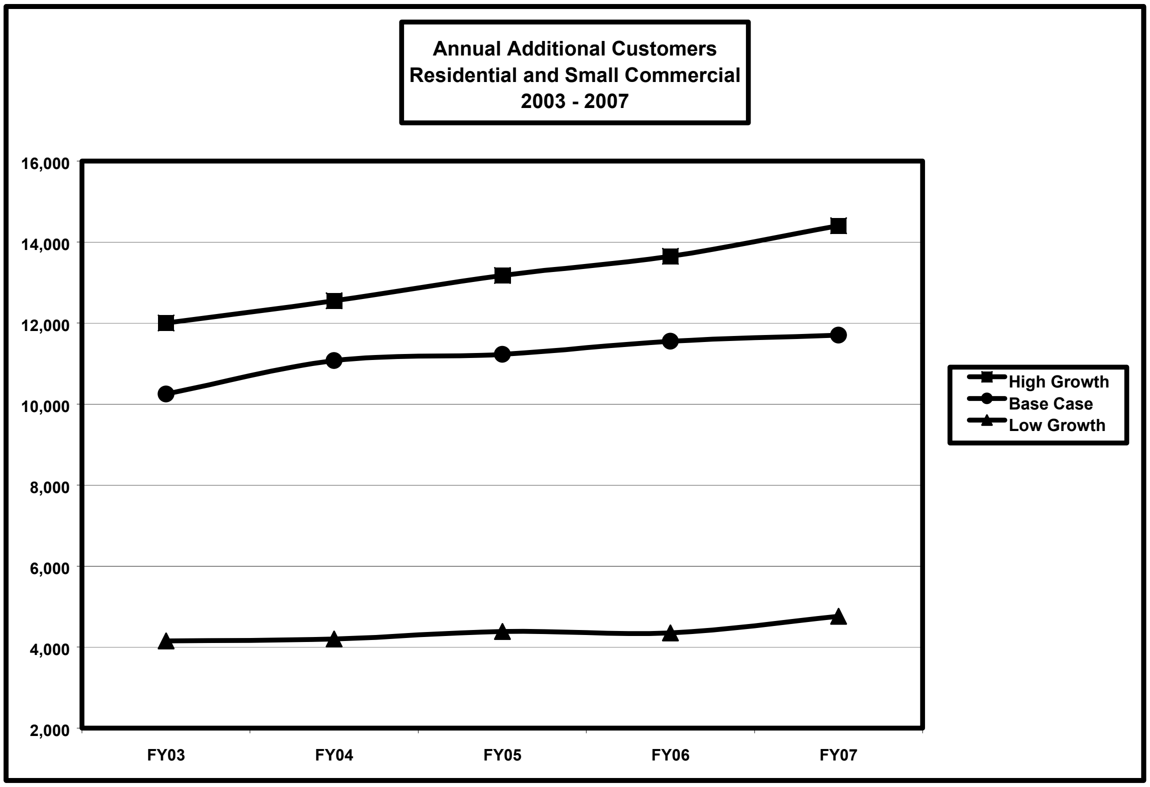
REGIONAL SMALL COMMERCIAL CUSTOMER TO RESIDENTIAL NEW CONSTRUCTION CUSTOMER GROWTH RATIOS

	FY03	FY04	FY05	FY06	FY07
Western Region					
Baseline	9%	9%	8%	8%	8%
High Growth	9%	9%	8%	8%	8%
Low Growth	9%	9%	8%	8%	8%
Central Region					
Baseline	27%	20%	20%	20%	20%
High Growth	20%	20%	20%	20%	20%
Low Growth	20%	20%	20%	20%	20%
Eastern Division					
Baseline	25%	25%	19%	19%	19%
High Growth	20%	20%	20%	19%	18%
Low Growth	20%	20%	20%	19%	18%

The following graphs show the annual total, as well as the annual additional small commercial customers for the period 2003 – 2007:



The following graph shows the annual additional customers for each of the three economic scenarios.



The following table shows the results from the 5-year customer growth model for each scenario for the total customers at each year-end, and the annual additional, or incremental, customers:

	Range as a % Of Base Case	Average as a % of Base Case	Range as a % Of Base Case	Average as a % of Base Case
Low Growth	88% - 97%	93%	38% - 41%	39%
Baseline	100% - 100%	100%	100% - 100%	100%
High Growth	101% - 104%	102%	113% - 123%	118%
	Range (2003 – 2007)	Average	Range (2003 – 2007)	Average
Low Growth	237,587 – 255,282	246,270	4,150 – 4,760	4,369
Baseline	243,687 – 289,232	266,238	10,250 – 11,700	11,159
High Growth	245,612 – 299,387	271,897	12,000 – 14,400	13,155

INDUSTRIAL FORECAST

Introduction

A survey to determine the projected natural gas usage of each industrial customer served by Intermountain Gas Company was completed in the Spring of 2001 (See Page 25). The survey included a cover letter explaining the intent of the requested information with the assurance that all responses would remain confidential (See Page 24). The survey form was sent to the management of each of Intermountain's 118 large volume contract customers and identified their historical usage on an annual, peak month and peak day basis for the past two years ending 2000. This information helped provide a basis for each customer to determine their future natural gas requirements. Additional information was requested as to each customer's alternative fuel capabilities and if there was a desire for additional service options from Intermountain.

The results of the survey was used to forecast three distinct and separate large volume customer forecasts for a six year period, commencing in 2002. The projections incorporate information from the customer's management, engineers and marketing personnel regarding plant expansion or modification, equipment replacement and anticipated product demand. Other forecast data was then utilized to adjust the survey data base for two of the three forecasts (see below). The 118 customers were further refined into six separate sub-groupings comprising of :

- Seventeen potato processors
- Forty-two other food processors which including sugar, milk, beef and seed companies
- Five chemical and fertilizer companies
- Twenty light manufacturing companies which includes electronics, paper and asphalt companies
- Twenty-four schools and hospitals, and
- Ten other miscellaneous companies

High Demand Forecast

The High Demand, or most optimistic, forecast figures are used directly from the customer survey, as it was completed in early summer of 2001. The table below summarizes the high demand forecast:

	FY 03	FY 04	FY 05	FY 06	FY 07	Compound Rate of Growth
Potato Processors	112,457,616	113,174,065	114,676,189	114,897,111	114,927,111	0.5%
Other Food Processors	54,483,058	56,864,561	57,891,727	58,608,769	58,728,976	1.9%
Chemical Fertilizers	68,760,349	68,560,349	68,848,349	68,848,349	68,848,369	-
Manufacturers	19,177,514	19,192,924	19,286,041	19,286,041	19,291,041	0.1%
Institutions	12,086,497	12,497,938	12,698,561	13,538,169	13,900,394	3.6%
Other & Special	16,367,749	18,459,669	19,001,969	19,768,694	20,270,994	5.5%
Total High Forecast Therm Sales	**283,332,783**	**288,749,506**	**292,402,836**	**294,947,133**	**295,966,885**	1.1%

The primary changes by each segment are due to:

I. The Potato Processors growth incorporates the following assumptions:
   a. drought conditions continuing into 2002 and then a return to more normal weather in 2003

b. the return of lower natural gas prices versus oil and
c. the expansion of plants for several of the larger facilities

This results in an increase of 2.5 million therms, or a compound growth rate of 0.5%.

II. Other food processors were projected to increase 4.2 million therms, or a compound growth rate of 1.9%. The primary reason for the increase is due to an increase by several of the large milk and beef processors.

III. Chemical Fertilizers are anticipated to remain essentially flat over the forecast period. The forecast incorporates the closure of the FMC facility.

IV. The group of twenty manufacturing customers, consisting of five electronics facilities, seven asphalt companies and other light manufacturing is anticipated to increase by 88,000 therms, or 0.1%.

V. Institutions are anticipated to increase 3.6% over the six-year period, or 1.8 million therms, with the primary increase in usage due to new buildings being constructed at existing universities and hospitals.

VI. Other: This group is anticipated to increase 5.5% or 3.9 million therms. This segment generally reflects a mature group of hotels, resorts, and other companies not expecting large increases in growth. However, two new plants are forecasted to be built in 2004, with continued expansion through 2007.

Baseline (Median) Demand Forecast

The Baseline (Median) Demand Forecast was based upon the customer survey, but incorporates a lower projected base usage for a total increase of 0.8%, or 9.4 million therms as follows:

	FY 03	FY 04	FY 05	FY 06	FY 07	Compound Rate of Growth
Potato Processors	111,941,829	112,938,184	114,318,184	114,568,184	114,568,184	0.6%
Other Food Processors	53,830,911	56,251,878	57,276,878	57,916,878	57,916,878	1.8%
Chemical Fertilizers	68,348,349	68,348,349	68,458,349	68,848,349	68,848,349	0.2%
Manufacturers	18,469,046	18,507,413	18,957,413	19,029,413	19,029,413	0.8%
Institutions	11,985,517	12,072,420	12,725,963	12,787,963	12,787,963	1.6%
Other & Special	15,741,469	16,266,469	16,291,469	16,566,469	16,566,469	1.3%
Total Median Forecast Therm Sales	**280,317,121**	**284,384,413**	**288,118,256**	**289,717,256**	**289,717,256**	**0.8%**

I. Potato Processors are anticipated to increase 0.6% or 2.7 million therms over the period. This group of 17 customers is projecting an increase in the first two years and then a flat rate of growth in the last 3 years of the five-year period.

II. Other Food Processors: This group of customers is forecasted to increase 1.8%, or 4.1 million therms. The change is primarily due to an increase in milk production and a return to a higher demand for agriculture products.

III. Chemical Fertilizers are projected to remain essentially flat over the forecast period. The forecast includes the closure of FMC and a lower production rate in the first two years of the projected usage by the five facilities in this group.

IV. The Manufacturing group is projected to increase 0.8%, or 500,000 therms. The growth rate is primarily due to expanded manufacturing by the four electronic facilities.

V. Institutions: This group is projected to increase 802,000 therms, or 1.6% over the forecasted period. The increase is due to added buildings at the universities and hospitals throughout the service area.

VI. Other: this group is projected to increase 0.1%, or 75,000 therms, over the five-year period. The increase is primarily due to the assumption of a new customer added in 2004 and expanding to 750,000 therms in the fifth year.

Low Demand Forecast

The Low Demand Forecast is identical to the Baseline (Median) Forecast with the exception of oil usage by the Potato Processors and no new customers added throughout the forecast period. The assumption was made that if natural gas prices were higher than oil, those customers who have the capability to switch would do so throughout the five-year period. Six potato processors were identified who have oil standby and would likely switch to oil during the winter months. This results in a total incremental increase in this group of 2.0 million therms, or 0.5% over the five-year period.

The total change for the Low Forecast is a total increase of 8.0 million therms or 0.7%, as shown below.

	FY 03	FY 04	FY 05	FY 06	FY 07	**Growth Rate**
Potato Processors	100,489,115	100,839,115	102,219,115	102469115	102,469,115	0.5%
Other Food Processors	53,830,911	56,251,878	57,276,878	57,916,878	57,916,878	1.8%
Chemical Fertilizers	68,348,349	68,348,349	68,548,349	68,848,349	68,848,349	-
Manufacturers	18,469,046	18,507,413	18,957,413	19,029,413	19,029,413	0.8%
Institutions	11,985,517	12,072,120	12,725,963	12,787,963	12,787,963	1.6%
Other & Special	15,741,469	15,766,469	15,791,469	15,816,469	15,816,469	0.1%
Total Low Forecast Therm Sales	**268,864,407**	**271,785,344**	**275,519,187**	**276,868,187**	**276,868,187**	**0.7%**

Service Options

Intermountain provides several differing types of sales and transport service to its large-volume industrial customers as described below.

Intermountain's full requirements LV-1 sales service tariff, was the original type of service offered to the industrials. Under this tariff, Intermountain provides to the customer a fully bundled service including the daily natural gas supply, firm interstate transportation, and firm distribution capacity. With the introduction of NWP's transportation tariffs, new and advantageous alternatives became available to the larger industrials.

At the request of the industrial customers, Intermountain expanded its industrial service by offering the T-1 Transportation Tariff. This service allows customers the opportunity to purchase their own gas supplies from marketers or producers while continuing to utilize Intermountain's firm interstate capacity. The customer is fully responsible to deliver the required gas supply to applicable receipt points on NWP's mainline. Intermountain continues to provide both firm interstate transportation and distribution delivery in order to move the customer's gas supply through NWP and Intermountain's distribution system to the customers' facilities.

Through the active management of the Company's firm interstate mainline capacity, significant capacity-related issues became apparent to Intermountain. Even after adding over 733,000 therms of new interstate capacity early in the 1990's, the Company recognized that the rate the system loads were growing would necessitate the need to contract for further interstate capacity before the end of the decade. Intermountain recognized the opportunity to forestall the need to secure new interstate mainline capacity by providing the industrial customers the economic opportunity to secure their own interstate pipeline through NWP's capacity release mechanism thereby freeing up interstate capacity for core market growth. Consequently, the Company implemented additional transport services, each designed for the dual purpose of meeting specific needs of the industrial market and to preserve interstate mainline capacity for the core market.

The T-2 tariff is similar to T-1 except that the customer is required to elect a daily Contract Demand ("CD") based on historical peak day usage. This allowed Intermountain to reserve a quantity of firm interstate and distribution capacity to serve that customer's load. Once set however, no further growth in the CD was allowed. Daily usage over the daily CD, or overrun, is billed either at a higher overrun rate, an interruptible rate, or at T-4 rates (see below). Due to lack of further interest in this service, this tariff is no longer available except to existing "grandfathered" customers.

The Company recognized that a large segment of the industrial market could benefit economically by securing their own interstate capacity. It also recognized that certain of those customers had non-critical processes and could afford the risk of interruption (i.e. non-firm distribution capacity) if compensated for that risk. Consequently, Intermountain introduced the T-3 tariff. Differing from both T-1 and T-2 service, the T-3 customer must arrange with pipelines and/or marketers to obtain both gas supply and interstate transport capacity. The Company receives the customer's gas supply from NWP and redelivers it to the industrial's facility on an interruptible basis – meaning such a customer may be bumped off the system during periods of peak constraint. Of course, the industrial is only authorized to use the amount of supply that it delivers to Intermountain.

Other industrial customers wanted the option to purchase supply and interstate capacity but also needed the security of firm distribution capacity so Intermountain designed the T-4 tariff. Like the T-3 tariff, the T-4 customer is fully responsible to deliver the required gas supply to Intermountain's citygates. The difference is that once the supply is delivered to IGC, the gas is redelivered to the industrial on a firm basis through the distribution system.

Firm Contract Demand:

The survey requested information as to each customer's future peak requirements along with their forecasted annual usage. Many of the largest customers indicated their peak day would not increase, but their off peak-day requirements would, due to less week-end downtime, etc. The individual customer's peak-day requirements are used to analyze the potential need for future upgrades to existing laterals serving each community. The Maximum Daily Firm Quantity (MDFQ) for existing and any new customer's in the (LV-1), (T-1), (T-2) classes was not increased over the forecast period. This is due to Intermountain's plan to minimize any future purchases of additional firm interstate transportation for the large volume customers. The current firm daily interstate capacity, per Intermountain's contract with the LV-1, T-1 and T-2 customers, is 408,675 therms. The total firm T-4 firm distribution transportation service, which is site specific on Intermountain's distribution system, is 491,822 therms per day.

The firm peak day therm requirements, or demand, by type of service are shown on the following page:

TOTAL FIRM DAILY INTERSTATE AND DISTRIBUTION DEMAND REQUIREMENTS

Tariff	
Large Volume Firm Sales Services (LV-1)	29,675
Firm Transportation Services (T-1)	320,930
Firm Transportation Service with Maximum Daily Demand (T-2)	58,070
Total	408,685

SAMPLE OF SURVEY COVER LETTER

April 27, 2001

customer name
address
city, state, zip

Re: customer name

Dear __________

In order to meet your future natural gas needs, we will need a projection of your future incremental requirements on an annual, monthly, and peak day basis. To assist in your projection, we have included historical usage information for the prior two years (beginning in January 1999) on the enclosed survey form.

The increasing natural gas usage that has taken place over the past five years as a result of the grown in the residential and commercial sector, and the expanding industrial requirements in southern Idaho, has demanded additional emphasis on forecasting our customer's future needs. An Order from the Idaho Public Utilities Commission also requires Intermountain Gas Company to document its supply and demand forecasting efforts as an added assurance that we are meeting our customer's needs at the lowest system cost consistent with supply reliability.

We want to re-emphasize our commitment to continue reliable firm large volume sales and firm transportation services to you as a valued customer of Intermountain Gas Company.

We appreciate your busy schedule and the effort required to complete this survey. However, only with your assistance will we be able to accurately plan for the future to continue to provide you with the highest quality service. Please return your completed survey, including any comments you have by May 18th, 2001. After evaluating the responses, I will contact you concerning our plans for the future.

Should you have any questions, or if I can be of assistance to you, please call me at (208) 377-6053.

Very truly yours,

Daniel A. McAlister
Industrial Services Manager

DAM/slk

Enclosure

SAMPLE OF SURVEY FORM

Account Name: Account Number:
Existing Tariff: Daily Contract:

Historical Information

Most Recent 24 Months	Annual Usage	Peak Monthly Usage	Date of Peak Month	Peak Day Usage	Date of Peak Day
12 months ended December 31, 2000					
12 months ended December 31, 1999					

Requested Information – Projected Usage

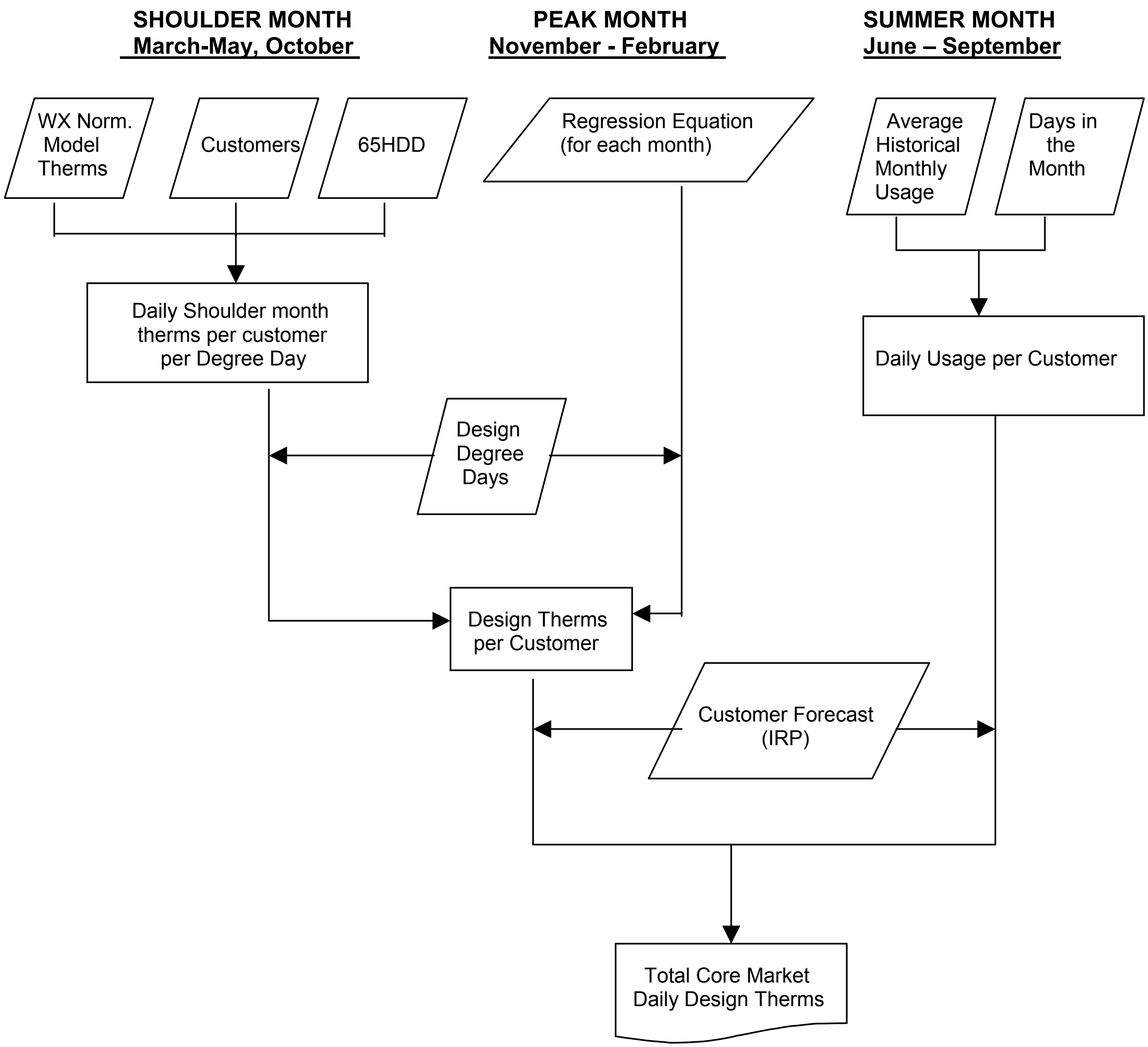
Description [Usage Figures in Therms]	Calendar 2000	Calendar 2001	Calendar 2002	Calendar 2003	Calendar 2004	Calendar 2005	Calendar 2006	Calendar 2007	Calendar 2010
Annual Usage									
Peak Monthly Usage									
Peak Day Usage									
Month of Peak Day									

1. What is the prime reason for the projected change in usage?
2. What is your existing alternative source of energy? None ☐ Coal ☐ Oil ☐ Other ☐
3. What percent of your current peak day energy needs, served by natural gas, can be served by existing alternative fuel? _____%
4. If you do not currently have an alternative energy source, what would be your preference? None ☐ Coal ☐ Oil ☐ Other ☐
5. What additional options would you consider or suggest to enhance your service?______________________________

THE INFORMATION PROVIDED ON THIS FORM WILL REMAIN CONFIDENTIAL WITH INTERMOUNTAIN GAS COMPANY

USAGE PER CUSTOMER UNDER DESIGN DEGREE DAYS

This section of the Intermountain Gas Company (IGC) Integrated Resource Plan (IRP) describes and summarizes the usage per customer under design weather conditions. These results, combined with the customer forecast results, develop the load duration curve for the IRP. The following flowchart illustrates the development of daily residential and small commercial market therms utilizing design degree-days.



The following sections more fully explore the derivation of the usage per customer assumptions during peak months, as well as non-peak months. Each section includes information regarding equation development, variables, methodology, results, and customer assumptions.

CUSTOMER USAGE DURING PEAK MONTHS

Variables

Usage per customer per degree-day under design weather is based upon a multiple regression equation for each month during the peak heating season (i.e. November through February).

The dependent variable, peak usage per customer, is calculated by dividing the total residential and small commercial market sendout for each day during each of the peak months by total residential and small commercial customers for each day during each of the peak months. Daily customers are developed by evenly spreading the difference between the customers at the beginning of the month and the customers at the end of the month to the days of the month.

An eleven-year historical database, using data from 1989 through 1998, was used to develop the dependent variable (See Exhibit 3, Appendix A). A starting point of 1989 was selected for the database, because of a structural shift that has occurred in the data. During the late 1980's and early 1990's, the effects of tighter Federal and State equipment efficiency standards and new building codes, which incorporate higher efficiency standards, have led to a decrease in usage per customer per degree day (See "The Efficient Use of Natural Gas"). In addition, the rapid customer growth of the 1990's means that an increasing percentage of the customer base is using this more efficient equipment. As a result of this change in usage per customer, models using the 1989 through 1998 data provided a much better statistical fit than models that included the older data.

Models using data through 2000 were also tested, but the warmer than normal winters of the past few years appear to have created some anomalies in the data. The weather included in the 1989 through 1998 data more accurately represents customer usage in normal or colder than normal years.

The independent variables consist of the actual sixty-five heating degree-days (65HDD) for each day during the peak months and a weekend binary variable. The weekend binary variable, a one (1) if Saturday or Sunday, and a zero (0) if Monday through Friday, helps establish whether or not a relationship exists between usage and the weekend.

Methodology and Results

A regression equation was developed for each of the peak months. The independent variables, daily 65HDD and weekend binary, were regressed against the dependent variable, daily usage per customer, to detect any relationship between the dependent and the independent variables (See Exhibit 3, Appendix B).

In order to evaluate this relationship, two statistical measurements were employed: the adjusted R2 and the F-statistic. The adjusted R^2 determines what percent of the variability in usage is explained by the independent variables. The F-statistic determines whether or not the regression equation as a whole is significant. A table of the adjusted R^2 and the F-statistic follow:

PEAK-DAY USAGE REGRESSION EQUATION RESULTS		
MONTH	ADJUSTED R^2	F-STATISTIC
NOVEMBER	84.8%	749.12
DECEMBER	90.3%	1294.07
JANUARY	88.6%	1207.54
FEBRUARY	77.7%	487.94

After the regression equations were developed, design degree-days were used in the models in place of 65HDD to calculate the daily usage per customer during the peak months. (See Exhibit 3, Appendix C-E).

CUSTOMER USAGE DURING SHOULDER MONTHS

Customer usage during the shoulder heating months (i.e. March through May and October) is based upon an average usage calculation from Intermountain's weather normalization model. Monthly therm usage from the weather normalization model is divided by customers and 65hdd to develop a daily usage per customer per degree-day. The following table shows the approximate therms per customer per degree-day for each of the shoulder heating months.

USAGE PER CUSTOMER DURING SHOULDER MONTHS		
MONTH	***THERMS/CUSTOMER/65 HDD***	***DESIGN 65HDD***
MARCH	0.182	963
APRIL	0.168	585
MAY	0.163	296
OCTOBER	0.186	524

This daily usage per customer per degree day figure was then multiplied by the design degree days to show the usage per customer, under design weather conditions, for each of the shoulder heating months.

CUSTOMER USAGE DURING SUMMER MONTHS

Customer usage during the summer months (i.e. June through September) is based upon an average historical monthly usage. The average monthly usage is divided by the days in the month to generate average daily usage. Since heating degree-days have no influence in increasing usage during the summer months, only customer growth causes the summer load to increase. Daily average usage divided by number of customers equals therms per customer. The following table shows the daily therms per customer for each of the summer months.

USAGE PER CUSTOMER DURING SUMMER MONTHS	
MONTH	***THERMS/CUSTOMER/65HDD***
JUNE	0.11
JULY	0.08
AUGUST	0.07
SEPTEMBER	0.09

The usage per customer for all three periods was then multiplied by the total residential and small commercial customers for that day (See Customer Forecast). This calculation results in total usage for each day.

Total daily usage for each peak month varied depending upon the customer growth assumption that was used (i.e. low growth, baseline, and high growth) (See Exhibit 3, Appendix C-E).

DESIGN HEATING DEGREE DAYS[1]

Intermountain Gas Company uses the demand forecast to determine and plan for future annual and peak day firm capacity requirement. The design degree-days provide a means to distribute the heat sensitive (core)[2] load portion of the forecast on a daily basis. See Design Degree-Days by Month in the table on the following page.

Design Development

A review of the last thirty years' of heating degree data from NOAA[3] (See Pages 32 - 33 for Degree-Day Data) was made to determine the limits of a design year. Due to their geographic locations, data from the Boise and Pocatello weather stations was used to represent the total distribution system's design degree-days. The review revealed Intermountain's coldest twelve consecutive months to be the fiscal year 1985 (October 1994 through September 1995). This period, with certain modifications, represents the basis for the design.

Design Month Modification

The coldest month for the last thirty years was December 1985 (1638 degree-day). For design purposes, December 1985 was substituted for January as the peak month.

The degree days for the remaining peak months were increased by one percent to assume the potential for even colder weather.

The summer months (May through September) were normalized.

The total design was made to assume a bell-shaped curve with peak at mid-January (See Page 34). This ensures a core peak to coincide with the peak industrial load that historically occurs in mid-January.

Design Peak Day Modification

The coldest day on record occurred on December 22, 1990 and was an 82 degree day average for Boise and Pocatello (i.e. Boise 82 degree day and Pocatello 81 degree day). For design purpose, an 84-degree day was used to reflect colder temperatures that have occurred in eastern Idaho. The average of the two reporting stations is representative of the temperature extremes that may be expected in each location throughout Intermountain Gas Company's service area. Additionally, although the peak day occurred in December, for planning purposes, it was assumed the peak day would occur in January.

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[1] The methodology was reviewed and approved by Idaho Climatologist Myron Molnow, Mowcow, Idaho
[2] The core market (heat sensitive) usage per customer as determined by the regression correlation analysis is multiplied by the design degree days to determine daily usage.
[3] NOAA - National Oceanic and Atmospheric Administration

TABLE #1

NORMAL AND ACTUAL HEATING DEGREE DAYS - FY 85/DESIGN

Month	Weighted Normal (30 yrs)	Actual Fiscal 1985	Design - Bell Shaped Curve
October	456	605	524
November	821	834	907
December	1145	1350	1332[1]
January	1159	1512	1638[1]
February	878	1196	1210[1]
March	724	1026	963
April	486	435	585
May	250	236	296
June	39	69	99
July	0	0	7
August	1	35	25
September	113	288	176
Total Year	6072	7586	7762[2]

[1] Design is 3.0% colder than the 1984-85 three month period December through February (critical planning months due to pipeline capacity restraint and rationing of storage gas)
[2] Design is 27.8% colder than normal year; 2.3% colder than FY 1984-85

Table #2

#2

HEATING DEGREE DAYS Base 65 deg. F BOISE, IDAHO

SEASON	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1965-66	7	30	234	265	613	1035	1004	881	650	407	192	57	5517
1966-67	7	18	68	496	654	1039	883	742	707	627	379	79	5581
1967-68	0	0	49	434	723	1146	1092	655	586	553	235	50	5566
1968-69	0	39	119	382	684	918	945	797	639	432	147	75	5547
1969-70	3	13	91	555	751	905	886	659	724	631	249	79	5603
1970-71	0	0	240	537	650	969	958	765	763	465	176	78	5601
1971-72	10	6	210	492	753	1069	1047	818	598	543	194	45	5785
1972-73	11	0	222	406	727	1270	1056	708	673	470	182	91	5816
1973-74	4	13	103	342	692	817	1099	728	687	452	304	42	5323
1974-75	10	11	55	301	689	983	1132	732	721	607	275	76	5790
1975-76	6	21	74	399	759	1055	1013	836	658	324	180	132	5896
1976-77	3	35	76	434	720	1097	1418	868	772	342	153	7	6151
1977-78	5	32	145	362	756	853	859	744	500	438	329	76	5152
1978-79	5	38	179	370	841	1171	1503	855	655	431	241	72	6415
1979-80	5	2	76	326	801	899	1070	725	736	367	257	133	5449
1980-81	0	41	104	409	790	983	957	763	651	432	315	97	5502
1981-82	15	5	137	497	624	915	1240	974	729	586	312	85	6120
1982-83	27	2	152	432	863	1030	897	653	622	530	309	81	5638
1983-84	38	0	145	353	682	1350	1353	1004	710	565	328	162	6616
1984-85	0	6	204	557	776	1399	1412	1094	895	395	226	53	6916
1985-86	0	26	259	509	1113	1610	1097	668	522	499	280	15	6607
1986-87	35	2	259	376	733	1141	1149	758	639	267	140	41	5563
1987-88	23	18	86	306	722	990	1195	780	686	359	261	59	5438
1988-89	4	5	157	178	724	1109	1242	1166	656	356	276	30	5963
1989-90	0	29	97	421	759	1064	951	858	633	303	286	82	5453
1990-91	6	10	26	430	710	1449	1253	651	676	493	306	100	6109
1991-92	0	0	55	409	822	1026	982	657	493	309	92	54	4897
1992-93	6	40	118	340	907	1134	1239	1004	715	501	140	155	6289
1993-94	53	45	124	367	960	975	993	839	570	378	148	64	5525
1994-95	9	1	34	440	967	1066							

COOLING DEGREE DAYS Base 65 deg. F BOISE, IDAHO

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1969	0	0	0	0	32	121	356	251	75	0	0	0	735
1970	0	0	0	0	24	201	357	341	50	0	0	0	953
1971	0	0	0	0	31	81	320	435	42	2	0	0	911
1972	0	0	0	0	62	129	283	303	40	0	0	0	817
1973	0	0	0	0	51	177	341	269	51	1	0	0	890
1974	0	0	0	0	13	251	319	226	71	0	0	0	851
1975	0	0	0	0	10	64	426	182	96	11	0	0	789
1976	0	0	0	0	19	66	263	190	55	2	0	0	595
1977	0	0	0	20	10	170	255	306	61	0	0	0	822
1978	0	0	1	0	6	64	254	205	72	0	0	0	597
1979	0	0	0	0	27	129	293	199	101	3	0	0	752
1980	0	0	0	3	25	69	258	117	38	2	0	0	504
1981	0	0	0	1	3	52	305	295	101	0	0	0	659
1982	0	0	0	0	2	117	194	248	50	0	0	0	611
1983	0	0	0	0	55	50	180	313	26	0	0	0	624
1984	0	0	0	0	19	70	291	340	64	2	0	0	786
1985	0	0	0	2	28	125	402	165	4	0	0	0	726
1986	0	0	0	1	103	235	164	346	57	0	0	0	905
1987	0	0	0	23	61	202	225	180	111	0	0	0	800
1988	0	0	0	0	46	237	308	215	65	24	0	0	896
1989	0	0	0	6	14	140	376	191	56	0	0	0	783
1990	0	0	0	3	5	145	357	293	180	6	0	0	989
1991	0	0	0	0	0	36	357	353	85	6	0	0	832
1992	0	0	0	11	76	202	208	321	77	20	0	0	915
1993	0	0	0	0	86	63	61	182	71	5	0	0	456
1994	0	0	0	15	30	156	386	354	96	0	0	0	1037

Source: National Oceanic and Atmospheric Administration

Table #3

#3

HEATING DEGREE DAYS Base 65 deg. F POCATELLO, IDAHO

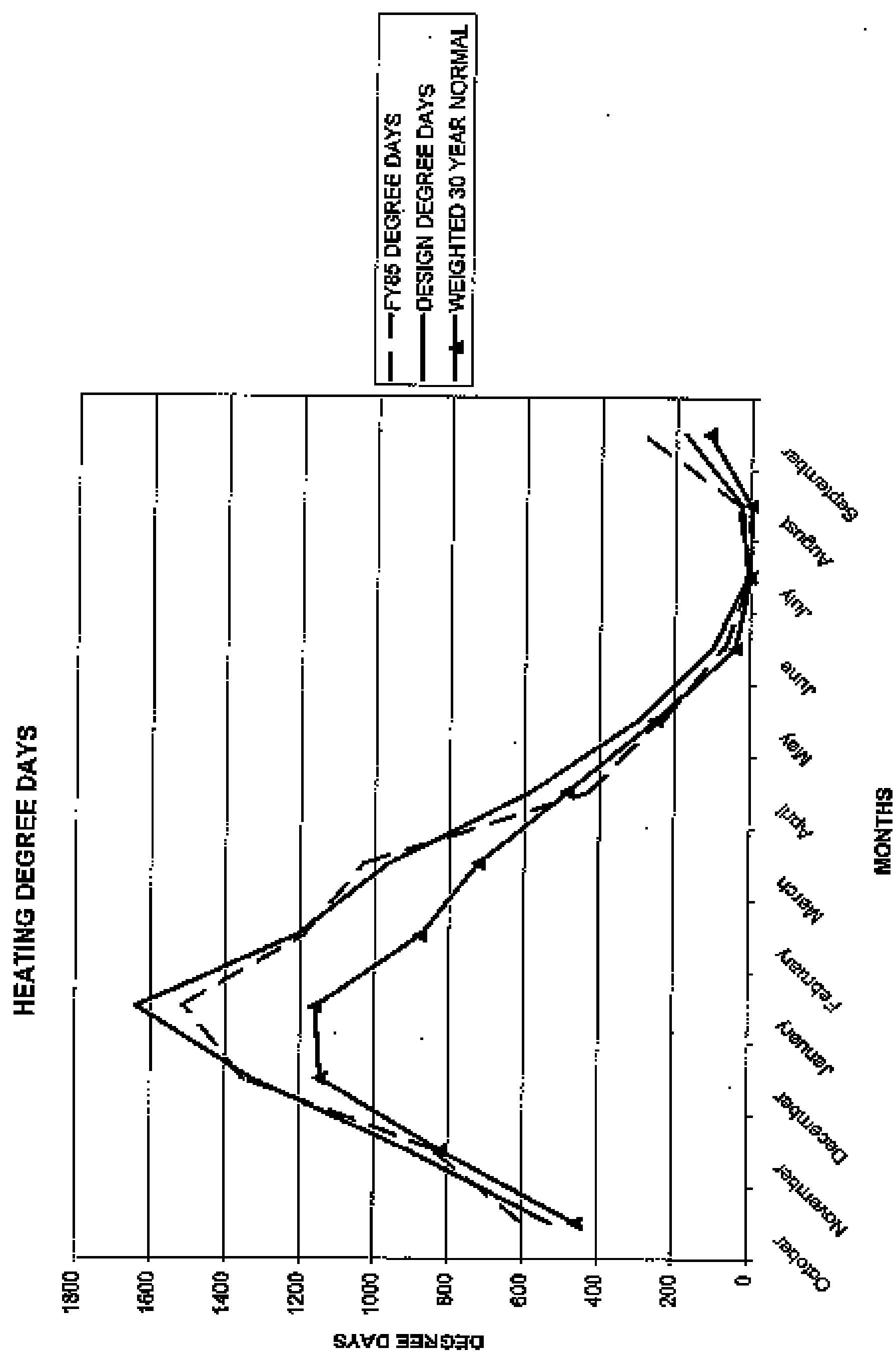
SEASON	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1965-66	10	60	393	440	725	1216	1211	1092	861	618	253	140	7005
1966-67	2	26	133	623	612	1263	1063	853	845	720	372	173	6946
1967-68	0	3	128	545	685	1398	1352	931	765	680	405	154	7271
1968-69	9	143	260	481	942	1240	1105	1094	1104	594	323	147	7462
1969-70	24	17	106	465	873	1124	1060	772	865	771	348	141	6833
1970-71	4	2	333	675	817	1236	1166	1014	997	666	376	163	7474
1971-72	19	13	374	664	964	1309	1300	1039	755	654	346	101	7538
1972-73	30	9	281	527	860	1445	1394	1057	895	643	290	135	7566
1973-74	12	18	237	500	843	1059	1313	979	815	560	359	78	6823
1974-75	11	42	173	500	639	1246	1312	1021	905	741	435	122	7144
1975-76	11	40	168	521	943	1001	1172	1026	999	615	219	140	6855
1976-77	1	34	163	561	611	1127	1475	1043	926	445	406	6	6981
1977-78	1	33	189	447	651	990	1045	675	678	567	431	119	6211
1978-79	10	39	241	473	900	1387	1675	1094	687	623	320	136	7857
1979-80	1	10	64	422	1020	1100	1245	676	683	507	415	154	6506
1980-81	5	37	182	576	839	1026	1125	938	801	516	407	127	6709
1981-82	16	9	130	603	800	1031	1352	1161	834	703	406	139	7234
1982-83	36	0	216	607	987	1227	1029	863	760	675	415	141	6955
1983-84	61	3	163	478	654	1392	1461	1291	949	654	335	205	7848
1984-85	5	7	221	643	697	1400	1612	1298	1157	472	246	85	8048
1985-86	0	44	321	597	1143	1657	1261	816	656	592	389	35	7513
1986-87	28	5	326	519	854	1247	1410	875	792	398	231	64	6739
1987-88	46	31	144	445	854	1309	1343	926	643	485	340	33	6703
1988-89	1	3	220	291	883	1330	1498	1292	820	449	365	113	7285
1989-90	0	47	159	556	831	1183	1079	1022	756	438	399	139	6609
1990-91	3	20	53	526	613	1555	1406	726	813	610	425	122	7138
1991-92	3	1	176	533	950	1185	1201	776	639	407	156	97	6135
1992-93	23	63	175	417	1078	1325	1445	1240	690	612	226	214	7727
1993-94	155	67	219	530	1115	1100	1006	999	704	492	207	90	6804
1994-95	17	5	100	539	1058	1208							

COOLING DEGREE DAYS Base 65 deg. F POCATELLO, IDAHO

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOT
1969	0	0	0	0	15	23	177	195	25	0	0	0	435
1970	0	0	0	0	0	91	197	230	4	0	0	0	522
1971	0	0	0	0	0	29	146	212	9	0	0	0	396
1972	0	0	0	0	7	26	150	152	6	0	0	0	341
1973	0	0	0	0	7	94	194	174	14	0	0	0	483
1974	0	0	0	0	1	130	215	102	12	0	0	0	460
1975	0	0	0	0	2	23	290	95	23	4	0	0	44[illegible]
1976	0	0	0	0	1	46	227	70	28	0	0	0	37[illegible]
1977	0	0	0	0	1	129	190	164	35	0	0	0	51[illegible]
1978	0	0	0	0	0	28	177	125	41	0	0	0	36[illegible]
1979	0	0	0	0	0	64	207	145	63	0	0	0	47[illegible]
1980	0	0	0	3	0	17	125	70	6	0	0	0	22[illegible]
1981	0	0	0	0	0	36	145	232	31	0	0	0	46[illegible]
1982	0	0	0	0	2	43	135	187	16	0	0	0	38[illegible]
1983	0	0	0	0	4	19	131	199	25	0	0	0	37[illegible]
1984	0	0	0	0	15	33	168	178	25	0	0	0	41[illegible]
1985	0	0	0	0	5	65	257	90	3	0	0	0	42[illegible]
1986	0	0	0	0	17	110	100	185	6	0	0	0	41[illegible]
1987	0	0	0	0	6	74	134	104	21	0	0	0	34[illegible]
1988	0	0	0	0	8	181	261	123	25	0	0	0	59[illegible]
1989	0	0	0	1	4	34	255	109	10	0	0	0	41[illegible]
1990	0	0	0	0	0	68	194	152	79	0	0	0	45[illegible]
1991	0	0	0	0	0	12	192	257	32	0	0	0	47[illegible]
1992	0	0	0	0	15	73	103	217	61	2	0	0	41[illegible]
1993	0	0	0	0	3	16	24	57	2	1	0	0	10[illegible]
1994	0	0	0	1	4	78	105	225	27	0	0	0	5[illegible]

Source: National Oceanic and Atmospheric Administration

HEATING DEGREE DAY



TRADITIONAL SUPPLY SIDE RESOURCES

Overview

Delivery of natural gas supply to end-use markets in the Pacific Northwest has evolved significantly in the past 15 years. Up until the mid 1980's, the typical gas Local Distribution Company ("LDC") or utility, merely “ordered” a certain quantity of natural gas each day from its local interstate pipeline company. The pipeline was responsible for contracting with producers for the natural gas supply, managing the daily gas supply and arranging for all required upstream pipeline capacity. Following a series of Orders from the Federal Energy Commission ("FERC") – armed with Congressional authority to introduce competitive market forces into the interstate natural gas marketplace – today’s LDC is responsible to structure, arrange and manage its own gas supply and transportation portfolio in order to meet the needs of its customers. Interstate pipelines are now only common-carrier transporters and no longer contract for gas supply to support sales service. If the LDC fails to properly plan to avoid supply failure, there is typically no other emergency or backup supplier; the LDC's end-use customers will presumably bear the consequences.

In today's competitive environment, the interstate pipeline grid and gas producing regions in the U.S. and Canada have become less localized as to the delivery function and are now a part of a larger, more integrated delivery system. For example, where much of the gas supply produced near the facilities of Northwest Pipeline Corp. ("NWP") was historically captive in the Pacific Northwest, new pipeline completions have created additional avenues for delivery into off-system regions from California to the Midwest. One result is an increase in overall pipeline grid efficiency as gas supplies can move quickly through once impassable capacity barriers, across vast regions to serve locations with the highest demands. While this new efficiency has led to new market growth for natural gas, it has lead to more competition among the Western and Midwestern U.S. markets for available gas supplies, driving up prices in the Northwest generally. Another more localized affect is a higher annual load factor on NWP resulting in less operational flexibility for shippers and less availability for long-term capacity release. This phenomenon has placed Intermountain in a mega-regional marketplace where market situations from Western Canada and California to the Gulf of Mexico or Chicago, may affect the local market dynamics relating to supply availability, pipeline capacity and commodity pricing signals.

While the gas delivery environment has changed drastically in the past decade, Intermountain's commitment to providing secure, reliable and price-competitive firm service to its customers has not. Whether the customer desires burner-tip sales service, transport-only service or other unbundled service options, Intermountain will, through its long-term planning process, continue to identify, analyze and utilize best-practice strategies and implement procedures necessary to provide the value of service that its customers expect. This Supply Resources section will identify and discuss each of the available supply resources and describe how each part may be utilized in a larger portfolio approach to gas delivery management.

It should be noted that even though gas molecules themselves are the commodity normally referred to when discussing gas supply, natural gas at a given supply point may have little value unless a sufficient amount of transport capacity is also available to effectuate delivery to the burnertip. Alternatively, a party with firm transport capacity could find itself unable to use the capacity unless adequate gas supply is available at the proper location(s) where the pipeline will receive it and deliver it to the market. Consequently, natural gas supply and transport capacity must be utilized together (hereafter referred to as "Delivered Supply") to deliver natural gas to an end-use market’s burnertip. Clearly, possession of one without the other will in all probability result in less than firm service and in all likelihood, increases the risk of supply failure.

Background/Historical Perspective

The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its original geological source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Intermountain physically receives all gas supply to its distribution system via taps with NWP, the only interstate pipeline with interconnects to Intermountain's system. A predecessor of NWP first brought natural gas service to the Pacific Northwest in the mid 1950's by constructing pipeline facilities which began in Northwestern New Mexico and Southwestern Colorado and continued Northward through Utah into Southern Idaho, then across Idaho, Eastern Oregon and Western Washington. The pipeline then continued Northward up the I-5 corridor where it interconnected with Westcoast Transmission ("Westcoast"), a Canadian pipeline in British Columbia, near Sumas, Washington (See Exhibit 4, Appendix 1). Along its path, NWP also interconnects with PG&E NW near Stanfield, OR as well as several other interstate and gathering systems in Wyoming, Utah, Colorado and New Mexico. From those interconnects, Northwest receives gas supplies from the gas producing regions in British Columbia, Alberta and the Rocky Mountain region of the Western U.S. for delivery to utilities and other end-use customers located both on and off its system.

Before the introduction of deregulation policy, FERC strictly regulated all aspects of the interstate gas delivery system including wellhead pricing, transport capacity, storage utilization and delivered-to-the-citygate pipeline prices. Consequently, prior to "Open Access", Intermountain simply reserved peak day delivered requirements from NWP, "nominated" the level of expected demand for any given gas day, and paid NWP the tariff price for the level of bundled services utilized. There existed no way for Intermountain to negotiate better prices, adjust its portfolio to meet changing market conditions or temporarily sell off under-utilized "resources".

Under this strictly controlled and regulated environment, the natural gas industry in the late 1970's and early 1980's began to experience a decline in overall demand, particularly in the industrial market segment, as the enduse market responded to gas prices which were artificially high vis-à-vis other energy alternatives. At the same time, FERC's practice of setting high wellhead prices to ensure adequate levels of reserve replacement discouraged producers from efficiently managing production and deliverability. High prices encouraged producers to continue to add to the growing supply surplus even though, in reality, no market existed for gas at the regulated prices set by FERC. Additionally, when excess demand did occur during peak periods, no mechanism (i.e. a spot market) existed to move this surplus, uncontracted supply to end-use markets resulting in curtailments that were interpreted by the market as supply shortages. This mixed bag of confusing economic signals was one of the key factors that led the Federal government to determine that only a free and competitive marketplace could solve the problems then facing the gas industry. Exhibit 4, Table 1 lists and describes some of the more significant legislative actions and events which led to decontrol and deregulation of the gas industry, as well as several of the ensuing FERC Orders by which these policy directives and laws were implemented. The most recent of these Orders was No. 636 issued in 1992.

Order 636 generally completed the task of providing a more open and competitive marketplace by unbundling pipelines' gas purchasing obligation from their transportation function. As a result, pipelines became common carrier transporters and any party could have access to available space through a capacity release mechanism. All shippers were compelled to provide their own supply and any shipper with unneeded capacity could release it in the open market via the pipeline's electronic bulletin boards ("EBB") or websites. Other significant features of Order 636 were Straight-Fixed-Variable ("SFV") rate design, open market access to storage and Hub services, flexible receipt and delivery point nominations and the shifting of system balancing responsibility from the pipeline to the shippers and other end-use customers.

Intermountain's gas supply management strategy involves meeting all firm customer gas and/or transportation requirements while minimizing costs and associated risk by utilizing a portfolio of diverse supply resource options. Supply resource options include natural gas supply, transportation capacity (both interstate and distribution) and storage facilities as well as non-traditional supply sources discussed in Non-Traditional Rresources.

Gas Supply

General. Intermountain is well positioned in a region with a diverse and stable supply base as the Rockies and Western Canadian producing fields continue to provide ample production and deliverability. With recent successful reserve finds in the Alberta, BC and the Rockies producing basins, gas supply availability should be adequate throughout the forecast. Recent evidence would indicate however, that the traditional gas bubble of excess supply is no longer a reality. While the unprecedented price increases during 2000 and 2001 were the result of many factors, clearly overall demand growth has exceeded supply growth over the latter part of the 1990's. It is also apparent that the exploration and drilling community can bring additional supplies to market quickly if prices are high enough to encourage adequate investment.

A recent Canadian National Energy Board (NEB) study projected that 271 Tcf is recoverable from the Western Canadian Sedimentary Basin – a 50-year supply at current rates of production. However, other studies indicate that over the medium term, producing entities' plans for drilling and production may not replace natural declines in production, particularly in Alberta. New gas finds in Northern British Columbia and the Northwest Territories indicate significant potential supply pools as does the recent activity in the Glendale formation in Northwestern Alberta. As well, interest has again peaked in the supply potential from the Arctic regions of Alaska and Canada in the Prudhoe Bay and Mackenzie Delta region although significant investment in pipeline capacity would need to be addressed. Forecast production figures for domestically produced gas are more difficult to obtain. However, projections indicate that free-market competition continues to spur future exploration and new technologies in the Rocky Mountain regions, ensuring ample gas production well into the future.

A significant change in most forecasts show increased pricing for the Pacific Northwest reflecting new pipeline capacity in the Western U.S. and Canada which allow more gas supply to flow to the historically higher priced markets in the Midwest and East coast. While prices are projected to increase and remain robust, availability is not expected to be an issue. Even during the high prices of 2000 and 2001, gas was available as long as a market was willing to pay the market price. As well, issues relating to gas-fired generation, storage, hydro-generation and gas-to-electric price spreads that plagued the market during the past few years appear to be less critical as the competitive market adjusts for these factors.

Types and Pricing. During the early years of Open Access, Intermountain determined that a portfolio based on firm supply contracts with a variety of reputable suppliers would provide the greatest level of reliability and security for year-round delivery of gas supply. Firm supply (as opposed to best efforts or interruptible) is sold with a supplier's assurance that, absent a defined *force majeure* event, 100% of the supply will be available for delivery to the market on every day of the contract term. While this is still true, Intermountain's previous reliance on longer-term contracts (supply with contractual term of one or more years) for the majority of its portfolio has lessened. The acceptance of the NYMEX natural gas contract and/or associated derivative pricing as the industry pricing standard, has allowed Intermountain more flexibility in the way it builds the portfolio. The reliability requirements in NYMEX based purchase contracts has allowed Intermountain to place less emphasis upon the longer-term contracts while still basing the purchases on firm supply. As well, stringent creditworthiness requirements, by financial institutions, give buyers and sellers more confidence as to the financial viability of their contractual counterparties, notwithstanding of length of the contracts. Because buyers and sellers are generally unwilling to take unnecessary price risk, the amount of gas whose price is based on NYMEX-type financial instruments continues to account for the majority of supply of traded.

One key element of term supply pricing is Load Factor. Load Factor is simply the average daily usage over a period divided by the maximum available during the period or alternatively, the peak usage. A producer is typically more willing to offer supply under a high load factor contact. In fact, it has become increasingly difficult to purchase firm supply at anything other than 100% load factor. Under a 100% load factor contract, the supplier knows that absent any force majeure event, the market will take the full volume of gas every day during the term of the contract. Alternatively, under a less than 100% load factor contract, the market may only take gas during the peak periods and release the supply to the supplier during lower usage periods when pricing is usually less advantageous for the seller. Therefore, the supplier must stand prepared to re-market the unutilized supply when the term market does not require it - often times at short notice and during periods when spot pricing is relatively low. For this reason, suppliers usually require a premium to the market price or a demand charge when contracting with low load factor markets. The load factor concept is an important part of portfolio management and will be discussed more in depth in a later section. Intermountain also utilizes other types of supply such as daily and/or monthly spot, seasonal supply, swing and winter peaking. The company's use of storage facilities to balance loads also helps to level out supply takes (See Page 41, "Storage").

Long-term supply has historically been priced at a premium to spot or index-based supply, so it is imperative that term supply contracts have flexible pricing terms (e.g. annual renegotiation or index based provisions) in order to remain market competitive.

Spot gas is typically gas that suppliers, for various reasons, do not contact on a term delivery basis. The term "spot gas" may apply to gas sold under differing terms including firm, interruptible, swing, day gas or best efforts and is usually available at almost anytime at varying volumes, prices and contract terms. Spot gas may be bought for one or several days a time, for one month or even for seasonal periods such as the summer injection periods. During peak usage periods, spot may be difficult to find, be relatively expensive, unreliable or may be available only on a day-to-day basis. Of course in non-peak months, spot is most often readily found and is usually relatively inexpensive compared to firm supply. Intermountain generally purchases firm spot supplies for a given month and as a rule, targets those suppliers with reputation for reliability.

Swing supply is gas that is very interruptible. Swing is most often utilized early in the winter periods in order to preserve storage or during times when the loss of that supply would not result in curtailments to customers. Swing is most often available during significant weather swings and is often the cheapest gas that can be purchased due to its interruptible nature, but it can play an important role in a diversified portfolio.

Winter peaking supply is typically baseload volume purchased for the two-to-four winter peak usage months to augment the storage withdrawal cycle. While these contracts may be structured in any number of ways, they are ordinarily firm in nature and have 100% daily take commitments but often have price levels that exceed month-to-month spot. If Intermountain's loads continue to grow and new storage resources are not contracted for, the medium term forecast may include a higher level of this type of contract in order to fortify the reliability of winter deliveries.

Supply Regions. Intermountain's natural gas supplies are located primarily in three producing regions: British Columbia (BC) Canada, Alberta, Canada and the Rocky Mountain (or Domestic) region consisting of production primarily from the states of Wyoming, Utah, Colorado and New Mexico. In general, the proportion of purchases from the various supply basins is very dependent upon firm receipt capacity on the pipelines (see “Transportation”).

British Columbia. BC has traditionally been a source of inexpensive and abundant gas for the Pacific Northwest as much of the gas produced in the province is exported into the U.S. at an international interconnect point located near Sumas WA. Much of that supply had historically been somewhat captive to the region due to the lack of alternative pipeline options into Eastern Canada or the Midwest U.S. However, the expansion of TransCanada Pipeline’s capacity into Eastern Canada and the completion of the Alliance pipeline delivering supply into the Chicago area, eliminated that bottleneck. While there continues to be an adequate supply from BC over and above provincial demand, new discoveries in Northeast BC and the Northwest Territories are critical to future deliverability to export markets. Even though these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to encumber the delivery to Intermountain's citygates.

As a condition of sales CD conversion, NWP required that shippers continue to source purchases in the same proportion that the pipeline had sourced its sales portfolio: approximately 58 percent of daily supply had to be sourced from Sumas to ensure the efficient operations of the pipeline. However, past experience with NWP system dynamics has shown that any type of disruption due to normal maintenance, extreme weather conditions or basin price variations, tend to result in pro-rata transport cuts and Operational Flow requirements. The operational dissonance is particularly onerous and most often occurs with South-flow supply from Sumas through the I-5 corridor. Intermountain actively searched for ways to minimize these problems. One alternative was to move existing receipt capacity or find new capacity at alternative points. Intermountain also discovered there were certain transportation cost benefits to moving firm receipt capacity away from Sumas. Consequently, Intermountain elected to “segment”, or move just over half of its firm receipt capacity on Northwest from Sumas to Stanfield (See Page 40, “Transportation”). This reduced its reliance on the amount of BC supply purchased, from 58 percent of peak purchases in the late 1980’s, to approximately 22 percent today and added a new level of diversity to the gas supply portfolio.

Recent deliverability studies by Westcoast showing robust future production as well as plans to expand pipeline capacity to Sumas indicate that future supply availability in BC should continue to increase.

Alberta. Production in this province has always been abundant. In fact, Alberta is believed to have the largest natural gas reserves in the North American continent and annually produces 10 times the Pacific Northwest’s yearly consumption. Since a 1993 PGT (PG&E NW) expansion that increased the delivery of Alberta supply into NWP, Alberta supply has greatly increased in importance within Intermountain's portfolio. The Stanfield interconnect between NWP and PGT offers added operational reliability and flexibility over other receipts points both north and south. Other positive factors influencing the decision to purchase Alberta supplies are vast unrecovered reserves, extensive pipeline facilities, and access to inexpensive production-based storage (see "Storage"). Where these supplies once amounted to a trickle, today’s purchases amount to approximately 36 percent of the company's daily supply.

One area of concern is the rapid production decline of wells drilled in the past few years. In response to the price increases in 2000 and 2001, record numbers of rigs were drilling in Alberta. A large number of these new well completions were in shallow reservoirs which produced huge levels of natural gas early on, but then declined rapidly. However, regions that are expected to be the next frontier for future exploration and production are in basins requiring deeper well depths. These deeper wells generally do not have the robust early production of the shallower wells but neither do they have the steep production decline curve and therefore produce gas, at steadier rates, for much longer periods. So, while the short-run supply availability from Alberta may tighten somewhat, longer-term forecasts project ample production. Additionally, the northern most pipeline facilities in Alberta are well positioned to receive supply from the Arctic regions should exploration and production commence in those basins.

Domestic (Rocky Mountain). Domestic supply has historically been the second largest source of supply for Intermountain partly due to NWP requirements (see "Transportation") but also because the supplies have been readily available, relatively inexpensive and highly reliable. Events such as NWP's expansions at interconnects with off-system pipelines (e.g. Kern River) and the general effect of the deregulated and competitive marketplace has tended to make supply in this region more price competitive with Midwestern and California markets and consequently, more expensive than in the past.

One area of concern is the NWP capacity constraint at Kemmerer, Wyoming (just East of the Idaho border) which limits the amount of domestic supply that can flow west into Idaho during peak periods. Taking advantage of “segmentation” opportunities on NWP, the company increased its allocation of firm capacity rights from receipt domestic points flowing through the Kemmerer bottleneck into Idaho. This provided Intermountain with the capacity necessary to transport Clay Basin withdrawals into Idaho. Because the cost of physically increasing capacity through the Kemmerer constraint point would be exorbitant, the company will likely not increase its stake in domestic supply unless additional released capacity can be obtained through another firm shipper on NWP. Though future growth in domestic supply will likely increase, the company will continue to obtain approximately 42 percent of its peak gas supply from the Rockies. (See Exhibit No. 5, Appendix B for Supply Resource Summary.)

Transportation

General. All activity regarding transportation of natural gas supplies through any part of the interstate pipeline grid continues to be under the review and regulatory oversight of the Federal Energy Regulatory Commission (FERC). Through a series of regulatory orders, such as Orders 400, 436, 500 and finally 636, the FERC led the natural gas industry into a more competitive environment by first decontrolling wellhead natural gas prices and then by deregulating and unbundling interstate transportation capacity. As the final step in the deregulation process, pipelines were required to discontinue purchasing natural gas and, consequently eliminate all sales service. The pipelines' former sales customers were directed to convert their sales entitlements to firm transport capacity.

Prior to this action by FERC, Intermountain fully believed that FERC would eventually implement 100% decoupling of supply from transportation, that taking full advantage of this new transportation was a great opportunity to benefit all of its customers. Consequently, in 1988 Intermountain took full advantage of the option to voluntarily shift from sales to transportation service and was the first Pacific Northwest LDC to convert 100% of its applicable sales CD to transport capacity. Intermountain was also the first LDC in the Northwest to implement transportation tariffs behind its own citygate in order to allow its industrial customers to enjoy the advantage of open access transportation. FERC Order 636, issued in 1993, was the final step in the unbundling process and essentially compelled every firm customer to purchase and transport 100% of their own supply. When NWP implemented Order 636 on its system in 1994, Intermountain had already been transporting 100% of its supply for six years.

Another important feature of Order 636 allowed firm shippers to "release" unutilized capacity to others in the marketplace who would pay to lease it for some predetermined period of time. This allows Intermountain to sell off unused capacity in off-peak and also to obtain additional capacity if the need were to arise. A valuable offshoot of capacity release is the notion of "segmentation". This is particular kind of release where the primary path can be divided into two or more separate pieces where each piece still retains its applicable primary firm rights. Then one or more of the pieces may be released to a replacement shipper. The amount the replacement shipper pays for the "new" capacity is a cost savings to the releasing, or original, shipper. Intermountain has completed several long-term segmented releases that enable to company to retain the same level of overall firm capacity while also obtaining a significant cost saving which can be passed on to customers.

In general, firm capacity provides for the reservation by the pipeline on behalf of designated shippers, of certain rights to receive and deliver gas supplies on that pipeline system. The major pipelines with which NWP interconnects can be seen on Exhibit 4, Appendix 1. Westcoast Transmission in British Columbia interconnects with NWP near Sumas, Washington and provides for the receipt of supplies produced in that province. An interconnect with PG&E NW (formerly PGT) near Stanfield, Oregon allows for the delivery of gas produced in Alberta into NWP. Other major interconnects are with Colorado Interstate Gas in Southwestern Wyoming; Questar Pipeline in Western Colorado and Eastern Utah; and El Paso Pipeline in Southwestern Colorado and Northern New Mexico. These pipelines provide outlets for gas produced in locations stretching from Wyoming to New Mexico. NWP also directly interconnects with producing and/or gathering areas in Wyoming, Utah, Colorado and New Mexico.

Intermountain's receipt point capacity from each major region at selected points on NWP can be seen on Exhibit 4, Table 2. Under the terms of the company's voluntary conversion in 1988, NWP required that all converted CD receipt point capacity be prorated as 58% Sumas and 42% domestic. Subsequently, Intermountain participated in NWP's Phase I expansion and contracted for additional firm capacity from both Sumas and domestic points (See Exhibit 4, Appendix C).

Shortly thereafter, the company determined that with the extreme customer growth occurring in this service territory, it would participate in NWP's phase II expansion projected to be in service beginning November 1995. The anticipated incremental requirement was 800,000 therms at various receipt points across the system. Because of the risk of incremental price design (which would cause the new capacity to be nearly three times as expensive as the then current capacity), the company subsequently exercised a termination option from the expansion. Capacity Release - made possible by Order 636 - was then utilized to replace the most of Phase II capacity by obtaining capacity excess to other firm shippers holding rights on the system. Intermountain replaced these volumes at prices no higher than the then current transport cost and in fact, a significant portion of the capacity was obtained at prices less than full rate. Another consequence of the Phase II replacement was the significant shifting of receipt point capacity from Sumas to Stanfield. However, the overall 58% Canadian and 42% domestic receipt point allocation was maintained.

The Company utilizes this transport capacity to move purchased supplies to the citygate taps with NWP. Gas is then moved from these various points through its own distribution system to provide various types of delivery service to its customers. Residential and small commercial ("Core") customers and currently may receive only sales service while the smaller of the large volume industrial customers may also elect the same.

Intermountain provides both interstate and distribution transport services to its industrial customers in its service territory through the use of its pipeline contracts and/or distribution system. For Intermountain's firm T-1 and T-2 customers, the customer's gas is received at the NWP mainline, transported on the Company's interstate capacity and distribution system and then redelivered to the customers' facilities. The Company also transports gas under its T-4 tariff where the customer delivers supply to one of Intermountain's applicable citygates and that supply is then redelivered to the customer's facilities via the Company's distribution facilities.

Intermountain has actively managed the utilization of its transport capacity through the growth years of the 1990's as projects to build new capacity have largely been either extremely expensive or unavailable to this area requiring the company to consider several alternatives. In fact, NWP has no current plans for facilities expansion that would provide additional rights to Intermountain. One strategy to forestall the need to purchases new capacity has been to encourage the Company's industrial customers to participate in the open market to procure their own capacity. The Company has also limited growth in the industrial customer's loads under firm agreements and has required new transporters to elect T-4 distribution-only transportation service. These strategies have allowed the company to continue to serve the core market with firm service without adding new pipeline capacity. Intermountain recognizes that eventually growth will dictate the need for additional capacity; projections for adding new capacity are addressed in this study.

The company has one main transmission line in Eastern Idaho that serves customers in the Idaho Falls region. Due to increased customer load in this area, this line has been capacity constrained at times and is one of the resources that the company monitors closely. Intermountain has also recently identified two other locales that are projected to see capacity constraints in the coming years. The first is the Sun Valley lateral in Central Idaho and the Canyon County area in Western Idaho. All three of these constraint areas are addressed in this study.

Storage Resources

General. Because of the steep load shape of the Company's LDC, peak demand greatly exceeds maximum supply deliverability as the cost to obtain enough transport capacity to supply the peak day would be enormous. To fill this gap between peak demand and available deliverable supply, storage facilities are utilized. Intermountain injects gas into storage during off-peak periods and then withdraws it during the peak load months. The advantage is two-fold: first, the Company can shave the winter peak off the LDC minimizing transport capacity needs and secondly, injecting gas in off-peak months provides a more efficient year-round of the interstate capacity resource. Additionally, the market normally prices off-peak supplies at a discount allowing the Company to lower its overall WACOG. Storage facilities are normally of two general types: liquefied storage and underground storage.

Liquefied Storage. Liquefied storage facilities make use of a process that pressurizes and supercools gaseous methane to approximately minus 260 degrees Fahrenheit until it liquefies. Liquefied natural gas

("LNG") occupies only one-sixhundredth the volume compared to its gaseous state and so it is an efficient method for storing peak requirements. However, the liquefaction process is an expensive process and since these facilities are man-made, the use of large steel tanks, safety equipment and costly compression equipment are required. It typically requires as much as one unit used for liquefaction fuel for every three to four units liquefied. Also, the liquefaction cycle may take 5 – 6 months to complete. Because of the high cost and length of time involved filling a typical LNG facility, it would normally be cycled only once per year and its use reserved for peaking purposes.

However, the process of changing the liquid back into the gaseous state is an efficient process called vaporization. Since the natural state of methane under typical atmospheric and temperature conditions is gaseous and in fact, lighter than air, and the liquid methane is super-compressed, vaporization requires little energy and will occur naturally under normal conditions. Vaporization of LNG into a system is usually accomplished by utilizing the system pressure differentials through the opening and closing of valves. The high pressure LNG is allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and a typical withdrawal cycle may last less than 10 days at full rate. For this reason, LNG is typically used as "needle" peaking supply and is usually located in market areas.

Intermountain utilizes two such facilities; one is NWP's LS facility located near Plymouth Washington and the other resides on Intermountain's distribution system near Boise. Neither facility requires the use of existing transportation capacity as the Plymouth facility has bundled transport capacity for delivery to Intermountain and the LNG tank withdrawals go directly into the Company's distribution system. Exhibit 4, Table 3**,** summarizes the capacity and withdrawal statistics for all of the storage facilities utilized by Intermountain.

Underground Storage. This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities often require little hardware compared to LNG and are usually less expensive to build per equivalent volume. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. These lower costs allow the more frequent cycling of inventory; many such entities are utilized to take arbitrage changing market prices. Of more significance to Intermountain, the minimal commodity costs make underground storage an ideal tool for winter baseload or for daily load balancing.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, daily injection levels are much higher while daily withdrawal maximums are significantly less. Consequently, a typical withdrawal cycle might last 35 days or more at maximum withdrawal. For this reason, the company generally utilizes underground storage for winter baseload supply; the withdrawal cycle typically lasts from November to mid-March.

Intermountain utilizes three underground storage facilities. The first is Jackson Prairie located near Chehalis, WA and operated by NWP. Another is Questar's Clay Basin facility Northeastern Utah that has a direct connection to NWP. Lastly, the company utilizes a facility located in Eastern Alberta called "AECO" operated by the Alberta Energy Company. It is connected to the NOVA system and, unlike the other storage sites used by the company which are market based, AECO is located near the producing fields of Alberta and does not require the use of Intermountain's interstate capacity to effectuate injections.

Delivery Capacity. Both the Plymouth and Jackson Prairie facilities include distinct bundled firm redelivery transport capacity on NWP equal to the daily the withdrawal rights. This enables Intermountain to withdraw and redeliver these volumes without using its annualized firm capacity; however, injections do require the use of interstate capacity. This is advantageous because allows the company to minimize its daily, or annualized maximum requirement during peak seasons but also provides a mechanism whereby the Company can use otherwise unutilized capacity during the non-peak season.

AECO and Clay Basin are not bundled with transport redelivery capacity. This requires Intermountain to use its already existing annualized capacity on NWP to move withdrawals to the company's citygate locations. As such, these facilities' inventory is generally withdrawn in a winter baseload fashion. Clay Basin also requires existing capacity for injections, while AECO does not. The LNG facility only requires capacity for injections since it is located on the company's own system; withdrawals generally occur via pressure differentials and are reserved for the coldest peak periods.

Summary. The company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lessor extent, for system balancing. Intermountain believes that the geographic and operational diversity of the five facilities utilized offers the company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the company flexibility to determine its best use from alternative such as winter baseload, peak protection, price arbitrage or system balancing. Because of high levels of daily withdrawal capacity along with relatively high operating costs, the Company has traditionally used the liquefied inventory facilities (LS and LNG) for needle peaking supply during periods of extreme cold.

Supply Resources Summary

Intermountain utilizes an efficient mix of the above supply resources to provide reliable, secure, and economic firm service to its customers. The Company is continually reviewing the varying needs of its customer base as well as the changing environment in which it operates. Intermountain actively manages its current mix of resources and is consistently seeking additional resources and techniques to maintain and improve service to its customers. The Company actively monitors natural gas pricing and production trends in order to maintain a secure reliable and price competitive portfolio. Intermountain also seeks innovative techniques to manage its transportation and storage assets in order to provide both economic benefits to the customers and operational efficiencies to its interstate and distribution assets.

NON-TRADITIONAL RESOURCES

Non-traditional resources are defined here as providing additional resources to meet the design peak day load by either decreasing the gas load using alternative fuels or increasing capacity within the existing distribution system. Five (5) such non-traditional resource alternatives were considered and are as follows:

- #2 Fuel Oil
- Propane
- Propane-Air
- LNG Facilities
- Compressor Station

#2 Fuel oil, propane and propane-air were evaluated as alternative fuels used in conjunction with industrial customers and could be considered forms of Demand Side Management since the industrial customer's gas load in essence is being reduced during peak day demand.

Since LNG facilities and compressor stations are considered additional facilities added to the existing distribution system to increase capacity, the addition of such facilities could be considered another source of needle peaking gas supply, or a form of Supply Side Resource. Propane-air could also be considered as a form of Supply Side Resource due to the injection of a propane-air mixture into the distribution system.

#2 Fuel Oil

A contributor to IGC's system needle peak are the large volume industrial customers. Large volume industrial customers typically purchase their own firm gas supply and contract with IGC for the use of firm pipeline transportation capacity. Utilizing #2 fuel oil is restricted mainly to the industrial customers because of the equipment typically used within industrial plants, i.e. boilers. Switching the boiler load over to oil and leaving the direct fire load on gas during peak demand typically reduces the plant as load by 60-80%. During the peak day sendout, an industrial customer may have the ability to switch to the #2 fuel oil, thus lowering the demand on the overall firm transportation capacity.

Capital costs for #2 fuel oil facilities are approximately $150,000 - $200,000 providing 27,800 therms per peak day sendout for eight days. After the eight days, the facilities would then have to be refilled with oil at a cost of $0.90 per gallon, or $0.65 per therm [Note: One gallon of #2 fuel oil is approximately 139,000 BTUs]. Fixed operation and maintenance (O&M) costs are approximately $50,000-$100,000 per year.

Propane

Since propane is similar to natural gas, the conversion to propane is much easier than a conversion to oil. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce the industrial plant gas load by 100%.

Capital costs for propane facilities are considerably higher than that for #2 fuel oil. Typical capital costs for a peak day send out of 30,000 therms per day are approximately $525,000. Such peak day send out is limited to six days after which the facilities would have to be refilled with propane at a cost of approximately $0.50 per gallon, or $0.54 per therm [NOTE: One gallon of propane is approximately 92,000 BTUs]. Fixed O&M costs are approximately $50,000 per year.

Propane-Air

Propane-air facilities were evaluated with the potential of utilizing such facilities in both reducing the large volume industrial customer load and providing additional supply or capacity to the core market load within the existing distribution system.

Propane-air facilities used as an alternative fuel within industrial plants to reduce the peak is basically the same as propane, with the exception of even higher capital costs. Such capital costs are approximately $560,000 for the same peak day sendout of 30,000 therms with fixed O&M costs of approximately $100,000 per year.

Using propane-air facilities to provide additional supply to the market area to meet the peak day requirements was also evaluated. The same capital and O&M costs would be incurred as with an industrial customer, but typically additional property and siting requirements would be required to locate the propane-air facility near a distribution system. There are several interchangeability concerns brought about by too great a concentration of propane-air when blended with natural gas, all of which can pose service, maintenance and safety problems with unattended appliances.

LNG Facilities

Portable LNG facilities are available for lease from various companies and could be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG plants and are dependent upon actual location of the portable LNG facilities. The available delivery pressure from the facilities is limited to a maximum of approximately 250 psig with a peak day sendout of approximately 24,000 th/day per vaporizer. Fixed costs with one vaporizer and two days of storage, regardless of any LNG usage, is approximately $150,000 for a three month period. The actual cost of LNG is dependent upon usage, natural gas prices, liquefaction and transportation costs.

Compressor Stations

Compressor stations are typically installed on pipelines or laterals operating at higher pressures and having a fairly significant gas flow. IGC currently has only two such pipelines (Sun Valley Lateral and Idaho Falls Lateral) on which the installation of a compressor station would be practical. Regulatory and environmental approvals would be significant while engineering and construction costs for a compressor station capable of providing a 100,000-200,000 therm per day increase in capacity is approximately $2,500,000. Fixed O&M costs are approximately $100,000 per year.

DISTRIBUTION SYSTEM MODELING

Gas flow through a pipe falls under the engineering discipline of fluid mechanics. Due to the nature of fluid flow, there is a finite amount of gas that can flow through a pipe of a certain size and length. Engineers in the field of gas distribution can use the laws of fluid mechanics to approximate flow conditions of gas through pipes. Ultimately, it is total throughput, or system capacity that is desired to be known during peak demand.

Gas distribution networks, or systems, rely on pressure differentials to move gas from one place to another. If the pressure is exactly the same on both ends of a particular system, gas will not flow. When gas is removed from some point on a system (i.e. regulator station, house meter, industrial customer) to get to an appliance or boiler, the pressure in the system at that point is then lower than the pressure upstream in the system. This pressure differential causes gas to move from the higher pressure point to the point of removal in order to equalize the pressure throughout the system. The same principle keeps gas moving from the interstate transmission lines to the local distribution company's distribution system to the residential meters and ultimately to the appliances inside the homes. Therefore, it is important that gas engineers design a distribution system in which the beginning pressure (from regulator stations) within the system is high enough so that a feasible and practical pressure differential is created when gas leaves the system.

When the total load exceeds the system capacity, the pressure at the far end of the system becomes zero and the system basically runs out of pressure. Using the laws of fluid mechanics, engineers determine the maximum flow of gas through a distribution system of various pipe diameters and lengths that will not cause significant pressure drops. This process is known as "distribution system modeling."

The modeling process is important because it allows the engineer to determine the capacity of various distribution systems. For example, if a large usage customer were added to a distribution system, the engineer must evaluate the existing system and then determine whether or not there was adequate capacity to maintain the new customer along with the existing customers. Modeling is also important when planning new distribution systems. The correct size main pipes must be installed to allow for the flow needed to meet the requirements of current customers and reasonably anticipated future customers. Also, existing system capacities can be evaluated using the model, by gradually increasing the loads throughout the system until the pressure loss with the system becomes unacceptable.

Modeling by Town

In December, 1992, IGC purchased a gas network analysis software program from Stoner Associates allowing the engineer to model all sizes of distribution systems. The software program was chosen for its reliability, versatility and power. Using the software, individual models are created for each of IGC's various distribution systems, including high pressure laterals, intermediate pressure systems and distribution system networks.

The model of the various systems is constructed as a group of nodes and elements. A node is defined in a system as being a point where gas either enters or leaves the system, change in pipe diameter or the connection of pipe. An example of a node in a distribution system might be a number of homes within a subdivision, a small commercial load, or a large industrial load. An element is defined in a system as the various sizes of pipe, regulator stations or compressor stations, which make up a distribution system. A model for a small sized town typically consists of approximately 100 - 300 nodes and 250 elements, a medium size town typically consists of 500 - 1500 nodes and 1200 elements and a large city or area typically consists of 4,000 or more nodes and 4,000 or more elements.

The software program allows the engineer to input and/or change the gas load at an individual node, some or all nodes. By using the forecasted loads within this integrated resource plan, IGC engineers can determine anticipated future constraint areas based on the calculated pressure drops. When constraint areas are found, the engineer determines the most practical and cost effective method of solving the problem. Sometimes the solution is as simple as increasing pressure within the system, but in most situations additional pipe, or looping is required. Looping scenarios can then be modeled to determine the ultimate size and location of pipe in order to maintain adequate pressures throughout the system.

THE EFFICIENT USE OF NATURAL GAS

In the United States, natural gas currently meets 25% of the nation's energy needs, heating most American homes, and providing needed energy to manufacturing plants, commercial businesses, and most new electric power plants. Demand for this highly efficient fuel is expected to grow in the nation by 50% in the next 20 years.

Natural gas is the cleanest-burning, most efficient fossil fuel. That's why the Sierra Club, the Natural Resources Defense Council and others view natural gas as the ideal "bridge" between today's energy mix and future increased use of renewable forms of energy as they become technically and commercially feasible.

NATURAL GAS EQUIPMENT EFFICIENCY

American ingenuity has yielded exciting ways to meet energy needs without sacrificing the environment. Over the recent years, new natural gas residential and commercial HVAC equipment and appliances have become far more efficient as Federal and State equipment efficiency standards have taken effect. And within the existing customers, as old, less-efficient equipment wears out, it's replaced with these newer, more efficient units. Thus, the entire natural gas user base in Idaho grows more efficient each year.

Through the adoption of more energy efficient building codes and standards, new homes and commercial structures are built to higher standards, driven by Federal and State codes, which has meant far more efficient use of natural gas. And as with the replacement of older equipment mentioned above, older housing and commercial units are being upgraded to higher efficiency standards.

Intermountain Gas Company ("IGC") has a long history of promoting the efficient use of natural gas by our customers. Over the years, IGC has offered rebates and incentives for the installation of energy saving devices such as pilotless furnace ignition systems, furnace flue dampers, and to this day, a high-efficiency furnace rebate.

IGC is currently preparing a spring/summer conversion promotion along with Wells Fargo Bank. Wells Fargo Bank is the lender in the IGC High Efficiency Gas Equipment Finance Program. This program provides current and prospective customers an equipment-financing avenue that includes competitive rates and an expedited approval process. In related co-op advertising, Intermountain encourages participating HVAC dealers to promote high-efficiency furnaces and other equipment.

IGC is an active participant in the Rebuild Idaho energy efficiency campaign targeted toward our state, municipal and county entities, our school districts, and our institutions of higher education. IGC is an active voice in Idaho's legislative process as the lawmakers consider new, higher-efficiency building and energy codes.

IGC customer communications, mass-media advertising, website and marketing information all encourage gas users to consider using high-efficiency equipment when making their equipment purchase or upgrade decisions. Customer contact and marketing personnel are equipped and trained to assist current and potential customers with evaluating the advantages of installing high-efficiency gas equipment where possible.

The Gas Technology Institute (GTI) formerly known and the Gas Research Institute (GRI) continues to perform important ongoing research and development work in the gas equipment arena, from residential to large industrial. GTI is not just developing new uses for natural gas, but also improving the efficiency and cleanliness of existing applications. IGC participates in GTI's important research and development work through the pipeline funding mechanism established by FERC.

Natural gas equipment efficiency makes economic sense in today's new energy era, and IGC will continue to encourage new residential and commercial technologies, as they become available.

INDUSTRIAL EFFICIENCY

Intermountain is considering ways to enhance the efficient use of natural gas by the industrial endusers. The industrial customer's processes can be energy intensive and these customers already analyze and review their specific processes with competitiveness and energy efficiency in mind. Intermountain is reviewing the potential to offer assistance to these customers by providing real-time natural gas consumption information.

Because these relatively few customers account for approximately one-half of Intermountain's throughput, Intermountain consistently monitors and analyzes these loads through the use of its Supervisory Control and Data Acquisition ("SCADA) system. Intermountain is currently investigating technology enhancements that would allow the industrial customers to gain access to "real-time" natural gas usage data of their plants in a secure manner via the internet. When the industrial customer has the ability to see how specific processes or changes in procedures affect their natural gas usage, these customers may be encouraged to find new methods or technologies leading to a more efficient use of natural gas and a more competitive product.

ENERGY EFFICIENCY THROUGH THE DIRECT USE OF NATURAL GAS

Another, bigger-picture aspect of efficient natural gas usage is the concept of direct use, whenever possible. "Direct use" refers to employing natural gas at the user point for space heat, water heating, and other applications, as opposed to using natural gas to generate electricity to be transmitted to the user point and then employed for space or water heating.

As hydroelectric generating capacity becomes more constrained in the Pacific Northwest, additional generating capacity, either under construction or planned, tends to be natural gas fired. And while Intermountain favors the use of natural gas as a generating resource, direct use will mitigate the need for future natural gas fired generating capacity. If more homes and businesses use natural gas for heating and commercial applications, then fewer new generating plants will be needed. And at times of excess capacity, water storage normally used for generating power, can be released for additional irrigating, fish migration, and navigation uses.

Natural gas fired combustion turbines are generally 50 – 55% efficient at best. Further- more transmission and distribution losses can total another 5 – 10%. Effectively, half of the energy originally contained in the natural gas has been lost before arriving at the point of use.

High-efficiency natural gas furnaces are rated at 96% efficiency. So from a resource and environmental basis, direct use makes the most sense. Overall cost is lower as more energy is available for the customer who is also using less natural gas. Additionally, lower CO^2 emissions are spread out over a far wider airshed. Reduced natural gas usage will serve to help keep natural gas prices, and therefore, electricity prices, lower in the future.

NATURAL GAS AND AVOIDED ELECTRICAL GENERATION AND TRANSMISSION

To illustrate the significant role that IGC plays in southern Idaho's total energy picture, IGC has over 203,000 residential customers. Let's say 200,000 for this illustration. The average annual therm usage of an IGC space heating only customer is 625 therms. That equates to a total residential therm usage of 125,000,000 therms in a year. If the total was used at the Federal efficiency minimum of 78%, then (125,000,000 X .78 = 97,500,000 therms X 100,000 BTUs/therm) or 9,750,000,000,000 BTUs were used. (A therm is 100,000 BTUs of heat.) There are 3,412 BTUs in a kilowatt-hour. At 100% resistance heat efficiency, this means that the IGC residential space-heat customers would use the equivalent of

(9,750,000,000,000 / 3,412) or 2,857,600,000 kilowatt-hours to heat their homes. This is the same as 2,857,600 megawatt hours of power saved, year in, year out. According to their website, Idaho Power's total annual megawatt hour sales for 2000 were 19,127,188. Idaho Power's total sendout would rise to 21,984,788 megawatt hours, a 15% increase.

In peak terms, if these 200,000 IGC customers had electric furnaces with 25kw capacity, and just 1/3 of them were operating simultaneously during a cold-weather winter peak, there would be an additional winter peak load of 1,667 megawatts. Again, according to their website, the Idaho Power Winter 2000 peak load was 2,091 megawatts. without the direct use of natural gas to heat these 200,000 homes, Idaho Power's winter peak load could reach 3,758 megawatts, an 80% increase. This additional 1,667 megawatt peak load would be equivalent of seven 250 megawatt natural gas-fired electric generating facilities all running at full throttle. This would also require a substantial increase in transmission facilities to handle this peak load, since it would be well above the Idaho Power Summer 2000 peak of 2,919 megawatts.

In terms of recently avoided electric load, just since 1991, IGC has converted over 20,000 residential electric heating customers to natural gas. Using the consumption rates shown above, these gas conversions save about 286,000 megawatt hours sendout per year. In winter peak terms, using the "1/3 operating simultaneously" example in the paragraph above, 167 megawatts of peak load is saved. This is "year in, year out" electrical conversion is realized at no cost to the electric customers in Southern Idaho.

IGC's television advertising and other efforts actively target the electric to gas conversion market.

If this residential conversion customer conservation was priced at the $.15/kWh Idaho Power paid in its irrigation buy-back program in 2001, the cost to electric ratepayers for the aforementioned 286,000 megawatt hours would have been almost $43,000,000. Residential net-metering would value this conversation between $17,000,000 and $24,000,000.

All of the sendout and peak savings illustrations above consider only residential space heating. If residential natural gas water heating were included, the annual sendout figures would rise by at least 25%.

CONCLUSION

Natural gas is far and away, the best, most-efficient, lowest-cost, environmentally friendly electrical conservation and energy management tool available to Southern Idaho. Ever-increasing and more pervasive energy standards and practices will continue to improve the energy efficiency of Intermountain Gas Company's customers. Intermountain will continue in its active role as an important, coordinated energy resource for southern Idaho. Intermountain Gas Company will continue to endorse and encourage the wise and efficient use of energy in general and, in particular, natural gas. Intermountain will continue to encourage high efficiency natural gas furnaces with our rebate program, while our marketing and customer service efforts will continue to promote high efficiency equipment and conservation. The wise, direct use of natural gas in the coming years will help keep overall energy costs down in southern Idaho.

RESOURCE OPTIMIZATION

Introduction

The IRP model is an optimization model that selects resources over a pre-determined planning horizon to meet forecasted loads by minimizing the present value of fixed and variable resource costs. The model evaluates and selects least cost supply and transportation resources utilizing a standard mathematical technique called linear programming.

This summary will first describe the model structure and its assumptions in general. Initial results will then be discussed.

Components of the Model

The IRP model has three basic components:

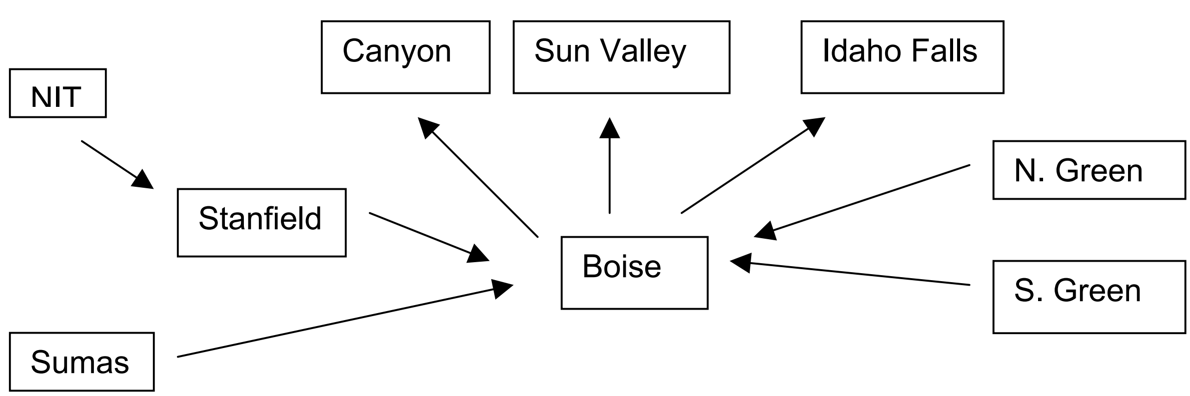
- demand forecast (See Exhibit 5, Appendix A)
- supply resources (See Exhibit 5, Appendix B)
- transportation resources (See Exhibit 5, Appendix C)

Underlying these three components is a structure of supply sources, transport capacity (arcs) and demand areas (nodes) which mirror how the IGC system contractually operates (see below). In any IRP model, there must be a balance between modeling in sufficient detail to capture all major economic impacts while at the same time, simplifying the system so that the model operates efficiently and the results are understandable. For an IRP model such as IGC's, where major supply and transport additions are being evaluated over a 5 year period, only major elements need to be recognized. This is in distinction to a dispatch model which needs to balance precisely requiring detail more fully representative of the system requirements. For this reason, a simplified structure is utilized in this IRP model.

Model Structure

The following table and graphic presents the demand and supply nodes and transport arcs of the IRP model.

Area #	1	2	3	4	5	6	7	8	9
Name	Sumas	Stanfield	Boise	Idaho Falls	N. Green	S. Green	NIT	Sun Valley	Canyon



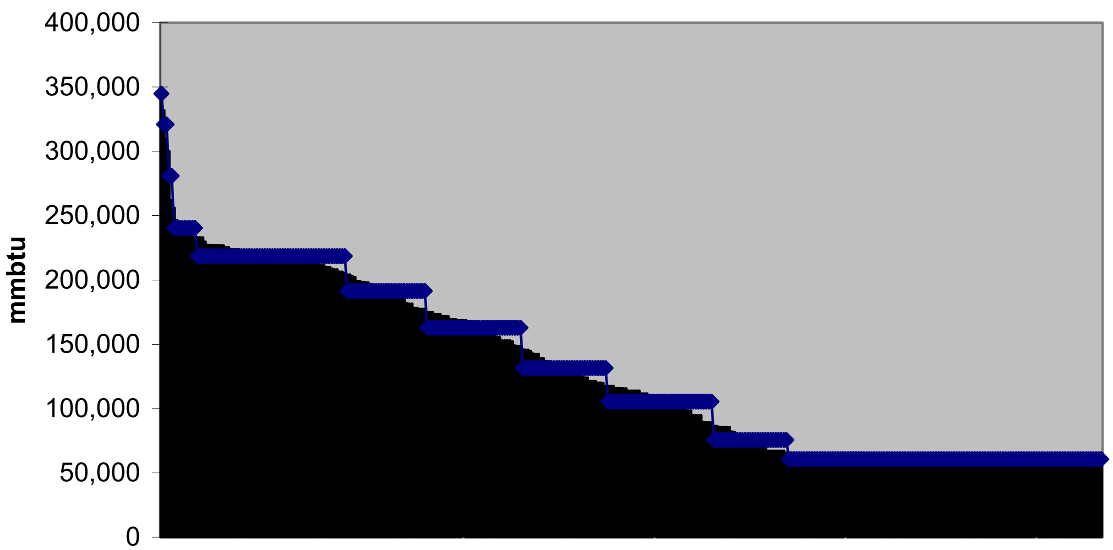
Demand Areas and Forecast

Four demand areas, or nodes, are designated: Boise, Canyon County, Sun Valley and Idaho Falls. Idaho Falls, Canyon County and Sun Valley reflect all loads served off the those specific “laterals” and are separated in order to facilitate the evaluation of distribution capacity enhancements for those laterals. Boise represents all loads outside of those demand nodes.

The model utilizes a peak-to-low load duration curve ("LDC") to represent the demand forecast. The graphic below depicts the LDC for the total system in FY03. This type of LDC summarizes load information from highest to lowest daily usage. The LDC approach is utilized for an IRP rather than a chronological approach to capture the general forecasting problem of planning for peak, shoulder and base demand in distinction to short term or daily dispatching. Design weather and projected customers are used to model forecast load requirements.

To simplify modeling, the LDC is aggregated into periods with similar load characteristics, to represent load changes over the entire year with a minimum of data points. (see Exhibit No. 1, Appendix A) The bold horizontal lines in the figure below provide an example of the aggregation periods utilized in the model. The model actually utilizes four separate LDCs so as to separately represent the Boise, Sun Valley, Canyon County, and Idaho Falls demand characteristics. The model assumes that IGC must provide gas supply, interstate and distribution transportation for core customers and only transportation for T-1 and T-2 customers. The T-4 customer's usage is only included for the distribution system.

Load Duration Design Base FY03



Supply Resources

Resource options for the model are of two types: storage resources and supply contracts; all are utilized in a similar manner. All resources have beginning and ending years of availability and they also have an annual flow capability and a peak day capability. They can be assigned both variable and fixed costs. Additionally, information relating to storage resources include injection period, injection rate, fuel losses and other storage related parameters are included.

Each resource must be designated to a delivery area. One advantage of certain storage facilities is that no additional mainline transport is required since the resource is either sited within a demand area node or is bundled with its own redelivery transport capacity. Resources can be delivered into the IGC system from Alberta (Nova Inventory Transfer or "NIT"), Sumas, Stanfield, North of Green River, or South of Green River, utilizing the appropriate transport arcs. Additionally, IGC system storage can be directly applied to the LDC for any demand node.

Transport Resources

Transport resources can be contracts for capacity such as those with Northwest Pipeline (NWP) or Pacific Gas Transmission ("PGT"), or for distribution mainlines such as the Idaho Falls lateral. Transport resources are explicitly associated with arcs in the model, which are usually contracts between supply and demand areas. For example, supply resources to be delivered from Sumas to Idaho Falls, first must use the Sumas to Boise arc and then the Boise to Idaho Falls arc. The system representation generally recognizes NWP's postage stamp pricing and capacity release.

Transport resources have a peak day capability, which is assumed to be available year round, unless otherwise noted. Transport resources can have different cost and capabilities assigned them as well as different years of availability. For example, different looping options for the Idaho Falls lateral are available to the model at different periods to facilitate timing decisions.

Model Operation

The selection of a best cost mix of resources, or resource optimization, is based on the cost availability and capability of the available resources as compared to the projected loads. The model chooses the mix of resources which best meet the optimization goal of minimizing the present value cost of delivering gas supply to meet customer demand. Both the fixed and variable costs of transport, storage and supply are included. The model will exclude resources it deems too expensive.

The model can treat fixed costs as sunk costs for certain resources. If a fixed cost or annual cost is entered for a resource, the model will include that cost for the resource in the selection process that will influence its inclusion vis-à-vis other available resources. If certain resources are committed to and the associated fixed cost will be paid in any event, only the variable cost of that resource is considered during the selection process. However, any "new" resources, which would be additional to the resource mix, will be evaluated using both fixed and variable cost.

The model operates in a PC environment. Inputs and outputs are in a spreadsheet format. The optimization is preformed by PC linear programming software.

Once the model computes the best resource mix, it writes the results to spreadsheet files, which are then organized by a set of macros in a summary spreadsheet.

Special Constraints

As stated earlier, the model minimized cost while satisfying demand and operational constraints. Several constraints specific to IGC's system were modeled in the IRP model.

- LNG, SGS, and LS storage either does not require redelivery transport capacity or has its own transportation for withdrawal; transportation utilization of this capacity must match storage withdrawal from these facilities.

- The T-1 and T-2 customers' transportation requirements are met utilizing IGC transport capacity but no supply resources are provided.

- The T-4 customer transportation requirements utilize only Intermountain's distribution capacity.

- Resources to the lateral nodes (e.g. such as Idaho Falls) must be transported first to Boise, and then from Boise to the lateral.

Model Results

The IRP optimization model for the five-year study, FY03 through FY07, is presented and discussed below. The results of the model are summarized, by demand scenario, by four types of tables:

- Resource Utilization Table
- Transport Utilization Table
- Storage Injection Table
- Annual Cost Summary

To refer to these tables please see: Baseline: See Exhibit 5, Appendix D; High Growth: See Exhibit 5, Appendix E; Low Growth Scenario: See Exhibit 6, Appendix F:

Each of these tables will be discussed as well as the results for years 1 and 5. The changes in model results between year 1 and year 5 will be summarized. The results for years 2 through 4 are available for review as part of the applicable appendix, but these tables will not be discussed.

Resource Utilization - General

The Resource Utilization Table (See Exhibit No. 5, Appendix D) provides usage information on supply and resources available to IGC. Column 1 corresponds to the resource number. Column 2 corresponds to a resource acronym, which the model utilizes for printouts. The next column identifies the arc to which the resources are delivered to NWP (or upstream arc where applicable). For example, the Sum-A resource is delivered to NWP at Sumas.

The utilization rates are the most important data determined by the model. These rates specify the percent of capability that the model determines are optimal for resources in each period. Tthe utilization rate by period for a resource multiplied by the resources capability on an MMBTU per day basis adjusted for a loss factor results in the daily capacity of that resource that is utilized by period, columns 13 through 18. The total column represents the simple sum of the daily capacities utilized. Note that total gas flow utilized per period is the capacity utilized per day times the number of days in a period and is contained in other detail tables.

There are generally three types of supply resources; existing supply contracts, existing storage contracts and incremental/spot contracts. Transport resources include both NWP capacity and upstream PGT capacity (to bring Alberta supply to NWP at Stanfield) as well as the capacities for the three laterals on the Intermountain system. The following sections will summarize the utilization of each type of supply and transport resource for the model years 1 and 5..

The model selects the best cost portfolio based on relative variable cost pricing. However, it also has been designed to comply with operational and contractual constraints that exist in the real world (i.e. if the most inexpensive supply is located as Sumas, the model can only take as much as can be transported from that point). It should also be noted here that in order for the results to provide a reasonable representation of actual operations, all existing resources that have committed cost contracts are assigned as must run resources. Other resources are evaluated by variable cost.

Another important assumption regarding "Fill" supply is that it is treated as an economic commodity meaning that its availability is dynamic. The model can select available Fill supply at any node, for any period and in any volume that it needs up to capacity constraints. To ensure that the model provides results that mirror reality, these supplies have been aggregated into Peak, Winter and summer price periods. Each aggregated group has a different relative price with the Peak price the highest and the Summer the lowest. Additionally, since term pricing is now normally based on the monthly spot index price through the utilization of futures, price swaps or other derivative products, no attempt has been made to develop fixed pricing for incremental term contracts.

The transportation utilization table provides the same type of information for transportation resources and is shown in a similar format as the resource utilization table. Each transportation resource has a resource number and acronym. In addition, the receipt ("from") and delivery ("to") points associated with each transport arc are listed in columns 3 and 4. Columns 5-10 show the transportation utilization rate output from the model and represent the percent of total resource available that the model utilizes by period. These utilization rates multiplied by the transport capability determine the daily transport capacity utilized by period as shown in columns 13-18.

Again, the incremental transportation "Fill" contracts are being treated as "commodity" resources in that the model can utilize this capacity in the period it needs it, but in somewhat limited volumes. The current assumption of on-demand incremental transport is likely not "real-world" since it would generally only be readily available on demand in the Summer. But, selection of this type of resource in a peak or winter period would generally indicate the need for a term contract of some nature.

Transportation resources fall into four categories: existing, Lateral capacity, storage, and incremental resources. The existing resources are labeled ES (NWP) or PGT. Lateral expansions demonstrate the need for their implementation by the change in utilization rates over time.

The storage injection table provides the amount of resources injected into the various storage facilities. Just as storage may only be withdrawn in the peak and winter periods, injections may only occur in winter, reflecting the actual withdrawal cycle in the winter and the injection cycle in the summer. The injection rate multiplied by the injection MMBTU and the loss factor results in the net MMBTU injected by period.

Summary Results – Baseline – Year 1

Supply.

The existing supply resources contracts 1 - 4, respectively, have utilization rates of 1.0 (or 100%) for all periods meaning that these resources are utilized at maximum capacity in all demand periods. This is due to contractual take obligations.

Storage facilities are fully withdrawn over Peak periods. In some instances, annual usage is less than full annual capability, but annual minimum withdrawals are achieved. There are a number of factors affecting shoulder usage such as cost, withdrawal capability, and transportation capacity. As loads continue to grow, further utilization of these facilities can be expected.

Resources labeled as NC-"xx" represent the non-core customer load resources. These resources are included to ensure that interstate transportation capacity is available for the non-core, firm transportation customers. The resource labeled as T-4 Boi represents the total system T-4 CD in order to ensure that distribution capacity is available for this transport load.

The remaining resources are general supply resources that are tied to Nemex Futures hub spot prices, which are used to fill in relative needs in various periods These resources are selected by the model only after existing contract supplies are utilized, due to pricing or contractual constraints.

Storage Injections. As described above, injections may only occur in the Summer period and after factoring in fuel losses, total injections match the withdrawals in the other periods for each facility. Although the storage cycle can overlap years (e.g. injections could actually occur in a subsequent year) in the real world, the nature of this model has resulted in a closed system: net injections must equal net withdrawals.

Transportation. All existing NWP capacity is fully utilized for Peak periods, which implies that absent any additional storage withdrawal capacity, Intermountain would require incremental fill capacity immediately. Approximately 25,600 MMBTU of incremental NWP fill capacity is selected. Lateral capacity expansion is required for the Sun Valley lateral.

Annual Cost Summary. Exhibit 5, Appendix D summarizes the dollar cost of the resources selected by the model, show the cost of supply resources utilized, reflects the transportation costs as determined by the model, and lists a grand total of all resource costs and calculates a net present value cost for comparative purposes.

Summary Results - Year 5

Supply. By the fifth year, the utilization of supply resources has changed somewhat to respond to load growth. Supply resources 1 through 4, are still utilized at full capacity. The load requirement that is met by firm "Fill" supply has increased from 9,000,000 therms to 36,900,000 therms.

Storage Injections. Storage is fully utilized, both on an annual and peak day basis. Injections in year 5 are higher than in year 1 due to the increase change in storage withdrawals and still occur in period 6 for all 5 storage facilities.

Transportation. As before, all existing NWP are fully utilized in peak periods and most of the PGT capacity is utilized year around. New transportation capacity totaling approximately 70,500 MMBTU has been selected for the peak day on NWP at Sumas, Stanfield and N. Green River. Two a lateral expansions have been selected on the Idaho Falls lateral, while both Sun Valley and Canyon County have utilized lateral expansions as well.